Kentucky Power Company

2008 Second Quarter Report

Financial Statements

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GLOSSARY OF TERMS

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

Term	Meaning
AEP or Parent	American Electric Power Company, Inc.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
ALJ	Administrative Law Judge.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
CAA	Clean Air Act.
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.).
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
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."
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN	FASB Interpretation No.
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.
FTR	Financial Transmission Right.
GAAP	Accounting Principles Generally Accepted in the United States of America.
IRS	Internal Revenue Service.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MTM	Mark-to-Market.
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.
OTC	Over-the-counter.
PUCT	Public Utility Commission of Texas.
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.
RTO	Regional Transmission Organization.
SECA	Seams Elimination Cost Allocation.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
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."

Term	Meaning
SFAS 159	Statement of Financial Accounting Standards No. 159, “The Fair Value Option for Financial Assets and Financial Liabilities.”
SIA	System Integration Agreement.
SO_2	Sulfur Dioxide.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Utility Money Pool	AEP System’s Utility Money Pool.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2008 and 2007
(in thousands)
(Unaudited)

	Three Months Ended		Six Months Ended	
	2008	**2007**	**2008**	**2007**
REVENUES				
Electric Generation, Transmission and Distribution	$ 128,152	$ 123,280	$ 275,211	$ 263,766
Sales to AEP Affiliates	18,729	11,162	38,782	24,623
Other	170	88	348	237
TOTAL	147,051	134,530	314,341	288,626
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	14,262	40,121	63,473	78,425
Purchased Electricity for Resale	5,706	3,457	9,472	6,762
Purchased Electricity from AEP Affiliates	60,262	43,578	114,452	86,835
Other Operation	13,877	14,632	29,385	30,518
Maintenance	16,603	10,337	26,523	18,547
Depreciation and Amortization	11,941	11,730	23,899	23,526
Taxes Other Than Income Taxes	2,872	2,973	4,052	5,776
TOTAL	125,523	126,828	271,256	250,389
OPERATING INCOME	21,528	7,702	43,085	38,237
Other Income (Expense):				
Interest Income	553	72	1,841	184
Allowance for Equity Funds Used During Construction	333	24	677	38
Interest Expense	(7,496)	(7,201)	(14,351)	(14,212)
INCOME BEFORE INCOME TAX EXPENSE (CREDIT)	14,918	597	31,252	24,247
Income Tax Expense (Credit)	3,988	(633)	9,178	7,806
NET INCOME	$ 10,930	$ 1,230	$ 22,074	$ 16,441

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

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2008 and 2007
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2006	$ 50,450	$ 208,750	$ 108,899	$ 1,552	$ 369,651
FIN 48 Adoption, Net of Tax			(786)		(786)
Common Stock Dividends			(8,999)		(8,999)
TOTAL					359,866
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,758				3,265	3,265
NET INCOME			16,441		16,441
TOTAL COMPREHENSIVE INCOME					19,706
JUNE 30, 2007	$ 50,450	$ 208,750	$ 115,555	$ 4,817	$ 379,572
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			(5,000)		(5,000)
TOTAL					381,604
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,796				(3,336)	(3,336)
NET INCOME			22,074		22,074
TOTAL COMPREHENSIVE INCOME					18,738
JUNE 30, 2008	$ 50,450	$ 208,750	$ 145,292	$ (4,150)	$ 400,342

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
June 30, 2008 and December 31, 2007
(in thousands)
(Unaudited)

	2008	2007
CURRENT ASSETS		
Cash and Cash Equivalents	$ 600	$ 727
Accounts Receivable:		
Customers	25,089	20,196
Affiliated Companies	5,794	15,984
Accrued Unbilled Revenues	2,267	2,904
Miscellaneous	108	178
Allowance for Uncollectible Accounts	(1,108)	(1,071)
Total Accounts Receivable	32,150	38,191
Fuel	11,119	8,338
Materials and Supplies	11,939	11,758
Risk Management Assets	41,852	12,121
Regulatory Asset for Under-Recovered Fuel Costs	12,613	4,426
Prepayments and Other	6,361	4,024
TOTAL	116,634	79,585
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	483,686	482,653
Transmission	404,962	402,259
Distribution	513,872	502,486
Other	63,145	61,665
Construction Work in Progress	78,064	46,439
Total	1,543,729	1,495,502
Accumulated Depreciation and Amortization	471,008	457,028
TOTAL - NET	1,072,721	1,038,474
OTHER NONCURRENT ASSETS		
Regulatory Assets	129,180	124,828
Long-term Risk Management Assets	22,738	14,826
Deferred Charges and Other	51,203	53,708
TOTAL	203,121	193,362
TOTAL ASSETS	$ 1,392,476	$ 1,311,421

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
June 30, 2008 and December 31, 2007
(Unaudited)

	2008	2007
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 48,435	$ 19,153
Accounts Payable:		
General	33,119	32,603
Affiliated Companies	24,870	29,437
Long-term Debt Due Within One Year – Nonaffiliated	30,000	30,000
Risk Management Liabilities	48,746	10,310
Customer Deposits	15,686	14,422
Accrued Taxes	10,692	16,875
Other	27,677	31,909
TOTAL	239,225	184,709
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	398,465	398,373
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	17,880	9,699
Deferred Income Taxes	250,750	240,858
Regulatory Liabilities and Deferred Investment Tax Credits	41,009	46,434
Deferred Credits and Other	24,805	24,379
TOTAL	752,909	739,743
TOTAL LIABILITIES	992,134	924,452
Commitments and Contingencies (Note 4)		
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	145,292	128,583
Accumulated Other Comprehensive Income (Loss)	(4,150)	(814)
TOTAL	400,342	386,969
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 1,392,476	$ 1,311,421

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2008 and 2007
(in thousands)
(Unaudited)

	2008	2007
OPERATING ACTIVITIES		
Net Income	$ 22,074	$ 16,441
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	23,899	23,526
Deferred Income Taxes	7,866	(1,042)
Allowance for Equity Funds Used During Construction	(677)	(38)
Mark-to-Market of Risk Management Contracts	3,309	2,406
Change in Other Noncurrent Assets	(2,106)	(789)
Change in Other Noncurrent Liabilities	(1,599)	(202)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	6,041	4,650
Fuel, Materials and Supplies	(2,962)	(3,346)
Accounts Payable	1,462	(11,273)
Accrued Taxes, Net	(5,369)	1,673
Fuel Over/Under-Recovery, Net	(8,187)	7,642
Other Current Assets	(3,150)	283
Other Current Liabilities	(3,373)	(2,398)
Net Cash Flows from Operating Activities	37,228	37,533
INVESTING ACTIVITIES		
Construction Expenditures	(61,434)	(27,771)
Proceeds from Sales of Assets	202	361
Net Cash Flows Used for Investing Activities	(61,232)	(27,410)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	29,282	(917)
Principal Payments for Capital Lease Obligations	(405)	(443)
Dividends Paid on Common Stock	(5,000)	(8,999)
Net Cash Flows from (Used for) Financing Activities	23,877	(10,359)
Net Decrease in Cash and Cash Equivalents	(127)	(236)
Cash and Cash Equivalents at Beginning of Period	727	702
Cash and Cash Equivalents at End of Period	$ 600	$ 466
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 14,536	$ 14,388
Net Cash Paid for Income Taxes	603	821
Noncash Acquisitions Under Capital Leases	126	394
Construction Expenditures Included in Accounts Payable at June 30,	6,648	3,419

See Condensed Notes to Condensed Financial Statements.

CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. Significant Accounting Matters
2. New Accounting Pronouncements
3. Rate Matters
4. Commitments, Guarantees and Contingencies
5. Benefit Plans
6. Business Segments
7. Income Taxes
8. Financing Activities

1. <u>SIGNIFICANT ACCOUNTING MATTERS</u>

General

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

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the results of operations, financial position and cash flows for the interim periods. The results of operations for the three and six months ended June 30, 2008 are not necessarily indicative of results that may be expected for the year ending December 31, 2008. The accompanying condensed financial statements are unaudited and should be read in conjunction with the audited 2007 financial statements and notes thereto, which are included in KPCo's 2007 Annual Report.

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 revisions had no impact on KPCo's previously reported results of operations or changes in shareholder's equity.

2. <u>NEW ACCOUNTING PRONOUNCEMENTS</u>

Upon issuance of final pronouncements, management thoroughly reviews the new accounting literature to determine the relevance, if any, to KPCo's business. The following represents a summary of new pronouncements issued or implemented in 2008 and standards issued but not implemented that management has determined relate to KPCo's operations.

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

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

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

SFAS 157 "Fair Value Measurements" (SFAS 157)

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

In February 2008, the FASB issued 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" (SFAS 13) and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement under SFAS 13.

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

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 derivatives are valued using broker or dealer quotations, similar observable market transactions in either the listed or OTC markets, or through 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. Generally, 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 that use internally developed model inputs, classified as level 3 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 June 30, 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 June 30, 2008

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets:					
Risk Management Contracts (a)	$ 7,613	$ 268,060	$ 2,300	$ (217,114)	$ 60,859
Cash Flow and Fair Value Hedges (a)	-	1,603	-	(1,061)	542
Dedesignated Risk Management Contracts (b)	-	-	-	3,189	3,189
Total Risk Management Assets	$ 7,613	$ 269,663	$ 2,300	$ (214,986)	$ 64,590
Liabilities:					
Risk Management Liabilities:					
Risk Management Contracts (a)	$ 8,109	$ 260,610	$ 6,270	$ (216,302)	$ 58,687
Cash Flow and Fair Value Hedges (a)	-	7,479	-	(1,061)	6,418
DETM Assignment (c)	-	-	-	1,521	1,521
Total Risk Management Liabilities	$ 8,109	$ 268,089	$ 6,270	$ (215,842)	$ 66,626

(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 13 in the 2007 Annual Report.

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

		Net Risk Management Assets (Liabilities) (in thousands)
Balance as of April 1, 2008	$	(205)
Realized (Gain) Loss Included in Earnings (or Changes in Net Assets) (a)		(112)
Unrealized Gain (Loss) Included in Earnings (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)		(467)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)		(3,186)
Balance as of June 30, 2008	$	(3,970)

		Net Risk Management Assets (Liabilities) (in thousands)
Balance as of January 1, 2008	$	(157)
Realized (Gain) Loss Included in Earnings (or Changes in Net Assets) (a)		(89)
Unrealized Gain (Loss) Included in Earnings (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)		(13)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)		(3,711)
Balance as of June 30, 2008	$	(3,970)

(a) Included in revenues on KPCo's Condensed Statement 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 Condensed Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities.

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

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

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

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

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

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

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 derivative instruments and related hedged items are accounted for under SFAS 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. SFAS 161 requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. This standard is intended to improve upon the existing disclosure framework in SFAS 133.

SFAS 161 is effective for fiscal years and interim periods beginning after November 15, 2008. Management expects this standard to increase the disclosure requirements related to derivative instruments and hedging activities. It encourages retrospective application to comparative disclosure for earlier periods presented. KPCo will adopt SFAS 161 effective January 1, 2009.

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.

SFAS 162 is effective 60 days after the SEC approves the Public Company Accounting Oversight Board's amendments to AU Section 411, "The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles." Management expects the adoption of this standard will have no impact on the financial statements. KPCo will adopt SFAS 162 when it becomes effective.

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

In March 2007, the FASB ratified EITF 06-10, a consensus on collateral assignment split-dollar life insurance arrangements in which an employee owns and controls the insurance policy. Under EITF 06-10, an employer should recognize a liability for the postretirement benefit related to a collateral assignment split-dollar life insurance arrangement in accordance with SFAS 106 "Employers' Accounting for Postretirement Benefits Other Than Pension" or Accounting Principles Board Opinion No. 12 "Omnibus Opinion – 1967" if the employer has agreed to maintain a life insurance policy during the employee's retirement or to provide the employee with a death benefit based on a substantive arrangement with the employee. In addition, an employer should recognize and measure an asset based on the nature and substance of the collateral assignment split-dollar life insurance arrangement. EITF 06-10 requires recognition of the effects of its application as either (a) a change in accounting principle through a cumulative effect adjustment to retained earnings or other components of equity or net assets in the statement of financial position at the beginning of the year of adoption or (b) a change in accounting principle through retrospective application to all prior periods. KPCo adopted EITF 06-10 effective January 1, 2008 with a cumulative effect reduction of $562 thousand ($365 thousand, net of tax) to beginning 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 ratified the EITF consensus on the treatment of income tax benefits of dividends on employee share-based compensation. The issue is how a company should recognize the income tax benefit received on dividends that are paid to employees holding equity-classified nonvested shares, equity-classified nonvested share units or equity-classified outstanding share options and charged to retained earnings under SFAS 123R, "Share-Based Payments." Under EITF 06-11, a realized income tax benefit from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for equity-classified nonvested equity shares, nonvested equity share units and outstanding equity share options should be recognized as an increase to additional paid-in capital. EITF 06-11 is applied prospectively to the income tax benefits of dividends on equity-classified employee share-based payment awards that are declared in fiscal years after December 15, 2007.

KPCo adopted EITF 06-11 effective January 1, 2008. The adoption of this standard had an immaterial impact on the financial statements.

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 under SFAS 142, "Goodwill and Other Intangible Assets." 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.

SFAS 142-3 is effective for interim and annual periods in fiscal years beginning after December 15, 2008. Early adoption is prohibited. Upon adoption, the guidance within SFAS 142-3 will be prospectively applied to intangible assets acquired after the effective date. Management expects that the adoption of this standard will have an immaterial impact on the financial statements. KPCo will adopt SFAS 142-3 effective January 1, 2009.

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

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

KPCo adopted FIN 39-1 effective January 1, 2008. This standard changed the method of netting certain balance sheet amounts and reduced assets and liabilities. 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:

Balance Sheet Line Description	As Reported for the December 2007 10-K	FIN 39-1 Reclassification	As Reported for the June 2008 10-Q
Current Assets:		(in thousands)	
Risk Management Assets	$ 12,480	$ (359)	$ 12,121
Prepayments and Other	4,701	(677)	4,024
Long-term Risk Management Assets	15,356	(530)	14,826
Current Liabilities:			
Risk Management Liabilities	10,974	(664)	10,310
Customer Deposits	15,312	(890)	14,422
Long-term Risk Management Liabilities	9,711	(12)	9,699

For certain risk management contracts, KPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the June 30, 2008 balance sheet, KPCo netted $5.1 million of cash collateral received from third parties against short-term and long-term risk management assets and $4.3 million of cash collateral paid to third parties against short-term and long-term risk management liabilities.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by the FASB, management cannot determine the impact on the reporting of operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, contingencies, liabilities and equity, emission allowances, leases, 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 results of operations and financial position.

3. RATE MATTERS

As discussed in KPCo's 2007 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within the 2007 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact results of operations, cash flows and possibly financial condition. The following discusses ratemaking developments in 2008 and updates the 2007 Annual Report.

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. 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, 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. The appeals process could take up to two years to complete. The AG agreed to stay its challenge during that time. KPCo's exposure is indeterminable at this time since it is not known whether a final adverse appeal could result in a refund of prior amounts collected, which would have an adverse effect on future results of operations and cash flows.

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 marginal 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 beginning May 2008. Therefore, in the second quarter of 2008, KPCo recorded $13 million of income and the related Regulatory Asset for Under-Recovered Fuel Costs for transmission line losses incurred from June 2007 through June 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 customers to make up the short fall in revenues.

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 that the FERC should reject the ALJ's initial decision because it contradicts prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ's findings on key issues are largely without merit. As a result, SECA ratepayers have been willing to engage with AEP in settlement discussions. AEP has been 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.

During 2006, the AEP East companies provided reserves of $37 million for net refunds for current and future SECA settlements. After reviewing existing settlements, the AEP East companies increased their reserves by an additional $5 million in December 2007. KPCo provided reserves of $3 million and $400 thousand in 2006 and 2007, respectively.

Completed and in-process settlements cover $107 million of the $220 million of SECA revenues and will consume about $7 million of the reserve for refund, leaving approximately $113 million of contested SECA revenues and $35 million of refund reserves.

If the FERC adopts the ALJ's decision and/or AEP cannot settle the remaining unsettled claims within the amount reserved for refunds, it will have an adverse effect on future results of operations 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 remaining reserve of $35 million is adequate to cover all remaining settlements. KPCo's portion of the reserve is $3 million. However, management cannot predict the ultimate outcome of ongoing settlement discussions or future FERC proceedings or court appeals, if such are necessary.

The FERC PJM Regional Transmission Rate Proceeding

With the elimination of T&O rates and the expiration of SECA rates and after considerable administrative litigation at the FERC in which AEP sought to mitigate the effect of T&O rate elimination, the FERC failed to implement a regional rate in PJM. As a result, the AEP East companies' retail customers incur the bulk of the cost of the existing AEP east transmission zone facilities. However, the FERC ruled that the cost of any new 500 kV and higher voltage transmission facilities built in PJM 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. AEP had requested rehearing of this order, which the FERC denied. 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, results of operations and cash flows.

The AEP East companies filed for and in 2006 obtained increases in its 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 85% of the lost T&O transmission revenues. AEP received net SECA transmission revenues of $128 million in 2005. I&M requested recovery 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 results of operations and cash flows will continue to be adversely affected in Indiana and Michigan until the remaining 15% 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 argues the use of other PJM and MISO facilities by AEP is not as large as the use of AEP transmission by others in PJM and MISO. Therefore, a regional rate design change is required to recognize that the provision and use of transmission service in the Super Region is not sufficiently uniform between transmission owners and users to justify zonal rates. In January 2008, the FERC denied AEP's complaint. AEP filed a rehearing request with the FERC in March 2008. Should this effort be successful, earnings could benefit for a certain period due to regulatory lag; however, AEP East companies would 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. 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 additional annual revenues for AEP of approximately $9 million from nonaffiliated customers within PJM. AEP requested an effective date of October 1, 2008. Management is unable to predict the outcome of this filing.

Allocation of Off-system Sales Margins

In August 2007, the OCC issued an order adopting the ALJ's recommendation that the allocation of system sales/trading margins is a FERC jurisdictional issue. In October 2007, the OCC orally directed the OCC staff to explore filing a complaint at FERC alleging the allocation of off-system sales margins to PSO is improper. In June 2008, the ALJ issued a final recommendation and incorporated the prior finding that the OCC lacked authority to review AEP's application of a FERC-approved methodology. The OCC is scheduled to consider the final recommendation in August 2008.

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

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

FERC Market Power Mitigation

The FERC allows utilities to sell wholesale power at market-based rates if they can demonstrate that they lack market power in the markets in which they participate. Sellers with market rate authority must, at least every three years, update their studies demonstrating lack of market power. In December 2007, AEP filed its most recent triennial update. In March and May 2008, the PUCO filed comments suggesting that the FERC should further investigate whether AEP continues to pass the FERC's indicative screens for the lack of market power in PJM. Certain industrial retail customers also urged the FERC to further investigate this matter. AEP responded that its market power studies were performed in accordance with the FERC's guidelines, and continue to demonstrate lack of market power.

Management is unable to predict the outcome of this proceeding; however, if a further investigation by the FERC limited AEP's ability to sell power at market based rates in PJM, it would result in an adverse effect on future off-system sales margins, results of operations and cash flows.

4. COMMITMENTS, GUARANTEES AND CONTINGENCIES

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, 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. The Commitments, Guarantees and Contingencies note within the 2007 Annual Report should be read in conjunction with this report.

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

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. Prior to June 30, 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 power purchase and sale activity conducted pursuant to the SIA.

Master Operating Lease

KPCo leases certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, KPCo has committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. Historically, at the end of the lease term the fair market value has been in excess of the unamortized balance. Assuming the fair market value of the equipment is zero at the end of the lease term, the maximum potential loss for these lease agreements was approximately $2 million as of June 30, 2008.

CONTINGENCIES

Carbon Dioxide (CO_2) Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The dismissal of this lawsuit was appealed to the Second Circuit Court of Appeals. Briefing and oral argument have concluded. 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. 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. Management believes the action is without merit and intends to defend against the claims.

Clean Air Act Interstate Rule

In 2005, the Federal EPA issued a final rule, the Clean Air Interstate Rule (CAIR), that required further reductions in SO_2 and NO_x emissions and assists states developing new state implementation plans to meet 1997 national ambient air quality standards (NAAQS). CAIR reduces regional emissions of SO_2 and NO_x (which can be transformed into PM and ozone) from power plants in the Eastern U.S. (29 states and the District of Columbia). Reduction of both SO_2 and NO_x would be achieved through a cap-and-trade program. In July 2008, the D.C. Circuit Court of Appeals vacated the CAIR and remanded the rule to the Federal EPA. We are unable to predict how the Federal EPA will respond to the remand which could be stayed or appealed to the U.S. Supreme Court.

KPCo did not purchase any significant number of CAIR allowances. SO_2 and seasonal NO_x allowances allocated to the AEP System's facilities under the Acid Rain Program and the NO_x SIP Call will still be required to comply with existing CAA programs that were not affected by the court's decision.

It is too early to determine the full implication of these decisions on environmental compliance strategy. However, independent obligations under the CAA, including obligations under future state implementation plan submittals, and actions taken pursuant to the recent settlement of the NSR enforcement action, are consistent with the actions included in a least-cost CAIR compliance plan. Consequently, management does not anticipate making any immediate changes in near-term compliance plans as a result of these court decisions.

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 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. Management is unable to predict the outcome of these proceedings or their impact on future results of operations and cash flows. Management asserted claims against certain companies that sold power to KPCo and 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.

5. BENEFIT PLANS

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

Components of Net Periodic Benefit Cost

The following tables provide the components of AEP's net periodic benefit cost for the plans for the three and six months ended June 30, 2008 and 2007:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2008	2007	2008	2007
	(in millions)			
Service Cost	$ 25	$ 23	$ 11	$ 11
Interest Cost	62	57	28	26
Expected Return on Plan Assets	(84)	(82)	(28)	(26)
Amortization of Transition Obligation	-	-	7	7
Amortization of Net Actuarial Loss	10	14	2	3
Net Periodic Benefit Cost	$ 13	$ 12	$ 20	$ 21

	Pension Plans		Other Postretirement Benefit Plans	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(in millions)			
Service Cost	$ 50	$ 47	$ 21	$ 21
Interest Cost	125	116	56	52
Expected Return on Plan Assets	(168)	(167)	(56)	(52)
Amortization of Transition Obligation	-	-	14	14
Amortization of Net Actuarial Loss	19	29	5	6
Net Periodic Benefit Cost	$ 26	$ 25	$ 40	$ 41

The following table provides KPCo's net periodic benefit cost for the plans for the three and six months ended June 30, 2008 and 2007:

	Pension Plans		Other Postretirement Benefit Plans	
	2008	2007	2008	2007
	(in thousands)			
Three Months Ended June 30,	$ 249	$ 254	$ 400	$ 427
Six Months Ended June 30,	498	509	801	853

6. BUSINESS SEGMENTS

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

7. INCOME TAXES

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

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

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

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

State Tax Legislation

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 results of operations, cash flows or financial condition.

8. FINANCING ACTIVITIES

Lines of Credit

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 June 30, 2008 and December 31, 2007 are included in Advances from Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limit for the six months ended June 30, 2008 are described in the following table:

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 June 30, 2008	Authorized Short-Term Borrowing Limit
(in thousands)					
$ 51,504	$ -	$ 31,644	$ -	$ 48,435	$ 250,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool for the six months ended June 30, 2008 and 2007 are summarized in the following table:

	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 Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2008	5.37%	2.91%	-%	-%	3.39%	-%
2007	5.46%	5.30%	-%	-%	5.36%	-%

Credit Facilities

In April 2008, the Parent, the AEP East companies and the AEP West companies entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement. Under the facilities, letters of credit may be issued. As of June 30, 2008, there were no outstanding amounts for KPCo under either facility.