KENTUCKY POWER COMPANY

KENTUCKY POWER COMPANY
SELECTED FINANCIAL DATA
(in thousands)

	2004	2003	2002	2001	2000
STATEMENTS OF INCOME DATA					
Operating Revenues	$ 450,613	$ 416,470	$ 378,683	$ 379,025	$ 389,875
Operating Income	55,321	64,744	42,197	47,678	49,738
Interest Charges	29,470	28,620	26,836	27,361	31,045
Income Before Cumulative Effect of Accounting Change	25,905	33,464	20,567	21,565	20,763
Cumulative Effect of Accounting Change, Net of Tax	-	(1,134)	-	-	-
Net Income	25,905	32,330	20,567	21,565	20,763
BALANCE SHEETS DATA					
Electric Utility Plant	$ 1,361,547	$ 1,349,746	$ 1,295,619	$ 1,128,415	$ 1,103,064
Accumulated Depreciation and Amortization	398,455	381,876	373,638	360,319	338,270
Net Electric Utility Plant	$ 963,092	$ 967,870	$ 921,981	$ 768,096	$ 764,794
Total Assets	$ 1,243,247	$ 1,221,634	$ 1,188,342	$ 1,022,833	$ 1,516,921
Common Shareholder's Equity	320,980	317,138	298,018	256,130	266,713
Long-term Debt (a)	508,310	487,602	466,632	346,093	330,880
Obligations Under Capital Leases (a)	4,363	5,292	7,248	9,583	14,184

(a) Including portion due within one year.

KENTUCKY POWER COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

KPCo is a public utility engaged in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 175,000 retail customers in our service territory in eastern Kentucky. As a member of the AEP Power Pool, we share the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers. We also sell power at wholesale to municipalities.

The cost of the AEP Power Pool's generating capacity is allocated among its members based on their relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity credits. 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.

Power and gas risk management activities are conducted on our behalf by AEPSC. We share in the revenues and expenses associated with these risk management activities with other Registrant Subsidiaries excluding AEGCo under existing power pool and system integration agreements. 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. The electricity and gas contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. The majority of the physical forward contracts are typically settled by entering into offsetting contracts.

Under our system integration agreement, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management entities are shared among AEP East and West companies. Sharing in a calendar year is based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East and West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East and West companies in the event the pre-merger activity level is exceeded. The capacity based allocation mechanism was triggered in July 2004 and June 2003, resulting in an allocation factor of approximately 70% and 30% for the AEP East and West companies, respectively, for the remainder of the respective year. In 2002, the capacity based allocation mechanism was not triggered.

On October 1, 2004, our transmission and generation operations, commercial processes and data systems were integrated into those of PJM. While we continue to own our transmission assets, use our low-cost generation plant to serve the needs of our native-load customers, and sell available generation to other parties, we are performing those functions through PJM via the AEP Power Pool, discussed above.

During the fourth quarter of 2004, our PJM-related operating results came in as expected, in spite of having to overcome the initial learning curve of operating in the new environment. We are confident in our ability to participate successfully in the PJM market.

To minimize the credit requirements and operating constraints when joining PJM, the AEP East Companies as well as Wheeling Power Company and Kingsport Power Company, have agreed to a netting of all payment obligations incurred by any of the AEP East companies against all balances due 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.

We are jointly and severally liable for activity conducted by AEPSC on the behalf of AEP East and West companies and activity conducted by any Registrant Subsidiary pursuant to the system integration agreement.

Results of Operations

Net Income for 2004 decreased $6 million over the prior year primarily due to increases in planned boiler overhaul outages and administrative and support expenses.

2004 Compared to 2003

Operating Income

Operating Income for 2004 decreased by $9 million from 2003 primarily due to:

- A $25 million increase in Fuel for Electric Generation expenses resulting from an increase in the cost of coal consumed and a 6% increase in electric generation.
- An $8 million increase in Purchased Energy for Resale expenses primarily related to coal trading purchases from procurement contracts.
- A $5 million increase in Maintenance expense caused by planned boiler overhaul outages in the first and second quarters of 2004 as well as a turbine repair outage in the fourth quarter of 2004.
- A $5 million increase in Depreciation and Amortization expense primarily related to the installation of emission control equipment at the Big Sandy plant in mid-2003.
- A $4 million increase in Other Operation expense resulting from increased administrative and support expenses in 2004.

The decrease in Operating Income for 2004 was partially offset by:

- A $32 million increase in Electric Generation, Transmission and Distribution revenues due primarily to an improvement in commercial and industrial sales, the rate increase in mid-2003 to recover the cost of emission control equipment, increased fuel recoveries related to increased fuel costs, and increased revenues related to coal trading sales.
- A $3 million decrease in Income Taxes. See Income Taxes section below for further discussion.
- A $2 million increase in Sales to AEP Affiliates reflecting recovery of increased generation expenses.

Other Impacts on Earnings

Nonoperating Income increased $5 million in 2004 compared to 2003 primarily due to favorable results from risk management activities.

Nonoperating Income Tax Credit decreased $2 million in 2004 compared to 2003. See Income Taxes section below for further discussion.

Income Taxes

The effective tax rates for 2004 and 2003 were 25.1% and 22.4%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to flow-through of book versus tax temporary differences, amortization of investment tax credits, state income taxes and federal income tax adjustments. The increase in the effective tax rate for the comparative period is primarily due to less favorable federal income tax adjustments.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings are as follows:

	Moody's	S&P	Fitch
Senior Unsecured Debt	Baa2	BBB	BBB

Summary Obligation Information

Our contractual obligations include amounts reported on the Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2004:

Payment Due by Period
(in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After	Total

				5 years	
Long-term Debt (a)	$ -	$ 383.0	$ 30.0	$ 95.0	$ 508.0
Capital Lease Obligations (b)	1.9	2.2	0.7	0.1	4.9
Noncancelable Operating Leases (b)	1.5	2.1	1.3	1.8	6.7
Fuel Purchase Contracts (c)	84.7	159.6	3.9	-	248.2
Energy and Capacity Purchase Contracts (d)	5.1	7.6	-	-	12.7
Total	$ 93.2	$ 554.5	$ 35.9	$ 96.9	$ 780.5

(a) See Schedule of Long-term Debt. Represents principal only excluding interest.
(b) See Note 15.
(c) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.
(d) Represents contractual cash flows of energy and capacity purchase contracts.

Significant Factors

See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section for additional discussion of factors relevant to us.

Critical Accounting Estimates

See "Critical Accounting Estimates" section in "Combined Management's Discussion and Analysis of Registrant Subsidiaries" for a discussion of the estimates and judgments required for revenue recognition, the valuation of long-lived assets, pension benefits, income taxes, and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our risk management policies and procedures are instituted and administered at the AEP Consolidated level. See complete discussion within AEP's "Quantitative and Qualitative Disclosures About Risk Management Activities" section. The following tables provide information about AEP's risk management activities' effect on us.

MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets
Year Ended December 31, 2004
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2003	$ 15,490
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(5,611)
Fair Value of New Contracts When Entered During the Period (b)	-
Net Option Premiums Paid/(Received) (c)	(106)
Change in Fair Value Due to Valuation Methodology Changes (d)	-
Changes in Fair Value of Risk Management Contracts (e)	496
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (f)	2,422
Total MTM Risk Management Contract Net Assets	12,691
Net Cash Flow and Fair Value Hedge Contracts (g)	1,102
DETM Assignment (h)	(5,570)
Total MTM Risk Management Contract Net Assets at December 31, 2004	$ 8,223

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2004 where we entered into the contract prior to 2004.
(b) "Fair Value of New Contracts When Entered During the Period" represents the fair value at inception of long-term contracts entered into with customers during 2004. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
(c) "Net Option Premiums Paid/(Received)" reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered in 2004.
(d) "Change in Fair Value Due to Valuation Methodology Changes" represents the impact of AEP changes in methodology in regards to credit reserves on forward contracts.
(e) "Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(f) "Change in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
(g) "Net Cash Flow and Fair Value Hedge Contracts" (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).
(h) See "AEP East Companies" in Note 17.

Reconciliation of MTM Risk Management Contracts to
Balance Sheets
As of December 31, 2004
(in thousands)

	MTM Risk Management Contracts (a)	Hedges	DETM Assignment (b)	Total (c)
Current Assets	$ 15,691	$ 4,154	$ -	$ 19,845
Noncurrent Assets	19,063	4	-	19,067
Total MTM Derivative Contract Assets	34,754	4,158	-	38,912
Current Liabilities	(11,784)	(2,697)	(2,724)	(17,205)
Noncurrent Liabilities	(10,279)	(359)	(2,846)	(13,484)
Total MTM Derivative Contract Liabilities	(22,063)	(3,056)	(5,570)	(30,689)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 12,691	$ 1,102	$ (5,570)	$ 8,223

(a) Does not include Cash Flow and Fair Value Hedges.
(b) See "AEP East Companies" in Note 17.
(c) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Balance Sheets.

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

- The source of fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities, giving an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets
Fair Value of Contracts as of December 31, 2004
(in thousands)

	2005	2006	2007	2008	2009	After 2009	Total (c)
Prices Actively Quoted - Exchange Traded Contracts	$ (1,107)	$ (40)	$ 557	$ -	$ -	$ -	$ (590)
Prices Provided by Other External Sources - OTC Broker Quotes (a)	5,236	2,133	1,882	676	-	-	9,927
Prices Based on Models and Other Valuation Methods (b)	(222)	(223)	(233)	1,027	1,464	1,541	3,354
Total	$ 3,907	$ 1,870	$ 2,206	$ 1,703	$ 1,464	$ 1,541	$ 12,691

(a) "Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.
(c) Amounts exclude Cash Flow and Fair Value Hedges.

Cash Flow Hedges Included in Accumulated Other Comprehensive Income (Loss) (AOCI) on the Balance Sheet

We are exposed to market fluctuations in energy commodity prices impacting our power operations. We monitor these risks on our future operations and may employ various commodity instruments to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

We employ cash flow hedges to mitigate changes in interest rates or fair values on short-term and long-term debt when management deems it necessary. We do not hedge all interest rate risk.

The table provides detail on effective cash flow hedges under SFAS 133 included in the Balance Sheets. The data in the table will indicate the magnitude of SFAS 133 hedges we have in place. Under SFAS 133, only contracts designated as cash flow hedges are recorded in AOCI; therefore, economic hedge contracts which are not designated as cash flow hedges are required to be marked-to-market and are included in the previous risk management tables. In accordance with GAAP, all amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2004
(in thousands)

	Power	Interest Rate	Total
Beginning Balance December 31, 2003	$ 82	$ 338	$ 420
Changes in Fair Value (a)	918	-	918
Reclassifications from AOCI to Net Income (b)	(431)	(94)	(525)
Ending Balance December 31, 2004	$ 569	$ 244	$ 813

(a) "Changes in Fair Value" shows changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at December 31, 2004. Amounts are reported net of related income taxes.
(b) "Reclassifications from AOCI to Net Income" represents gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into net income during the reporting period. Amounts are reported net of related income taxes.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is an $800 thousand gain.

Credit Risk

Our counterparty credit quality and exposure is generally consistent with that of AEP.

VaR Associated with Risk Management Contracts

The following table shows the end, high, average, and low market risk as measured by VaR for the years:

December 31, 2004 (in thousands)				December 31, 2003 (in thousands)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$135	$442	$191	$65	$136	$527	$220	$52

VaR Associated with Debt Outstanding

The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was $16 million and $29 million at December 31, 2004 and 2003, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or financial position.

KENTUCKY POWER COMPANY
STATEMENTS OF INCOME
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	2004	2003	2002
OPERATING REVENUES			
Electric Generation, Transmission and Distribution	$ 409,023	$ 376,662	$ 350,719
Sales to AEP Affiliates	41,590	39,808	27,964
TOTAL	450,613	416,470	378,683
OPERATING EXPENSES			
Fuel for Electric Generation	99,456	74,148	65,043
Purchased Energy for Resale	8,532	963	29
Purchased Electricity from AEP Affiliates	140,758	141,690	133,002
Other Operation	51,757	47,325	52,892
Maintenance	32,802	27,328	35,089
Depreciation and Amortization	43,847	39,309	33,233
Taxes Other Than Income Taxes	9,145	8,788	8,240
Income Taxes	8,995	12,175	8,958
TOTAL	395,292	351,726	336,486
OPERATING INCOME	55,321	64,744	42,197
Nonoperating Income (Loss)	1,298	(4,036)	7,950
Nonoperating Expenses	1,568	1,124	840
Nonoperating Income Tax Expense (Credit)	(324)	(2,500)	1,904
Interest Charges	29,470	28,620	26,836
Income Before Cumulative Effect of Accounting Change	25,905	33,464	20,567
Cumulative Effect of Accounting Change, Net of Tax	-	(1,134)	-
NET INCOME	$ 25,905	$ 32,330	$ 20,567

The common stock of KPCo is wholly-owned by AEP

See Notes to Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2001	$ 50,450	$ 158,750	$ 48,833	$ (1,903)	$256,130
Capital Contribution from Parent		50,000			50,000
Common Stock Dividends			(21,131)		(21,131)
TOTAL					284,999
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,198				2,225	2,225
Minimum Pension Liability, Net of Tax of $5,262				(9,773)	(9,773)
NET INCOME			20,567		20,567
TOTAL COMPREHENSIVE INCOME					13,019
DECEMBER 31, 2002	50,450	208,750	48,269	(9,451)	298,018
Common Stock Dividends			(16,448)		(16,448)
TOTAL					281,570
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $53				98	98
Minimum Pension Liability, Net of Tax of $1,691				3,140	3,140
NET INCOME			32,330		32,330
TOTAL COMPREHENSIVE INCOME					35,568
DECEMBER 31, 2003	50,450	208,750	64,151	(6,213)	317,138
Common Stock Dividends			(19,501)		(19,501)
TOTAL					297,637
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $212				393	393
Minimum Pension Liability, Net of Tax of $1,592				(2,955)	(2,955)
NET INCOME			25,905		25,905

TOTAL COMPREHENSIVE INCOME					23,343
DECEMBER 31, 2004	$ 50,450	$ 208,750	$ 70,555	$ (8,775)	$320,980

See Notes to Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY
BALANCE SHEETS
ASSETS
December 31, 2004 and 2003
(in thousands)

	2004	2003
ELECTRIC UTILITY PLANT		
Production	$ 462,641	$ 457,341
Transmission	385,667	381,354
Distribution	438,766	425,688
General	57,929	68,041
Construction Work in Progress	16,544	17,322
Total	1,361,547	1,349,746
Accumulated Depreciation and Amortization	398,455	381,876
TOTAL - NET	963,092	967,870
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	5,438	5,423
Other Investments	422	1,022
TOTAL	5,860	6,445
CURRENT ASSETS		
Cash and Cash Equivalents	127	863
Other Cash Deposits	5	23
Advances to Affiliates	16,127	-
Accounts Receivable:		
Customers	22,130	21,177
Affiliated Companies	23,046	25,327
Accrued Unbilled Revenues	7,340	5,534
Miscellaneous	94	97
Allowance for Uncollectible Accounts	(34)	(736)
Fuel	6,551	9,481
Materials and Supplies	9,385	8,831
Risk Management Assets	19,845	16,200
Margin Deposits	1,960	2,660
Prepayments and Other	1,782	1,696
TOTAL	108,358	91,153
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	103,849	99,828
Other	14,558	13,971
Long-term Risk Management Assets	19,067	16,134
Emission Allowances	9,666	7,754
Deferred Property Taxes	7,036	6,847
Deferred Charges and Other	11,761	11,632
TOTAL	165,937	156,166
TOTAL ASSETS	$ 1,243,247	$ 1,221,634

See Notes to Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY
BALANCE SHEETS
CAPITALIZATIONAND LIABILITIES
December 31, 2004 and 2003

	2004	2003
CAPITALIZATION	(in thousands)	
Common Shareholder's Equity:		
Common Stock - $50 Par Value Per Share:		
Authorized - 2,000,000 Shares		
Outstanding - 1,009,000 Shares	$ 50,450	$ 50,450
Paid-in Capital	208,750	208,750
Retained Earnings	70,555	64,151
Accumulated Other Comprehensive Income (Loss)	(8,775)	(6,213)
Total Common Shareholder's Equity	320,980	317,138
Long-term Debt:		
Nonaffiliated	428,310	427,602
Affiliated	80,000	60,000
Total Long-term Debt	508,310	487,602
TOTAL	829,290	804,740
CURRENT LIABILITIES		
Accounts Payable:		
General	20,080	22,802
Affiliated Companies	24,899	22,648
Advances from Affiliates	-	38,096
Risk Management Liabilities	17,205	11,704
Taxes Accrued	9,248	7,329
Interest Accrued	6,754	6,915
Customer Deposits	12,309	9,894
Obligations Under Capital Leases	1,561	1,743
Other	9,038	8,628
TOTAL	101,094	129,759
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	227,536	212,121
Regulatory Liabilities:		
Asset Removal Costs	28,232	26,140
Deferred Investment Tax Credits	6,722	7,955
Other Regulatory Liabilities	15,622	10,591
Employee Benefits and Pension Obligations	17,729	13,999
Long-term Risk Management Liabilities	13,484	12,363
Obligations Under Capital Leases	2,802	3,549
Deferred Credits	736	417
TOTAL	312,863	287,135
Commitments and Contingencies (Note 7)		
TOTAL CAPITALIZATIONAND LIABILITIES	$ 1,243,247	$ 1,221,634

See Notes to Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2004, 2003 and 2002
(in thousands)

	2004	2003	2002
OPERATING ACTIVITIES			
Net Income	$ 25,905	$ 32,330	$ 20,567
Adjustments to Reconcile Net Income to			
Net Cash Flows From Operating Activities:			
Cumulative Effect of Accounting Changes	-	1,134	-
Depreciation and Amortization	43,847	39,309	33,233
Deferred Income Taxes	12,774	20,107	9,839
Deferred Investment Tax Credits	(1,233)	(1,210)	(1,240)
Deferred Property Taxes	(189)	(547)	(338)
Deferred Fuel Costs, Net	1,164	233	2,998
Mark-to-Market of Risk Management Contracts	1,020	15,112	(12,267)
Change in Other Noncurrent Assets	(7,269)	(15,184)	(22,187)
Change in Other Noncurrent Liabilities	8,147	6,224	(5,898)
Changes in Components of Working Capital:			
Accounts Receivable, Net	(1,177)	2,445	(9,332)
Fuel, Materials and Supplies	2,376	2,250	3,170
Accounts Payable	(471)	(45,100)	44,529
Taxes Accrued	1,919	8,582	(11,558)
Customer Deposits	2,415	1,846	3,588
Interest Accrued	(161)	444	1,202
Other Current Assets	614	(2,229)	(812)
Other Current Liabilities	226	(3,949)	16,827
Net Cash Flows From Operating Activities	89,907	61,797	72,321
INVESTING ACTIVITIES			
Construction Expenditures	(38,475)	(81,707)	(178,700)
Change in Other Cash Deposits, Net	18	(4)	17
Proceeds from Sale of Assets	1,538	967	-
Other	-	-	217
Net Cash Flows Used For Investing Activities	(36,919)	(80,744)	(178,466)
FINANCING ACTIVITIES			
Capital Contributions from Parent	-	-	50,000
Issuance of Long-term Debt - Nonaffiliated	-	74,263	-
Issuance of Long-term Debt - Affiliated	20,000	-	274,964
Retirement of Long-term Debt - Nonaffiliated	-	(40,000)	(154,500)
Retirement of Long-term Debt - Affiliated	-	(15,000)	
Change in Advances to/from Affiliates, Net	(54,223)	14,710	(42,814)
Dividends Paid	(19,501)	(16,448)	(21,131)
Net Cash Flows From (Used For) Financing Activities	(53,724)	17,525	106,519
Net Increase (Decrease) in Cash and Cash Equivalents	(736)	(1,422)	374
Cash and Cash Equivalents at Beginning of Period	863	2,285	1,911
Cash and Cash Equivalents at End of Period	$ 127	$ 863	$ 2,285

SUPPLEMENTAL DISCLOSURE:

Cash paid for interest net of capitalized amounts was $28,367,000, $26,988,000 and $25,176,000 in 2004, 2003 and 2002, respectively. Cash paid (received) for income taxes was $(3,233,000), $(17,574,000) and $13,041,000 in 2004, 2003 and 2002, respectively. Noncash acquisitions under capital leases were $925,000, $0 and $22,000 in 2004, 2003 and 2002, respectively.

See Notes to Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY
SCHEDULE OF LONG-TERM DEBT
December 31, 2004 and 2003

	2004	2003
	(in thousands)	
LONG-TERM DEBT:		
Senior Unsecured Notes	$ 428,310	$ 427,602
Notes Payable - Affiliated	80,000	60,000
Long-term Debt Excluding Portion Due Within One Year	$ 508,310	$ 487,602

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

Senior Unsecured Notes outstanding were as follows:

% Rate	Due	2004	2003
		(in thousands)	
6.910	2007 - October 1	$ 48,000	$ 48,000
6.450	2008 - November 10	30,000	30,000
5.500	2007 - July 1	125,000	125,000
4.310	2007 - November 12	80,400	80,400
4.370	2007 - December 12	69,564	69,564
5.625	2032 - December 31	75,000	75,000
Unamortized Discount		(268)	(362)
Interest Rate Hedge		614	-
Total		$ 428,310	$ 427,602

Notes Payable to Parent were as follows:

% Rate	Due	2004	2003
		(in thousands)	
6.501	2006 - May 15	$ 60,000	$ 60,000
5.250	2015 - June 1	20,000	-
Total		$ 80,000	$ 60,000

At December 31, 2004, future annual long-term debt payments are as follows:

	Amount
	(in thousands)
2005	$ -
2006	60,000
2007	322,964
2008	30,000
2009	-
Later Years	95,000
Total Principal Amount	507,964
Unamortized Discount	(268)
Interest Rate Hedge	614
Total	$ 508,310

KENTUCKY POWER COMPANY
INDEX TO NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The notes to KPCo's financial statements are combined with the notes to financial statements for other registrant subsidiaries. Listed below are the notes that apply to KPCo.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying balance sheets of Kentucky Power Company as of December 31, 2004 and 2003, 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, 2004. 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 the 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. An audit includes 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, 2004 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the financial statements, the Company adopted EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," effective January 1, 2003 and FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003," effective April 1, 2004.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2005