KENTUCKY POWER COMPANY

KENTUCKY POWER COMPANY
SELECTED FINANCIAL DATA
(in thousands)

	2006	2005	2004	2003	2002
STATEMENTS OF INCOME DATA					
Total Revenues	$ 585,867	$ 531,343	$ 448,961	$ 412,667	$ 391,516
Operating Income	$ 81,625	$ 60,831	$ 63,339	$ 70,749	$ 57,579
Income Before Cumulative Effect of Accounting Change	$ 35,035	$ 20,809	$ 25,905	$ 33,464	$ 20,567
Cumulative Effect of Accounting Change, Net of Tax	-	-	-	(1,134)	-
Net Income	$ 35,035	$ 20,809	$ 25,905	$ 32,330	$ 20,567
BALANCE SHEETS DATA					
Property, Plant and Equipment	$ 1,445,133	$ 1,414,426	$ 1,367,138	$ 1,355,315	$ 1,301,332
Accumulated Depreciation and Amortization	442,778	425,817	398,608	382,022	373,874
Net Property, Plant and Equipment	$ 1,002,355	$ 988,609	$ 968,530	$ 973,293	$ 927,458
Total Assets	$ 1,310,565	$ 1,320,026	$ 1,243,247	$ 1,221,634	$ 1,188,342
Common Shareholder's Equity	$ 369,651	$ 347,841	$ 320,980	$ 317,138	$ 298,018
Long-term Debt (a)	$ 446,968	$ 486,990	$ 508,310	$ 487,602	$ 466,632
Obligations Under Capital Leases (a)	$ 2,647	$ 3,168	$ 4,363	$ 5,292	$ 7,248

(a) Including portion due within one year.

KENTUCKY POWER COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

As a public utility, we engage in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 176,000 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 relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold and relative peak demand changes. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR), which determines each member's percentage share of revenues and costs.

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

Prior to April 1, 2006, under the SIA, we shared revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management activities among AEP East companies and AEP West companies based on an allocation methodology established at the time of the AEP-CSW merger. Sharing in a calendar year was based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger. This activity resulted in an AEP East companies' and AEP West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year were also based upon the relative generating capacity of the AEP East companies and AEP West companies in the event the pre-merger activity level was exceeded. The capacity-based allocation mechanism was triggered in July 2005 and 2004, resulting in an allocation factor of approximately 70% and 30% for the AEP East companies and AEP West companies, respectively, for the remainder of each year.

Effective April 1, 2006, we base the allocation methodology of power and gas trading and marketing activities upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among the AEP East companies, PSO and SWEPCo in proportion to the marketing realization directly assigned to each zone for the current month plus the preceding eleven months. Management is unable to predict the ultimate effect on future results of operations and cash flows but expects an increase in margins accruing to the AEP East companies as a result of the SIA change. Our impact will also depend upon the level of future trading and marketing margins in PJM and MISO and sharing mechanisms with customers for off-system sales margins in Kentucky. The 2006 results of operations and cash flows reflect nine months of the SIA change.

AEPSC conducts power, gas and coal risk management activities on our behalf. We share in the revenues and expenses associated with these risk management activities with the other AEP East companies, PSO and SWEPCo. Power and gas risk management activities are allocated based on the existing power pool agreement and the SIA. We share in coal risk management activities based on our proportion of coal burned by the AEP System. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas and coal. The electricity, gas and coal contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. We settle the majority of the physical forward contracts by entering into offsetting contracts.

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

We 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 pursuant to the SIA.

Results of Operations

2006 Compared to 2005

Reconciliation of Year Ended December 31, 2005 to Year Ended December 31, 2006
Net Income
(in millions)

Year Ended December 31, 2005		$ 21
Changes in Gross Margin:		
Retail Margins	21	
Off-system Sales	13	
Transmission Revenues	(10)	
Other	4	
Total Change in Gross Margin		28
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(7)	
Depreciation and Amortization	(1)	
Taxes Other Than Income Taxes	1	
Total Change in Operating Expenses and Other		(7)
Income Tax Expense		(7)
Year Ended December 31, 2006		$ 35

Net Income increased $14 million to $35 million in 2006. The key driver of the increase was a $28 million increase in Gross Margin, partially offset by an increase in Other Operation and Maintenance expenses of $7 million and an increase in Income Tax Expense of $7 million.

The major components of our change in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins increased $21 million primarily due to rate relief of $33 million from the March 2006 approval of the settlement agreement in our base rate case. The above was partially offset by a $6 million decrease related to increased credits to retail customers of a portion of off-system sales margins due to higher off-system sales. Another partial offset is a result of increased capacity charges of $4 million due to changes in the relative peak demands and generating capacity of the AEP Power Pool members.
- Margins from Off-system Sales increased $13 million primarily due to a $12 million increase in physical sales margins and a $6 million increase in our allocation of off-system sales margins under the SIA, offset by a $5 million decrease in margins from optimization activities. The change in allocation methodology of the SIA occurred on April 1, 2006. See the "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 4.
- Transmission Revenues decreased $10 million primarily due to the elimination of SECA revenues as of April 1, 2006 and a provision of $3 million recorded in 2006 related to potential SECA refunds pending settlement negotiations with various intervenors. At this time, we have a pending proposal with the FERC to replace SECA revenues. See the "Transmission Rate Proceedings at the FERC" section of Note 4.
- Other revenues increased $4 million primarily due to a $3 million unfavorable adjustment of the Demand Side Management Program regulatory asset in March 2005.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased $7 million primarily due to maintenance of overhead lines as well as an increase in transmission costs associated with the Transmission Equalization

Agreement. This increase in transmission costs was due to the addition of the Wyoming-Jacksons Ferry 765 kV line which was energized and placed into service in June 2006.

Income Taxes

Income Tax Expense increased $7 million primarily due to an increase in pretax book income.

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 our Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes our contractual cash obligations at December 31, 2006:

Payment Due by Period
(in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Advances from Affiliates (a)	$ 30.6	$ -	$ -	$ -	$ 30.6
Interest on Fixed Rate Portion of Long-term Debt (b)	24.0	13.0	11.0	92.0	140.0
Fixed Rate Portion of Long-term Debt (c)	322.0	30.0	-	95.0	447.0
Capital Lease Obligations (d)	1.2	1.2	0.4	0.1	2.9
Noncancelable Operating Leases (d)	2.1	3.2	2.3	2.3	9.9
Fuel Purchase Contracts (e)	81.8	28.6	7.9	22.5	140.8
Energy and Capacity Purchase Contracts (f)	0.7	1.1	1.7	0.3	3.8
Construction Contracts for Capital Assets (g)	30.0	10.0	-	41.1	81.1
Total	$ 492.4	$ 87.1	$ 23.3	$ 253.3	$ 856.1

(a) Represents short-term borrowings from the Utility Money Pool.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2006 and do not reflect anticipated future refinancings, early redemptions or debt issuances.
(c) See Note 15. Represents principal only excluding interest.
(d) See Note 14.
(e) Represents contractual obligations to purchase coal and other consumables as fuel for electric generation along with related transportation of the fuel.
(f) Represents contractual cash flows of energy and capacity purchase contracts.
(g) Represents only capital assets that are contractual obligations.

As discussed in Note 9, our minimum pension funding requirements are not included above as such amounts are discretionary based upon the status of the trust.

As of December 31, 2006, we have no outstanding standby letters of credit or guarantees of performance.

Significant Factors

Big Sandy Plant Scrubber

Completion of construction of a scrubber at our Big Sandy Plant was previously scheduled for 2010. We suspended the project in the second quarter of 2006 after a generation engineering evaluation determined that there was a substantially higher estimated capital cost due to increases in labor and material costs, refinements of preliminary costs estimates and an increase in cost per ton of removed SO_2. We currently estimate the project to have an in-service date of 2014 or beyond. Management continues to review its emission compliance plans given changing market conditions and the evolving legislative and regulatory environment.

We transferred the total project expenditures of $17 million during 2006 from Construction Work in Progress to Deferred Charges and Other on our Balance Sheet. If management does not resume the project, the balance of incurred expenditures would negatively impact future earnings unless a regulatory asset could be established due to probable recovery through rates.

Litigation and Regulatory Activity

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. We do, however, assess the probability of loss for such contingencies and accrue a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our regulatory proceedings and pending litigation, see Note 4 - Rate Matters and Note 6 - Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect our results of operations, financial condition and cash flows.

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

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits 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

The following two tables summarize the various mark-to-market (MTM) positions included in our balance sheet as of December 31, 2006 and the reasons for changes in our total MTM value as compared to December 31, 2005.

Reconciliation of MTM Risk Management Contracts to Balance Sheet
As of December 31, 2006
(in thousands)

	MTM Risk Management Contracts	Cash Flow & Fair Value Hedges	DETM Assignment (a)	Total
Current Assets	$ 23,049	$ 2,575	$ -	$ 25,624
Noncurrent Assets	21,252	30	-	21,282
Total MTM Derivative Contract Assets	44,301	2,605	-	46,906
Current Liabilities	(18,302)	(1,126)	(573)	(20,001)
Noncurrent Liabilities	(13,301)	(6)	(2,119)	(15,426)
Total MTM Derivative Contract Liabilities	(31,603)	(1,132)	(2,692)	(35,427)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 12,698	$ 1,473	$ (2,692)	$ 11,479

(a) See "Natural Gas Contracts with DETM" section of Note 16.

MTM Risk Management Contract Net Assets
Year Ended December 31, 2006
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2005	$ 13,518
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(225)
Fair Value of New Contracts at Inception When Entered During the Period (a)	-
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period	(62)
Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts	-
Changes in Fair Value Due to Market Fluctuations During the Period (b)	(553)
Changes Due to SIA Agreement (c)	(1,565)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	1,585
Total MTM Risk Management Contract Net Assets	12,698
Net Cash Flow & Fair Value Hedge Contracts	1,473
DETM Assignment (e)	(2,692)
Total MTM Risk Management Contract Net Assets at December 31, 2006	$ 11,479

(a) Reflects fair value on long-term contracts which are typically with customers that seek fixed pricing 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.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.

(c) See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 4.
(d) "Changes in Fair Value 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.
(e) See "Natural Gas Contracts with DETM" section of Note 16.

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

The following table presents:

- The method of measuring 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 to give 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, 2006
(in thousands)

	2007	2008	2009	2010	2011	After 2011	Total
Prices Actively Quoted - Exchange Traded Contracts	$ 1,281	$ 917	$ 155	$ -	$ -	$ -	$ 2,353
Prices Provided by Other External Sources - OTC Broker Quotes (a)	3,820	1,243	1,804	-	-	-	6,867
Prices Based on Models and Other Valuation Methods (b)	(355)	210	926	2,070	273	354	3,478
Total	$ 4,746	$ 2,370	$ 2,885	$ 2,070	$ 273	$ 354	$ 12,698

(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.

Contract values that are measured using models or valuation methods other than active quotes or OTC broker quotes (because of the lack of such data for all delivery quantities, locations and periods) incorporate in the model or other valuation methods, to the extent possible, OTC broker quotes and active quotes for deliveries in years and at locations for which such quotes are available.

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 use various commodity instruments designated in qualifying cash flow hedge strategies to mitigate the impact of these fluctuations on the future cash flows. We do not hedge all commodity price risk.

We use interest rate derivative transactions to manage interest rate risk related to anticipated borrowings of fixed-rate debt. We do not hedge all interest rate risk.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Balance Sheets and the reasons for the changes from December 31, 2005 to December 31, 2006. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Year Ended December 31, 2006
(in thousands)

	Power	Interest Rate	Total
Beginning Balance in AOCI December 31, 2005	$ (352)	$ 158	$ (194)
Changes in Fair Value	1,295	201	1,496
Impact due to Changes in SIA (a)	(106)	-	(106)
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	442	(86)	356
Ending Balance in AOCI December 31, 2006	$ 1,279	$ 273	$ 1,552

(a) See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 4.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $1,340 thousand gain.

Credit Risk

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

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at December 31, 2006, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

December 31, 2006 (in thousands)				December 31, 2005 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$181	$459	$158	$86	$174	$289	$138	$50

The High VaR for the twelve months ended December 31, 2006 occurred in the third quarter due to volatility in the ECAR/PJM region.

VaR Associated with Debt Outstanding

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. 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 $13 million at December 31, 2006 and 2005. 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, 2006, 2005 and 2004
(in thousands)

	2006	2005	2004
REVENUES			
Electric Generation, Transmission and Distribution	$ 526,432	$ 458,858	$ 397,581
Sales to AEP Affiliates	58,287	70,803	48,717
Other	1,148	1,682	2,663
TOTAL	585,867	531,343	448,961
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	152,335	142,672	103,881
Purchased Electricity for Resale	8,724	7,213	3,407
Purchased Electricity from AEP Affiliates	192,080	176,350	140,758
Other Operation	60,674	59,024	51,782
Maintenance	35,430	30,652	32,802
Depreciation and Amortization	46,387	45,110	43,847
Taxes Other Than Income Taxes	8,612	9,491	9,145
TOTAL	504,242	470,512	385,622
OPERATING INCOME	81,625	60,831	63,339
Other Income (Expense):			
Interest Income	656	880	462
Allowance for Equity Funds Used During Construction	241	305	245
Interest Expense	(28,832)	(29,071)	(29,470)
INCOME BEFORE INCOME TAXES	53,690	32,945	34,576
Income Tax Expense	18,655	12,136	8,671
NET INCOME	$ 35,035	$ 20,809	$ 25,905

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, 2006, 2005 and 2004
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
Common Stock Dividends			(2,500)		(2,500)
TOTAL					318,480
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $542				(1,007)	(1,007)
Minimum Pension Liability, Net of Tax of $5,147				9,559	9,559
NET INCOME			20,809		20,809
TOTAL COMPREHENSIVE INCOME					29,361
DECEMBER 31, 2005	50,450	208,750	88,864	(223)	347,841
Common Stock Dividends			(15,000)		(15,000)
TOTAL					332,841
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $940				1,746	1,746
Minimum Pension Liability, Net of Tax of $16				29	29
NET INCOME			35,035		35,035

TOTAL COMPREHENSIVE INCOME					36,810
DECEMBER 31, 2006	$ 50,450	$ 208,750	$ 108,899	$ 1,552	$369,651

See Notes to Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY
BALANCE SHEETS
ASSETS
December 31, 2006 and 2005
(in thousands)

	2006	2005
CURRENT ASSETS		
Cash and Cash Equivalents	$ 702	$ 526
Accounts Receivable:		
Customers	30,112	26,533
Affiliated Companies	10,540	23,525
Accrued Unbilled Revenues	3,602	6,311
Miscellaneous	327	35
Allowance for Uncollectible Accounts	(227)	(147)
Total Accounts Receivable	44,354	56,257
Fuel	16,070	8,490
Materials and Supplies	8,726	10,181
Risk Management Assets	25,624	31,437
Accrued Tax Benefits	1,021	6,598
Margin Deposits	2,923	6,895
Prepayments and Other	2,425	6,324
TOTAL	101,845	126,708
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	478,955	472,575
Transmission	394,419	386,945
Distribution	481,083	456,063
Other	61,089	63,382
Construction Work in Progress	29,587	35,461
Total	1,445,133	1,414,426
Accumulated Depreciation and Amortization	442,778	425,817
TOTAL - NET	1,002,355	988,609
OTHER NONCURRENT ASSETS		
Regulatory Assets	136,139	117,432
Long-term Risk Management Assets	21,282	41,810
Deferred Charges and Other	48,944	45,467
TOTAL	206,365	204,709
TOTAL ASSETS	$ 1,310,565	$ 1,320,026

See Notes to Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY
BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
December 31, 2006 and 2005

	2006	2005
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 30,636	$ 6,040
Accounts Payable:		
General	31,490	32,454
Affiliated Companies	23,658	29,326
Long-term Debt Due Within One Year - Nonaffiliated	322,048	-
Long-term Debt Due Within One Year - Affiliated	-	39,771
Risk Management Liabilities	20,001	28,770
Customer Deposits	16,095	21,643
Accrued Taxes	18,775	8,805
Other	26,303	21,524
TOTAL	489,006	188,333
NONCURRENT LIABILITIES		
Long-term Debt - Nonaffiliated	104,920	427,219
Long-term Debt - Affiliated	20,000	20,000
Long-term Risk Management Liabilities	15,426	35,302
Deferred Income Taxes	242,133	234,719
Regulatory Liabilities and Deferred Investment Tax Credits	49,109	56,794
Deferred Credits and Other	20,320	9,818
TOTAL	451,908	783,852
TOTAL LIABILITIES	940,914	972,185
Commitments and Contingencies (Note 6)		
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	108,899	88,864
Accumulated Other Comprehensive Income (Loss)	1,552	(223)
TOTAL	369,651	347,841
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 1,310,565	$ 1,320,026

See Notes to Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2006, 2005 and 2004
(in thousands)

	2006	2005	2004
OPERATING ACTIVITIES			
Net Income	$ 35,035	$ 20,809	$ 25,905
Adjustments for Noncash Items:			
Depreciation and Amortization	46,387	45,110	43,847
Deferred Income Taxes	2,596	10,555	12,774
Mark-to-Market of Risk Management Contracts	580	(3,465)	1,020
Pension Contributions to Qualified Plan Trusts	-	(18,894)	(451)
Change in Other Noncurrent Assets	(4,738)	(419)	(6,902)
Change in Other Noncurrent Liabilities	2,621	3,844	9,126
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	11,903	(3,681)	(1,177)
Fuel, Materials and Supplies	(6,125)	(2,735)	2,724
Accounts Payable	(3,436)	13,184	(1,745)
Customer Deposits	(5,548)	9,334	2,415
Accrued Taxes, Net	15,547	(7,041)	1,919
Other Current Assets	7,867	(9,261)	474
Other Current Liabilities	3,953	1,589	65
Net Cash Flows From Operating Activities	106,642	58,929	89,994
INVESTING ACTIVITIES			
Construction Expenditures	(77,848)	(56,979)	(36,957)
Change in Other Cash Deposits, Net	5	(5)	-
Change in Advances to Affiliates, Net	-	16,127	(16,127)
Proceeds from Sales of Assets	2,956	300	1,538
Net Cash Flows Used For Investing Activities	(74,887)	(40,557)	(51,546)
FINANCING ACTIVITIES			
Issuance of Long-term Debt - Affiliated	-	-	20,000
Change in Advances from Affiliates, Net	24,596	6,040	(38,096)
Retirement of Long-term Debt - Affiliated	(40,000)	(20,000)	-
Principal Payments for Capital Lease Obligations	(1,175)	(1,518)	(1,605)
Dividends Paid on Common Stock	(15,000)	(2,500)	(19,501)
Net Cash Flows Used For Financing Activities	(31,579)	(17,978)	(39,202)
Net Increase (Decrease) in Cash and Cash Equivalents	176	394	(754)
Cash and Cash Equivalents at Beginning of Period	526	132	886
Cash and Cash Equivalents at End of Period	$ 702	$ 526	$ 132
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 27,887	$ 27,354	$ 28,367
Net Cash Paid (Received) for Income Taxes	11,516	11,655	(3,233)
Noncash Acquisitions Under Capital Leases	648	419	925
Construction Expenditures Included in Accounts Payable at December 31,	3,357	6,553	2,936

See Notes to Financial Statements of Registrant Subsidiaries.

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 (the "Company") as of December 31, 2006 and 2005, 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, 2006. 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Kentucky Power Company as of December 31, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Notes 2 and 9 to the financial statements, respectively, the Company adopted FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans,"effective December 31, 2006, 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, 2007