Control Number: 18661

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PUBLIC UTILITY COMMISSION OF TEXAS

Control No. 18661

Substantive Rule 25.73(c)

For The Quarter Ending March 31, 2005

For

American Electric Power Company, Inc.
AEP Generating Company
AEP Texas Central Company
AEP Texas North Company
Appalachian Power Company
Columbus Southern Power Company
Indiana Michigan Power Company
Kentucky Power Company
Ohio Power Company
Public Service Company of Oklahoma
Southwestern Electric Power Company

May 5, 2005

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended **March 31, 2005**
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Transition Period from ____ to ____

Commission File Number	Registrant, State of Incorporation, Address of Principal Executive Offices, and Telephone Number	I.R.S. Employer Identification No.
1-3525	AMERICAN ELECTRIC POWER COMPANY, INC. (A New York Corporation)	13-4922640
0-18135	AEP GENERATING COMPANY (An Ohio Corporation)	31-1033833
0-346	AEP TEXAS CENTRAL COMPANY (A Texas Corporation)	74-0550600
0-340	AEP TEXAS NORTH COMPANY (A Texas Corporation)	75-0646790
1-3457	APPALACHIAN POWER COMPANY (A Virginia Corporation)	54-0124790
1-2680	COLUMBUS SOUTHERN POWER COMPANY (An Ohio Corporation)	31-4154203
1-3570	INDIANA MICHIGAN POWER COMPANY (An Indiana Corporation)	35-0410455
1-6858	KENTUCKY POWER COMPANY (A Kentucky Corporation)	61-0247775
1-6543	OHIO POWER COMPANY (An Ohio Corporation)	31-4271000
0-343	PUBLIC SERVICE COMPANY OF OKLAHOMA (An Oklahoma Corporation)	73-0410895
1-3146	SOUTHWESTERN ELECTRIC POWER COMPANY (A Delaware Corporation)	72-0323455

All Registrants 1 Riverside Plaza, Columbus, Ohio 43215-2373
Telephone (614) 716-1000

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.

Yes _X_ NO ___

Indicate by check mark whether American Electric Power Company, Inc. is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Yes _X_ NO ___

Indicate by check mark whether AEP Generating Company, AEP Texas Central Company, AEP Texas North Company, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company, are accelerated filers (as defined in Rule 12b-2 of the Exchange Act).

*Yes ___ NO _X_*

AEP Generating Company, AEP Texas North Company, Columbus Southern Power Company, Kentucky Power Company and Public Service Company of Oklahoma meet the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and are therefore filing this Form 10-Q with the reduced disclosure format specified in General Instruction H(2) to Form 10-Q.

	Number of Shares of Common Stock Outstanding at April 29, 2005
American Electric Power Company, Inc.	384,020,319
AEP Generating Company	1,000
AEP Texas Central Company	2,211,678
AEP Texas North Company	5,488,560
Appalachian Power Company	13,499,500
Columbus Southern Power Company	16,410,426
Indiana Michigan Power Company	1,400,000
Kentucky Power Company	1,009,000
Ohio Power Company	27,952,473
Public Service Company of Oklahoma	9,013,000
Southwestern Electric Power Company	7,536,640

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX TO QUARTERLY REPORT ON FORM 10-Q
March 31, 2005

This combined Form 10-Q is separately filed by American Electric Power Company, Inc., AEP Generating Company, AEP Texas Central Company, AEP Texas North Company, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Each registrant makes no representation as to information relating to the other registrants.

GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an electric utility subsidiary of AEP.
AEP or Parent	American Electric Power Company, Inc.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated domestic electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEPES	AEP Energy Services, Inc., a subsidiary of AEP Resources, Inc.
AEP System or the System	The American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP System Power Pool or AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEP West companies	PSO, SWEPCo, TCC and TNC.
ALJ	Administrative Law Judge.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ARO	Asset Retirement Obligations.
CAA	The Clean Air Act.
Cook Plant	The Donald C. Cook Nuclear Plant, a two-unit, 2,110 MW nuclear plant owned by I&M.
COLI	Corporate owned, life insurance program.
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.
DOE	United States Department of Energy.
ECAR	East Central Area Reliability Council.
EITF	The Financial Accounting Standards Board's Emerging Issues Task Force.
ERCOT	The Electric Reliability Council of Texas.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN 46	FASB Interpretation No. 46, "Consolidation of Variable Interest Entities."
GAAP	Generally Accepted Accounting Principles.
HPL	Houston Pipeline Company.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IPP	Independent Power Producers.
IURC	Indiana Utility Regulatory Commission.
JMG	JMG Funding LP.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
KWH	Kilowatthour.
LIG	Louisiana Intrastate Gas, a former AEP subsidiary.
ME SWEPCo	Mutual Energy SWEPCo L.P., a Texas retail electric provider.

MLR	Member load ratio, the method used to allocate AEP Power Pool transactions to its members.
MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NO_x	Nitrogen oxide.
Nonutility Money Pool	AEP System's Nonutility Money Pool.
OATT	Open Access Transmission Tariff.
OCC	Oklahoma Corporation Commission.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OTC	Over the counter.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utility Commission of Ohio
PUCT	The Public Utility Commission of Texas.
PUHCA	Public Utility Holding Company Act.
PURPA	The Public Utility Regulatory Policies Act of 1978.
Registrant Subsidiaries	AEP subsidiaries who are SEC registrants; AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC.
REP	Texas Retail Electric Provider.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana owned by AEGCo and I&M.
RTO	Regional Transmission Organization.
S&P	Standard and Poor's.
SEC	United States Securities and Exchange Commission.
SECA	Seams Elimination Cost Allocation.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SFAS 109	Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes.
SFAS 133	Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities.
SNF	Spent Nuclear Fuel.
SPP	Southwest Power Pool.
STP	South Texas Project Nuclear Generating Plant, owned 25.2% by TCC.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
Tenor	Maturity of a contract.
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
True-up Proceeding	A filing to be made under the Texas Restructuring Legislation to finalize the amount of stranded costs and other true-up items and the recovery of such amounts.
TVA	Tennessee Valley Authority.
Utility Money Pool	AEP System's Utility Money Pool.
VaR	Value at Risk, a method to quantify risk exposure.
Virginia SCC	Virginia State Corporation Commission.
Zimmer Plant	William H. Zimmer Generating Station, a 1,300 MW coal-fired unit owned 25.4% by CSPCo.

FORWARD-LOOKING INFORMATION

This report made by AEP and its Registrant Subsidiaries contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- Electric load and customer growth.
- Weather conditions, including storms.
- Available sources and costs of, and transportation for, fuels and the creditworthiness of fuel suppliers and transporters.
- Availability of generating capacity and the performance of our generating plants.
- The ability to recover regulatory assets and stranded costs in connection with deregulation.
- The ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- New legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon and other substances.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery for new investments, transmission service and environmental compliance).
- Oversight and/or investigation of the energy sector or its participants.
- Resolution of litigation (including pending Clean Air Act enforcement actions and disputes arising from the bankruptcy of Enron Corp.).
- Our ability to constrain operation and maintenance costs.
- Our ability to sell assets at acceptable prices and other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale.
- The economic climate and growth in our service territory and changes in market demand and demographic patterns.
- Inflationary trends.
- Our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities.
- Changes in the creditworthiness and number of participants in the energy trading market.
- Changes in the financial markets, particularly those affecting the availability of capital and our ability to refinance existing debt at attractive rates.
- Actions of rating agencies, including changes in the ratings of debt.
- Volatility and changes in markets for electricity, natural gas and other energy-related commodities.
- Changes in utility regulation, including membership and integration into regional transmission structures.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- The performance of our pension and other postretirement benefit plans.
- Prices for power that we generate and sell at wholesale.
- Changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

EXECUTIVE OVERVIEW

Utility Operations Segment Results

Net income from Utility Operations was $353 million for the first quarter of 2005, representing an increase of $49 million. This increase over first quarter 2004 was partially due to payments totaling $115 million received in March 2005 from Centrica related to the earnings sharing agreement as stipulated in the purchase and sale agreement from the sale of our Texas Retail Electric Providers (REPs) in 2002. The payments received related to 2002, 2003 and 2004. We expect to receive and recognize additional earnings sharing payments in 2006 and 2007 related to 2005 and 2006 activity, respectively. The earnings sharing payments for 2005 and 2006 are capped at $70 million and $20 million, respectively. However, all payments are contingent on the operating results of Centrica. Therefore, receipt of payments for future activity is not assured.

Additional increases in first quarter 2005 included $45 million related to regulatory assets established by our Ohio companies for fulfilling our Provider of Last Resort obligations, for which the PUCO authorized recovery in its approval of our Rate Stabilization Plans in January 2005.

Partially offsetting these two favorable items is an unfavorable variance of $50 million related to higher delivered fuel costs, as further discussed below in the "Fuel Costs" section, and $31 million related to reduced margins on transmission revenues.

Divestiture Proceeds

We sold a 98% share of our Houston Pipe Line Company (HPL) in January 2005 for approximately $1 billion. In March 2005, we used the cash proceeds to repurchase 12.5 million shares of our common stock in a share repurchase transaction at an initial share price of $34.63 per share and on April 15, 2005 we redeemed $550 million of our senior notes. These activities continue to emphasize our focus on strengthening our balance sheet and reducing debt at the parent company level.

Environmental

On March 10, 2005, the Federal EPA released the Clean Air Interstate Rule (CAIR), which further limits emissions of sulfur dioxide and nitrogen oxides and sets new limits on power plant emissions associated with soot, smog and acid rain in the eastern half of the United States. It is likely that we will add nine new flue gas desulphurization units (FGDs) and three selective catalytic reactors (SCRs) to our eastern fleet in order to meet existing requirements as well as the tighter requirements of the new rule. FGDs currently are installed and operating at four east and two west plants and are under construction at three east plants.

On March 15, 2005, the Federal EPA released its final rule on mercury emissions from power plants, which would allow a cap-and-trade system. The cap-and-trade system creates incentives for continued development and testing of promising mercury control technologies and, by making the mercury emissions a tradable commodity, the new system provides a strong motivation to make early emission reductions and for continuous improvements in control technologies. The installation of SCRs and FGDs at a facility have the co-benefit of mercury capture.

We are currently developing an estimate of additional costs to comply with the newly issued rules. Accordingly, we have not yet changed our previously announced plans related to capital investment amounts of $3.7 billion through 2010 and $5 billion through 2020. We continue to support our investment program through the use of free cash flow and rate increases and therefore, do not anticipate material incremental leveraging.

Texas Regulatory Activity

Stranded Cost Recovery

In February 2005, TCC filed with the PUCT requesting a good cause exception to the true-up rule to allow TCC to make its true-up filing prior to the closing of the sale of TCC's ownership interest in Oklaunion. The asset sales pending are our Oklaunion and STP interests. The sale of TCC's interest in STP should be completed in the first half of 2005, subject to obtaining the necessary regulatory approvals. There are likely to be delays in resolving rights of first refusal issues and related litigation with a third party affecting Oklaunion.

TCC Rate Case
Hearings were held on the affiliated transactions remand issue in March 2005. The PUCT deferred ruling on the allowable amount of TCC affiliate transactions. See the "Significant Matters - TCC Rate Case" section below for further discussion.

<u>Fuel Costs</u>
Market prices for coal, natural gas and oil increased dramatically during 2004. These increasing fuel costs are the result of increasing worldwide demand, supply uncertainty, and transportation constraints, as well as other market factors. We manage price and performance risk, particularly for coal, through a portfolio of contracts of varying durations and other fuel procurement and management activities. We have fuel recovery mechanisms for about 50% of our fuel costs in our various jurisdictions. Additionally, about 20% of our fuel is used for off-system sales where prices we receive for our power sales should recover our cost of fuel. Accordingly, approximately 70% of fuel cost increases are recovered. The remaining 30% of our fuel costs relate to Ohio and West Virginia customers, where we do not have a fuel cost recovery mechanism. During the first quarter of 2005, higher delivered coal costs reduced gross margins by approximately $50 million. We currently have 100% and 88% of our projected coal needs committed for 2005 and 2006, respectively.

<u>New Technology Plant</u>
Our plans to construct synthetic-gas-fired plant(s) in the next five to six years utilizing integrated gasification combined cycle (IGCC) technology continued to progress. During the first quarter of 2005, three important regulatory filings were made.

On February 10, 2005, we asked PJM to evaluate transmission interconnection feasibility for three potential sites currently under consideration for the plant(s). Those sites include Mason County, West Virginia, Meigs County, Ohio, and Lewis County, Kentucky. The filing with PJM will begin feasibility studies to determine the transmission network upgrades and estimated cost needed at each site to connect a new plant to the existing transmission grid.

On March 15, 2005, APCo notified the Public Service Commission of West Virginia of its intent to file for a Certificate of Public Convenience and Necessity, reflecting APCo's need for new generating capacity to meet the growing demand for electricity and to ensure a reliable supply of electricity for its customers.

On March 18, 2005, CSPCo and OPCo filed an application with the PUCO seeking authority to recover costs related to the construction and operation of an IGCC plant. This filing followed a suggestion by the PUCO in its January 2005 Rate Stabilization Plan order that CSPCo and OPCo proceed with this construction.

<u>Additional Information</u>
For additional information on our strategic outlook, see "Management's Financial Discussion and Analysis of Results of Operations," including "Business Strategy," in our 2004 Annual Report. Also see the remainder of our "Management's Financial Discussion and Analysis of Results of Operations" in this Form 10-Q, along with the Notes to Consolidated Financial Statements.

RESULTS OF OPERATIONS

<u>Segments</u>

Our principal operating business segments and their major activities are:

- **Utility Operations:**
    - Domestic generation of electricity for sale to retail and wholesale customers.
    - Domestic electricity transmission and distribution.

- **Investments-Gas Operations** (a)
  - Gas pipeline and storage services.
  - Gas marketing and risk management activities.

- **Investments-UK Operations** (b)
  - Generation of electricity in the U.K. for sale to wholesale customers.
  - Coal procurement and transportation to our plants.

- **Investments-Other:** (c)
  - Bulk commodity barging operations, wind farms, independent power producers and other energy supply related businesses.

(a) LIG Pipeline Company and its subsidiaries, including Jefferson Island Storage & Hub LLC, were classified as discontinued operations during 2003 and were sold during 2004. We sold a 98% interest in HPL during the first quarter of 2005.
(b) UK Operations were classified as discontinued operations during 2003 and were sold during the third quarter of 2004.
(c) Four independent power producers were sold during the third and fourth quarter of 2004.

AEP Consolidated Results

Our consolidated Net Income for the three-month periods ended March 31, 2005 and 2004 was as follows (Earnings and Weighted Average Shares Outstanding in millions):

	2005		2004	
	Earnings	**EPS**	**Earnings**	**EPS**
Utility Operations	$ 353	$ 0.90	$ 304	$ 0.77
Investments – Gas Operations	10	0.03	(10)	(0.03)
Investments – Other	5	0.01	4	0.01
All Other (a)	(14)	(0.04)	(9)	(0.02)
Income Before Discontinued Operations	354	0.90	289	0.73
Investments – Gas Operations	-	-	(1)	-
Investments – UK Operations	(5)	(0.01)	(12)	(0.04)
Investments – Other	6	0.01	6	0.02
Discontinued Operations, Net of Tax	1	-	(7)	(0.02)
Net Income	$ 355	$ 0.90	$ 282	$ 0.71
Weighted Average Shares Outstanding		393		395

(a) All Other includes the parent company's interest income and expense, as well as other nonallocated costs.

First Quarter of 2005 Compared to First Quarter of 2004

Income Before Discontinued Operations increased $65 million to $354 million in the first quarter of 2005 compared to the first quarter of 2004.

For the first quarter of 2005, our Utility Operations earnings increased $49 million from the previous year driven primarily by the Centrica earnings sharing and Ohio carrying cost accruals somewhat offset by higher fuel costs and milder weather in the winter months of 2005.

Earnings from our Gas Operations increased $20 million from the previous year reflecting favorable results for one month of HPL's operations in 2005 rather than three months in the prior year due to the sale of the HPL assets in January 2005, which resulted in decreased operations, maintenance and depreciation expenses as well as decreased interest charges.

The loss from our All Other grouping, primarily representing parent company income and expenses, increased $5 million in 2005. This increase is primarily due to lower interest income and lower guarantee fees received in the current period.

Average shares outstanding decreased to 393 million in 2005 from 395 in 2004 primarily due to the common stock share repurchase program approved by our Board of Directors in February 2005.

Our results of operations by operating segment are discussed below.

Utility Operations

	Three Months Ended March 31,	
	2005	2004
	(in millions)	
Revenues	$ 2,614	$ 2,602
Fuel and Purchased Power	905	779
Gross Margin	1,709	1,823
Depreciation and Amortization	318	310
Other Operating Expenses	871	888
Operating Income	520	625
Other Income (Expense), Net	148	9
Interest Expenses and Preferred Stock Dividend Requirements	144	166
Income Taxes	171	164
Income Before Discontinued Operations	$ 353	$ 304

Summary of Selected Sales Data
For Utility Operations
For the Three Months Ended March 31, 2005 and 2004

	2005	2004
Energy Summary	(in millions of KWH)	
Retail:		
Residential	13,224	13,427
Commercial	8,732	8,779
Industrial	12,774	12,273
Miscellaneous	645	743
Subtotal	35,375	35,222
Texas Retail and Other	228	224
Total	35,603	35,446
Wholesale	12,635	13,851
Texas Wires Delivery	5,519	5,490

Weather Summary	2005	2004
	(in degree days)	
Eastern Region		
Actual – Heating	1,774	1,864
Normal – Heating (a)	1,811	1,806
Actual – Cooling	-	3
Normal – Cooling (a)	3	3
Western Region (b)		
Actual – Heating	769	883
Normal – Heating (a)	973	978
Actual – Cooling	20	30
Normal – Cooling (a)	18	17

(a) Normal Heating/Cooling represents the 30-year average of degree days.
(b) Western Region statistics represent PSO/SWEPCo customer base only.

First Quarter of 2005 Compared to First Quarter of 2004

Reconciliation of First Quarter of 2004 to First Quarter of 2005
Income Before Discontinued Operations
(in millions)

First Quarter of 2004		$ 304
Changes in Gross Margin:		
Retail Margins	(60)	
Texas Supply	(20)	
Transmission Revenues	(31)	
Off-system Sales	(7)	
Other Revenues	4	
		(114)
Changes in Operating Expenses And Other:		
Maintenance and Other Operation	21	
Depreciation and Amortization	(8)	
Taxes Other Than Income Taxes	(4)	
Other Income (Expense), Net	139	
Interest Expenses	22	
		170
Income Taxes		(7)
First Quarter of 2005		$ 353

Income from Utility Operations increased $49 million to $353 million in 2005. The key drivers of the increase were a $139 million increase in other income (expense), net and a $31 million net decrease in operating expenses and other partially offset by a $114 million decrease in gross margin and a $7 million increase in income tax expense.

The major components of our change in gross margin, defined as utility revenues net of related fuel and purchased power, were as follows:

- Overall retail margins in our utility business were $60 million lower than last year. The primary driver of this decrease was higher delivered fuel costs of approximately $50 million, of which $25 million relates to our Ohio jurisdiction, $16 million relates to APCo and $6 million relates to I&M.
- Our Texas supply business had a $20 million decrease in gross margin as a result of decreased generation due to the sale of a majority of our Texas generation assets in the third quarter of 2004.
- Margins from transmission revenues decreased $31 million primarily due to the loss of through and out rates as mandated by the FERC.
- Margins from off-system sales for 2005 were $7 million lower than 2004 primarily due to lower optimization activity of $31 million partially offset by a $24 million increase in revenues due to a 5% increase in sales volumes.

Utility Operating Expenses and Other changed between years as follows:

- Maintenance and Other Operation expenses decreased $21 million. Overall, the decrease is due to timing and different spending patterns experienced in the first quarter of 2005 as compared to the same period in 2004. Additionally, benefit expenses were lower by $23 million primarily due to the cancellation of our corporate-owned life insurance (COLI) policies in 2005. These favorable variances were partially offset by storm expenses of $19 million related to a major ice storm in January 2005, primarily in our Indiana and Ohio jurisdictions.
- Other Income (Expense), Net increased $139 million primarily due to the following:
    - $112 million related to the $115 million payment received in March 2005 for the Centrica earnings sharing, which represents receipt of revenues related to the earnings sharing agreement with Centrica as stipulated in the purchase and sale agreement from the sale of our REPs in 2002. Agreement was reached with Centrica in March 2005 resolving disputes on how such amounts are to be calculated.
    - $26 million related to the accrual of carrying costs on environmental and RTO expenses by our Ohio companies related to the Rate Stabilization Plans.
- Interest Expenses decreased $22 million due to the refinancing of higher coupon debt and the retirement of debt in 2004 and in the first quarter of 2005.

See "Income Taxes" section below for discussion of fluctuations related to income taxes.

Investments-Gas Operations

First Quarter of 2005 Compared to First Quarter of 2004

Our $10 million net income from Gas Operations before discontinued operations compares with a $10 million loss recorded in the first quarter of 2004. Due to the sale of the HPL assets in January 2005, current year results include only one month of HPL's operations compared to three months of HPL's operations in the prior year. Approximately $14 million of the $20 million variance relates to a decrease in operation, maintenance and depreciation expenses and $5 million relates to a decrease in interest charges.

Investments – UK Operations

First Quarter of 2005 Compared to First Quarter of 2004

Losses from our Investments – UK Operations segment (all classified as Discontinued Operations) were $5 million in 2005 as compared to $12 million in 2004 due to the sale of substantially all operations and assets within our Investments – UK Operations segment in July 2004. The current period amount represents purchase price true-up adjustments made during the first quarter of 2005 related to the sale in 2004.

Investments – Other

First Quarter of 2005 Compared to First Quarter of 2004

Income before discontinued operations from our Investments – Other segment increased by $1 million in 2005 primarily due to the following:

- A $5 million increase at CSW Energy Services related to a current year gain due to a working capital true-up of the Numanco sale that occurred in November 2004 and a release of product liability and litigation reserves related to our Total Electric Vehicle investment due to the resolution of all open litigation as of March 31, 2005.
- A $3 million increase at AEP Communications due to debt being moved to the parent in October 2004.
- A $3 million increase at AEP Investments due to the investment write-down of PHPK Technologies, Inc. in 2004 of $1 million and favorable earnings from Pac Hydro of $2 million in 2005.
- A $3 million increase at CSW International related to tax reserve adjustments in March 2005.
- A $13 million decrease at AEP Resources related to a $2 million favorable judgment on an Australian tax issue received in 2004, a $4 million entry in 2004 related to capitalized fuel during construction of the Dow Plant, $3 million of losses related to the Dow plant in 2005 and a tax adjustment of $3 million booked in 2005.
- A $3 million decrease at our IPPs resulting from the sale of four of our IPPs in mid-2004.

All Other

First Quarter of 2005 Compared to First Quarter of 2004

Our parent company's loss for the first quarter of 2005 increased $5 million in comparison to the first quarter of 2004 due to lower interest income of $2 million and lower guarantee fees received of $1 million.

Income Taxes

The effective tax rates for the first quarter of 2005 and 2004 were 32.7% and 35.9%, 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, permanent differences, energy production credits, amortization of investment tax credits and state income taxes. The decrease in the effective tax rate is primarily due to changes in permanent differences including COLI and lower state income taxes.

FINANCIAL CONDITION

We measure our financial condition by the strength of our balance sheet and the liquidity provided by our cash flows.

Capitalization ($ in millions)

	March 31, 2005		December 31, 2004	
Common Shareholders' Equity	$ 8,268	39.9 %	$ 8,515	40.6 %
Cumulative Preferred Stock	61	0.3	61	0.3
Cumulative Preferred Stock (Subject to Mandatory Redemption)	-	-	66	0.3
Long-term Debt, including amounts due within one year	12,359	59.7	12,287	58.7
Short-term Debt	19	0.1	23	0.1
Total Capitalization	$ 20,707	100.0 %	$ 20,952	100.0 %

In March 2005, we repurchased 12.5 million shares of our outstanding common stock through an accelerated share repurchase agreement at an initial price of $34.63 per share. The 12.5 million shares repurchased under the program are subject to a future contingent purchase price adjustment based on the actual purchase prices paid for the common stock during the program period. Based on this adjustment, an asset of $2 million is reflected in Accounts Receivable on our Consolidated Balance Sheets as of March 31, 2005 due to the fact that the actual stock purchase prices were less than our initial payment.

As a consequence of the capital changes during the first quarter of 2005, our ratio of debt to total capital increased from 59.1% to 59.8% (preferred stock subject to mandatory redemption is included in the debt component of the ratio).

In April 2005, we reduced our ratio of debt to total capital through the redemption of $550 million of parent company senior notes.

Liquidity

Liquidity, or access to cash, is an important factor in determining our financial stability. We are committed to preserving an adequate liquidity position.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. We had an available liquidity position, at March 31, 2005, of approximately $4 billion as illustrated in the table below.

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$ 1,000	May 2007
Revolving Credit Facility	1,500	March 2010
Letter of Credit Facility	200	September 2006
Total	2,700	
Cash and Cash Equivalents	1,261	
Total Liquidity Sources	3,961	
Less: AEP Commercial Paper Outstanding	-(a)	
Letters of Credit Outstanding	50	
Net Available Liquidity at March 31, 2005	$ 3,911	

(a) Amount does not include JMG commercial paper outstanding in the amount of $19 million. This commercial paper is specifically associated with the Gavin scrubber and does not reduce AEP's available liquidity. The JMG commercial paper is supported by a separate letter of credit facility not included above.

Debt Covenants and Borrowing Limitations

Our revolving credit agreements contain certain covenants and require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating our outstanding debt and other capital is contractually defined. At March 31, 2005, this percentage was 55%. Nonperformance of these covenants could result in an event of default under these credit agreements. At March 31, 2005, we complied with the covenants contained in these credit agreements. In addition, the acceleration of our payment obligations, or the obligations of certain of our subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million would cause an event of default under these credit agreements and permit the lenders to declare the amounts outstanding thereunder payable.

Our revolving credit facilities generally prohibit new borrowings if we experience a material adverse change in our business or operations. We may, however, make new borrowings under these facilities if we experience a material adverse change so long as the proceeds of such borrowings are used to repay outstanding commercial paper. Under the $1.5 billion revolving credit facility, which matures in March 2010, we may borrow despite a material adverse change if our ratings are BBB (or better) from Standard and Poor's (S&P), and Baa2 (or better) from Moody's at any time during the facility's term.

Under an SEC order, we and our utility subsidiaries cannot incur additional indebtedness if the issuer's common equity would constitute less than 30% (25% for TCC) of its capital. In addition, this order restricts us and our utility subsidiaries from issuing long-term debt unless that debt will be rated investment grade by at least one nationally recognized statistical rating organization. At March 31, 2005, we were in compliance with this order.

Nonutility Money Pool borrowings, Utility Money Pool borrowings and external borrowings may not exceed SEC or state commission authorized limits. At March 31, 2005, we had not exceeded the SEC or state commission authorized limits.

Credit Ratings

AEP's ratings have not been adjusted by any rating agency during 2005 and AEP, Inc. is currently on a "positive" outlook by Moody's.

Our current ratings by the major agencies are as follows:

	Moody's	S&P	Fitch
Short-term Debt	P-3	A-2	F-2
Senior Unsecured Debt	Baa3	BBB	BBB

If AEP or any of its rated subsidiaries receive an upgrade from any of the rating agencies listed above, our borrowing costs could decrease. If we receive a downgrade in our credit ratings by one of the nationally recognized rating agencies listed above, our borrowing costs could increase and access to borrowed funds could be negatively affected.

Cash Flow

Our cash flows are a major factor in managing and maintaining our liquidity strength.

	Three Months Ended March 31, 2005	Three Months Ended March 31, 2004
	(in millions)	
Cash and cash equivalents at beginning of period	$ 320	$ 778
Cash flows from (used for):		
Operating activities	673	897
Investing activities	788	(186)
Financing activities	(520)	(576)
Net increase in cash and cash equivalents	941	135
Cash and cash equivalents at end of period	$ 1,261	$ 913
Other temporary cash investments	$ 181	$ 340

Cash from operations, combined with a bank-sponsored receivables purchase agreement and short-term borrowings, provide necessary working capital and help us meet other short-term cash needs. We use our corporate borrowing program to meet the short-term borrowing needs of our subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, we also fund, as direct borrowers, the short-term debt requirements of our other subsidiaries that are not participants in the Nonutility Money Pool. As of March 31, 2005, we had credit facilities totaling $2.5 billion to support our commercial paper program. At March 31, 2005, we had no outstanding short-term borrowings supported by the revolving credit facilities. JMG had commercial paper outstanding in the amount of $19 million. This commercial paper is specifically associated with the Gavin scrubber and is not supported by our credit facilities. The maximum amount of commercial paper outstanding during the quarter ended

March 31, 2005 was $25 million. The weighted-average interest rate for our commercial paper during the first quarter of 2005 was 2.59%.

We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding alternatives are arranged. Sources of long-term funding include issuance of common stock, preferred stock or long-term debt and sale-leaseback or leasing agreements.

In addition to our cash and cash equivalents we have other temporary cash investments on hand that factor in managing and maintaining our liquidity.

Operating Activities

	Three Months Ended March 31,	
	2005	2004
	(in millions)	
Net Income	$ 355	$ 282
Plus: Loss From Discontinued Operations	(1)	7
Income from Continuing Operations	354	289
Noncash Items Included in Earnings	243	222
Changes in Assets and Liabilities	76	386
Net Cash Flows From Operating Activities	$ 673	$ 897

The key drivers of the decrease in cash from operations for the first quarter of 2005 are the pension trust contribution of $102 million and the gain on sale of assets of $115 million, $112 million of which relates to the sale of our Texas REPs to Centrica.

2005 Operating Cash Flow

Our net cash flows from operating activities were $673 million for the first quarter of 2005. We produced income from continuing operations of $354 million during the period. Income from continuing operations for the period included noncash expense items of $318 million for depreciation, amortization, accretion and deferred taxes. In addition, there is a current period favorable impact for a net $27 million balance sheet change for risk management contracts that are marked-to-market. These contracts have an unrealized earnings impact as market prices move, and a cash impact upon settlement or upon disbursement or receipt of premiums. We made a $102 million contribution to our pension trust fund. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in these asset and liability accounts relates to a number of items; the most significant are a decrease in the balance of fuel, materials and supplies of $64 million primarily due to reduced gas inventory associated with the sale of HPL and an increase in the balance of accrued taxes of $245 million. Accrued taxes increased because our consolidated tax group was not required to make an estimated payment during the first quarter of 2005.

2004 Operating Cash Flow

Our net cash flows from operating activities were $897 million for the first quarter of 2004. We produced income from continuing operations of $289 million during the period. Income from continuing operations for the period included noncash items of $374 million for depreciation, amortization, accretion and deferred taxes. There was a current period unfavorable impact for a net $59 million balance sheet change for risk management contracts that were marked-to-market. These contracts have an unrealized earnings impact as market prices move, and a cash impact upon settlement or upon disbursement or receipt of premiums. The most significant changes in other activity in the asset and liability accounts are an increase in accrued taxes of $189 million and net changes in accounts receivable and accounts payable of $88 million.

Investing Activities

	Three Months Ended March 31, 2005	2004
	(in millions)	
Construction Expenditures	$ (465)	$ (305)
Change in Other Temporary Cash Investments, Net	94	64
Proceeds from Sales of Assets	1,157	40
Other	2	15
Net Cash Flows From (Used for) Investing Activities	$ 788	$ (186)

Our cash flows from investing activities were $788 million in 2005 primarily due to proceeds from the sale of HPL in 2005. We used the cash from asset sales to repurchase common stock. Our construction expenditures include environmental, transmission and distribution investments as we had planned. Our remaining construction expenditures for 2005 are estimated to be approximately $2.2 billion.

Our cash flows used for investing activities were $186 million in 2004 primarily due to construction expenditures.

Financing Activities

	Three Months Ended March 31, 2005	2004
	(in millions)	
Issuances of Common Stock	$ 17	$ 10
Repurchase of Common Stock	(434)	-
Issuances/Retirements of Debt, net	101	(444)
Retirement of Preferred Stock	(66)	(4)
Dividends Paid	(138)	(138)
Net Cash Flows Used for Financing Activities	$ (520)	$ (576)

Our cash flows used for financing activities in 2005 were $520 million. During the first quarter of 2005, we repurchased common stock using the proceeds from the sale of HPL. Our subsidiaries retired $66 million of cumulative preferred stock. See Note 10 for a complete discussion of debt issuances and retirements.

Our cash flows used for financing activities were $576 million in 2004. During the first quarter of 2004, we retired debt using cash from operating activities. We retired approximately $414 million of long-term debt, excluding $25 million related to an asset sale, and decreased our short-term debt by $103 million. We also issued approximately $73 million of long-term debt.

Off-balance Sheet Arrangements

We enter into off-balance sheet arrangements for various reasons including accelerating cash collections, reducing operational expenses and spreading risk of loss to third parties. Our current policy restricts the use of off-balance sheet financing entities or structures, except for traditional operating lease arrangements and sales of customer accounts receivable that we enter in the normal course of business. Our off-balance sheet arrangements have not changed significantly from year-end. For complete information on each of these off-balance sheet arrangements see the "Minority Interest and Off-balance Sheet Arrangements" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2004 Annual Report.

SIGNIFICANT MATTERS

Texas Regulatory Activity

Texas Restructuring

The stranded cost recovery process in Texas continues with the principal remaining component of the process being the PUCT's determination and approval of TCC's net stranded generation costs and other recoverable true-up items in TCC's future true-up filing. TCC has asked permission from the PUCT to file its True-up Proceeding after the sales of its interest in STP have been concluded. If the request is approved, it is anticipated that TCC's True-up Proceeding will be filed during the second quarter of 2005 seeking recovery of its net regulatory asset of $1.6 billion for its net stranded cost and other true-up items which it believes the Texas Restructuring Legislation allows.

TCC continues to accrue a carrying cost at the embedded 8.12% debt component rate and will continue to do so until it recovers its approved net true-up regulatory asset. In a nonaffiliated utility's securitization proceeding, the PUCT issued an order in March 2005 further clarifying how the amounts are to be calculated. This resulted in a reduction in TCC's accrued carrying costs based on the methodology detailed in the order for calculating a cost-of-money benefit related to Accumulated Deferred Federal Income Taxes (ADFIT) on TCC's net stranded cost and other true-up items retroactive to January 1, 2004. In the first quarter of 2005, TCC accrued carrying costs of $21 million, which was more than offset by an adverse adjustment of $27 million based on this order. The net reduction of $6 million in carrying costs is included in Other Income in the first quarter of 2005 on the accompanying Consolidated Statements of Income.

As of March 31, 2005, TCC has computed carrying costs of $450 million of which $296 million was recognized as income in 2004 and the first quarter of 2005. The remaining equity component of the carrying cost, of $154 million, will be recognized in income as collected.

When the True-up Proceeding is completed, TCC intends to file to recover the PUCT-approved net stranded generation costs and other true-up amounts, plus appropriate carrying costs, through a nonbypassable competition transition charge in the regulated transmission and distribution (T&D) rates and through an additional transition charge for amounts that can be recovered through the sale of securitization bonds.

We believe that our recorded net true-up regulatory asset of $1.6 billion at March 31, 2005 is recoverable under the Texas Restructuring Legislation; however, we anticipate that other parties will contend that material amounts of stranded costs should not be recovered. To the extent decisions of the PUCT in TCC's future True-up Proceeding differ from our interpretation and application of the Texas Restructuring Legislation and our evaluation of other true-up orders of nonaffiliated companies, additional material disallowances and reductions of recorded carrying costs are possible, which could have a material adverse effect on future results of operations, cash flows and possibly financial condition.

TCC Rate Case

TCC has an on-going T&D rate review before the PUCT. In that rate review, the PUCT has issued various decisions and conducted additional hearings in March 2005. At an open meeting on April 13, 2005, the PUCT decided all remaining issues except the amount of affiliate expenses to include in revenue requirements which the PUCT decided to defer. Adjusted for the decisions approved by the PUCT through April 13, 2005, the ALJ's recommended disallowances of affiliate expenses would produce an annual rate reduction of $25 million to $52 million. If TCC were to prevail on the affiliate expenses issue, the result would be an annual rate increase of $2 million. An order reducing TCC's rates could have an adverse effect on future results of operations and cash flows.

Ohio Regulatory Activity

Ohio Restructuring

In January 26, 2005 the PUCO approved Rate Stabilization Plans for CSPCo and OPCo (the Ohio companies). The plans provided, among other things, for CSPCo and OPCo to raise their generation rates by 3% and 7%, respectively, in 2006, 2007 and 2008 and provided for up to 4% of additional annual generation rate increases based on supporting the need for additional revenues. The plans also provided that the Ohio companies could recover in 2006, 2007 and 2008 environmental carrying costs and PJM RTO costs from 2004 and 2005 related to their obligation as the Provider of Last Resort in Ohio's customer choice program. First quarter of 2005 pretax earnings were increased by $13 million for CSPCo and $32 million for OPCo as a result of implementing this provision of the Rate Stabilization Plans. Of these amounts approximately $8 million for CSPCo and $21 for OPCo relate to 2004 environmental carrying costs and RTO costs.

IGCC Power Plant

On March 18, 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs related to building and operating a new 600 MW IGCC power plant using clean-coal technology. The application proposes cost recovery associated with the IGCC plant in three phases. In Phase 1, the Ohio companies would recover approximately $18 million in pre-construction costs during 2006. In Phase 2, the Ohio companies would recover approximately $237 million in construction financing costs from 2007 through mid-2010 when the plant is projected to be placed in commercial operation. The proposed recoveries in Phases 1 and 2 will be applied against the 4% limit on additional generation rate increases the Ohio companies could request in 2006, 2007 and 2008, under their Rate Stabilization Plans. In Phase 3, which begins when the plant enters commercial operation, projected to be in mid-2010, the Ohio companies would recover the projected $1.0 billion cost of the plant and a return on the unrecovered cost over its operating life along with fuel, replacement power and operation and maintenance costs.

Oklahoma Regulatory Activity

PSO Rate Review

PSO is involved in a commission staff-initiated rate review before the OCC seeking to increase its base rates, while various other parties made recommendations to reduce PSO's base rates. The annual rate reduction recommendations ranged between $15 million and $36 million. In March 2005, a settlement was negotiated and approved by the ALJ. Pending approval by the OCC, the settlement provides for a $7 million base rate reduction partially offset by a $6 million reduction in annual depreciation expense. The settlement also provides for recovery of $9 million of deferred fuel and the continuation of the vegetation management rider. In addition, the settlement eliminates a $9 million annual merger savings rate reduction rider at the end of December 2005. Finally, the settlement stipulates that PSO may not file for a base rate increase before April 1, 2006. The OCC did not approve the settlement in time for implementation of new base rates in May 2005 as agreed to by the parties, which voids the settlement. The OCC issued an Order approving the stipulation on May 2, 2005 with one exception. The Order approves the implementation of new base rates in June 2005 versus the stipulation date of May 2005.

PSO Fuel and Purchased Power

In 2002, PSO experienced a $44 million under-recovery of fuel costs resulting from a reallocation among AEP West companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO submitted a request to the OCC to collect those costs over 18 months. In August 2003, the OCC Staff filed testimony recommending PSO recover $42 million of the reallocation over three years. In September 2003, the OCC expanded the case to include a full review of PSO's 2001 fuel and purchased power practices.

In the proceeding, parties alleged that the allocation of off-system sales margins between AEP East and AEP West companies were inconsistent with the FERC-approved Operating Agreement and System Integration Agreement and AEP West companies should have received more margins. The OCC expanded the scope of the proceeding to include the off-system sales margin issue for the year 2002 and an intervenor filed a motion to expand the scope to review this same issue for the years 2003 and 2004. Using the intervenors' method, PSO estimates that the increase in margins would be $29 million through March 31, 2005. In April 2005, the OCC heard arguments from intervenors that requested the OCC to conduct a prudence review of PSO's fuel and purchased power for 2003. Management is unable to predict if the OCC will order a prudence review of PSO's fuel and purchased power activities for 2003 or the ultimate effect of these proceedings on our revenues, results of operations, cash flows and financial condition.

FERC Order on Regional Through and Out Rates

A load-based transitional transmission rate mechanism called SECA became effective December 1, 2004 to mitigate the loss of revenues due to the FERC's elimination of through and out (T&O) transmission rates. Billing statements from PJM for the first quarter of 2005 did not reflect any credits to AEP for SECA revenues. Based upon the SECA transition rate methodology approved by the FERC, AEP accrued $26 million of SECA revenue in the first quarter of 2005 and has a receivable for SECA revenues of $37 million at March 31, 2005. SECA billings by PJM crediting AEP for their SECA revenue are scheduled to begin in May 2005 with retroactive adjustments to be billed by PJM in June and July 2005.

The AEP East companies received approximately $196 million of T&O rate revenues for the twelve months ended September 30, 2004, the twelve months prior to AEP joining PJM. The portion of those revenues associated with transactions for which the T&O rate is being eliminated and replaced by SECA transition rates was $171 million. At this time, management is unable to predict whether the SECA transition rates will fully compensate the AEP East companies for their lost T&O revenues for the period December 1, 2004 through March 31, 2006 and whether, effective with the expiration of the SECA transition rates on March 31, 2006, the resultant increase in the AEP East zonal transmission rates applicable to AEP's internal load will be sufficient to replace the SECA transition rate revenues and whether the new rates will be recoverable on a timely basis in the AEP East state retail jurisdictions and from wholesale customers within the AEP zone. If the SECA transition rates do not fully compensate AEP for its lost T&O revenues through March 31, 2006, if AEP zonal rates are not sufficiently increased by the FERC after March 31, 2006, or if any increase in the AEP East companies' transmission expenses from higher AEP zonal rates are not fully recovered in retail and wholesale rates on a timely basis, future results of operations, cash flows and financial condition could be materially affected.

Litigation

We continue to be involved in various litigation described in the "Significant Factors – Litigation" section of Management's Financial Discussion and Analysis of Results of Operations in our 2004 Annual Report. The 2004 Annual Report should be read in conjunction with this report in order to understand other litigation that did not have significant changes in status since the issuance of our 2004 Annual Report, but may have a material impact on our future results of operations, cash flows and financial condition. Other matters described in the 2004 Annual Report that did not have significant changes during the first quarter of 2005, that should be read in order to gain a full understanding of our current litigation include: (1) Bank of Montreal Claim, (2) Coal Transportation Dispute, (3) Shareholders' Litigation and (4) Potential Uninsured Losses.

Federal EPA Complaint and Notice of Violation

See discussion of New Source Review Litigation within "Significant Factors – Environmental Matters."

Enron Bankruptcy

In 2002, certain of our subsidiaries filed claims against Enron and its subsidiaries in the Enron bankruptcy proceeding pending in the U.S. Bankruptcy Court for the Southern District of New York. At the date of Enron's bankruptcy, certain of our subsidiaries had open trading contracts and trading accounts receivables and payables with Enron. In addition, on June 1, 2001, we purchased HPL from Enron. Various HPL-related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy.

Enron Bankruptcy – Right to use of cushion gas agreements – In connection with the 2001 acquisition of HPL, we entered into an agreement with BAM Lease Company, which grants HPL the exclusive right to use approximately 65 billion cubic feet (BCF) of cushion gas required for the normal operation of the Bammel gas storage facility. At the time of our acquisition of HPL, Bank of America (BOA) and certain other banks (the BOA Syndicate) and Enron entered into an agreement granting HPL the exclusive use of 65 BCF of cushion gas. Also at the time of our acquisition, Enron and the BOA Syndicate also released HPL from all prior and future liabilities and obligations in connection with the financing arrangement.

After the Enron bankruptcy, HPL was informed by the BOA Syndicate of a purported default by Enron under the terms of the financing arrangement. In July 2002, the BOA Syndicate filed a lawsuit against HPL in the state court of Texas seeking a declaratory judgment that the BOA Syndicate has a valid and enforceable security interest in gas purportedly in the Bammel storage reservoir. In December 2003, the Texas state court granted partial summary judgment in favor of the BOA Syndicate. HPL appealed this decision. In June 2004, BOA filed an amended petition in a separate lawsuit in Texas state court seeking to obtain possession of up to 55 BCF of storage gas in the Bammel storage facility or its fair value. Following an adverse decision on its motion to obtain possession of this gas, BOA voluntarily dismissed this action. In October 2004, BOA refiled this action. HPL filed a motion to have the case assigned to the judge who heard the case originally and that motion was granted. HPL intends to defend vigorously against BOA's claims.

In October 2003, AEP filed a lawsuit against BOA in the United States District Court for the Southern District of Texas. BOA led a lending syndicate involving the 1997 gas monetization that Enron and its subsidiaries undertook and the leasing of the Bammel underground gas storage reservoir to HPL. The lawsuit asserts that BOA made misrepresentations and engaged in fraud to induce and promote the stock sale of HPL, that BOA directly benefited from the sale of HPL and that AEP undertook the stock purchase and entered into the Bammel storage facility lease arrangement with Enron and the cushion gas arrangement with Enron and BOA based on misrepresentations that BOA made about Enron's financial condition that BOA knew or should have known were false including that the 1997 gas monetization did not contravene or constitute a default of any federal, state, or local statute, rule, regulation, code or any law. In February 2004, BOA filed a motion to dismiss this Texas federal lawsuit. In September 2004, the Magistrate Judge issued a Recommended Decision and Order recommending that BOA's Motion to Dismiss be denied, that the five counts in the lawsuit seeking declaratory judgments involving the Bammel reservoir and the right to use and cushion gas consent agreements be transferred to the Southern District of New York and that the four counts alleging breach of contract, fraud and negligent misrepresentation proceed in the Southern District of Texas. BOA objected to the Magistrate Judge's decision. On April 6, 2005, the Judge entered an order overruling BOA's objections, denying BOA's Motion to Dismiss and severing and transferring the declaratory judgment claims to the Southern District of New York.

In February 2004, in connection with BOA's dispute, Enron filed Notices of Rejection regarding the cushion gas exclusive right to use agreement and other incidental agreements. We have objected to Enron's attempted rejection of these agreements and have filed an adversary proceeding contesting Enron's right to reject these agreements.

In January 2005, we sold a 98% limited partner interest in HPL. We have indemnified the buyer of the 98% interest in HPL against any damages resulting from the BOA litigation up to the purchase price. The recognition and the amount of the gain is dependent upon the ultimate resolution of the BOA dispute and the costs, if any, associated with the resolution of this matter.

Enron Bankruptcy – Commodity trading settlement disputes – In September 2003, Enron filed a complaint in the Bankruptcy Court against AEPES challenging AEP's offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately $125 million plus interest in connection with gas related trading transactions. We asserted our right to offset trading payables owed to various Enron entities against trading receivables due to several of our subsidiaries. The parties are currently in nonbinding court-sponsored mediation.

In December 2003, Enron filed a complaint in the Bankruptcy Court against AEPSC seeking approximately $93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron, AEP and Allegheny Energy Supply, LLC during November 2001. Enron's claim seeks to unwind the effects of the transaction. AEP believes it has several defenses to the claims in the action being brought by Enron. The parties are currently in nonbinding court-sponsored mediation.

Enron Bankruptcy – Summary – The amount expensed in prior years in connection with the Enron bankruptcy was based on an analysis of contracts where AEP and Enron entities are counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities and management's analysis of the HPL-related purchase contingencies and indemnifications. As noted above, Enron has challenged our offsetting of receivables and payables and there is a dispute regarding the cushion gas agreement. Although management is unable to predict the outcome of these lawsuits, it is possible that their resolution could have an adverse impact on our results of operations, cash flows or financial condition.

Merger Litigation

In 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC did not adequately explain that the June 15, 2000 merger of AEP with CSW meets the requirements of the PUHCA and sent the case back to the SEC for further review. Specifically, the court told the SEC to revisit the basis for its conclusion that the merger met PUHCA requirements that utilities be "physically interconnected" and confined to a "single area or region." In January 2005, a hearing was held before an ALJ.

On May 3, 2005, the ALJ issued an Initial Decision concluding that the AEP System is "physically interconnected" but is not confined to a "single area or region." Therefore, the ALJ concluded that the combined AEP/CSW system does not constitute a single integrated public utility system under PUHCA. Management believes that the merger meets the requirements of PUHCA and will file a petition for review of this Initial Decision. The SEC will review the Initial Decision.

Natural Gas Markets Lawsuits

In November 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County, California Superior Court against forty energy companies, including AEP, and two publishing companies alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP has been dismissed from the case. The plaintiff had stated an intention to amend the complaint to add an AEP subsidiary as a defendant. The plaintiff amended the complaint but did not name any AEP company as a defendant. Since then, a number of cases have been filed in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. In some of these cases, AEP (or a subsidiary) is among the companies named as defendants. These cases are at various pre-trial stages. Several of these cases had been transferred to the United States District Court for the District of Nevada but were subsequently remanded to California state court. In April 2005, the judge in Nevada dismissed one of the remaining cases in which AEP was a defendant on the basis of the filed rate doctrine. We will continue to defend vigorously each case where an AEP company is a defendant.

Texas Commercial Energy, LLP Lawsuit

Texas Commercial Energy, LLP (TCE), a Texas REP, filed a lawsuit in federal District Court in Corpus Christi, Texas, in July 2003, against us and four of our subsidiaries, certain nonaffiliated energy companies and ERCOT. The action alleges violations of the Sherman Antitrust Act, fraud, negligent misrepresentation, breach of fiduciary duty, breach of contract, civil conspiracy and negligence. The allegations, not all of which are made against the AEP companies, range from anticompetitive bidding to withholding power. TCE alleges that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced it into bankruptcy when it was unable to raise prices to its customers due to fixed price contracts. The suit alleges over $500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. Two additional parties, Utility Choice, LLC and Cirro Energy Corporation, sought leave to intervene as plaintiffs asserting similar claims. We filed a Motion to Dismiss in September 2003. In February 2004, TCE filed an amended complaint. We filed a Motion to Dismiss the amended complaint. In June 2004, the Court dismissed all claims against the AEP companies. TCE has appealed the trial court's decision to the United States Court of Appeals for the Fifth Circuit.

In March 2005, Utility Choice, LLC and Cirro Energy Corporation filed in U.S. District Court alleging similar violations as those alleged in the TCE lawsuit. In April 2005, the defendants filed a Motion to Stay this case, pending the outcome of the appeal in the TCE case.

Cornerstone Lawsuit

In the third quarter of 2003, Cornerstone Propane Partners filed an action in the United States District Court for the Southern District of New York against forty companies, including AEP and AEPES seeking class certification and alleging unspecified damages from claimed price manipulation of natural gas futures and options on the NYMEX from January 2000 through December 2002. Thereafter, two similar actions were filed in the same court against a number of companies including AEP and AEPES making essentially the same claims as Cornerstone Propane Partners and also seeking class certification. On December 5, 2003, the Court issued its initial Pretrial Order consolidating all related cases, appointing co-lead counsel and providing for the filing of an amended consolidated complaint. In January 2004, plaintiffs filed an amended consolidated complaint. We and the other defendants filed a motion to dismiss the complaint, which the Court denied in September 2004. Plaintiffs have filed a Motion for Class Certification. The defendants, including AEP and AEPES, filed their opposition to class certification on April 8, 2005. Briefing on the issue of class certification is expected to be completed in the second quarter of 2005. Discovery is continuing in the case with a discovery cut-off date of June 30, 2005. We intend to defend vigorously against these claims.

SWEPCo Notice of Enforcement and Notice of Citizen Suit

On July 13, 2004, two special interest groups issued a notice of intent to commence a citizen suit under the CAA for alleged violations of various permit conditions in permits issued to SWEPCo's Welsh, Knox Lee, and Pirkey plants. The allegations at the Welsh Plant concern compliance with emission limitations on particulate matter and carbon monoxide, compliance with a referenced design heat input value, and compliance with certain reporting requirements. The allegations at the Knox Lee Plant relate to the receipt of an off-specification fuel oil, and the allegations at Pirkey Plant relate to testing and reporting of volatile organic compound emissions. On March 10, 2005, a complaint was filed in Federal District Court for the Eastern District of Texas by the two special interest groups, alleging violations of the CAA at Welsh Plant. SWEPCo will file a response to the complaint in May 2005.

On July 19, 2004, the Texas Commission on Environmental Quality (TCEQ) issued a Notice of Enforcement to SWEPCo relating to the Welsh Plant containing a summary of findings resulting from a compliance investigation at the plant. The summary includes allegations concerning compliance with certain recordkeeping and reporting requirements, compliance with a referenced design heat input value in the Welsh permit, compliance with a fuel sulfur content limit, and compliance with emission limits for sulfur dioxide. On April 11, 2005, TCEQ issued an Executive Director's Preliminary Report and Petition recommending the entry of an enforcement order to undertake certain corrective actions and assessing an administrative penalty of $228,312 against SWEPCo based on alleged violations of certain representations regarding heat input and fuel characteristics in SWEPCo's permit application and the violations of certain recordkeeping and reporting requirements. SWEPCo responded to the preliminary report and petition on May 2, 2005. The enforcement order contains a recommendation that would limit the heat input on each Welsh unit to the referenced heat input contained within the permit application within 10 days of the issuance of a final TCEQ order and until a permit amendment is issued. SWEPCo had previously requested a permit alteration to remove the references to a specific heat input value for each Welsh unit.

On August 13, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the off-specification fuel oil deliveries at the Knox Lee Plant. On April 11, 2005, TCEQ issued an Executive Director's Preliminary Report and Petition recommending the entry of an enforcement order and assessing an administrative penalty of $5,550 against SWEPCo based on alleged violations of certain permit requirements at Knox Lee. SWEPCo responded to the preliminary report and petition on May 2, 2005.

Management is unable to predict the timing of any future action by TCEQ or the special interest groups or the effect of such actions on results of operations, cash flows or financial condition.

TEM Litigation

We have agreements with Juniper Capital L.P. (Juniper) under which Juniper constructed and financed a nonregulated merchant power generation facility (Facility) near Plaquemine, Louisiana and leased the Facility to us. We have subleased the Facility to the Dow Chemical Company (Dow). The Facility is a Dow-operated "qualifying cogeneration facility" for purposes of PURPA.

Dow uses a portion of the energy produced by the Facility and sells the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow for a 20-year term. Because the Facility is a major steam supply for Dow, Dow is expected to operate the Facility at certain minimum levels, and OPCo is obligated to purchase the energy generated at those minimum operating levels (expected to be approximately 270 MW). OPCo sells the purchased energy at market prices in the Entergy sub-region of the Southeastern Electric Reliability Council market.

OPCo has also agreed to sell up to approximately 800 MW of energy to SUEZ Energy Marketing NA, Inc. (formerly known as Tractebel Energy Marketing, Inc.) (TEM) for a period of 20 years under a Power Purchase and Sale Agreement dated November 15, 2000 (PPA), at a price that is currently in excess of market. Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as nonconforming. Commercial operation for purposes of the PPA began April 2, 2004.

In September 2003, TEM and AEP separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. We allege that TEM has breached the PPA, and we are seeking a determination of our rights under the PPA. TEM alleges that the PPA never became enforceable, or alternatively, that the PPA has already been terminated as the result of AEP's breaches. If the PPA is deemed terminated or found to be unenforceable by the court, we could be adversely affected to the extent we are unable to find other purchasers of the power with similar contractual terms and to the extent we do not fully recover claimed termination value damages from TEM. The corporate parent of TEM (SUEZ-TRACTEBEL S.A.) has provided a limited guaranty.

In November 2003, the above litigation was suspended pending final resolution in arbitration of all issues pertaining to the protocols relating to the dispatching, operation, and maintenance of the Facility and the sale and delivery of electric power products. In the arbitration proceedings, TEM argued that in the absence of mutually agreed upon protocols there were no commercially reasonable means to obtain or deliver the electric power products and therefore the PPA is not enforceable. TEM further argued that the creation of the protocols is not subject to arbitration. The arbitrator ruled in favor of TEM on February 11, 2004 and concluded that the "creation of protocols" was not subject to arbitration, but did not rule upon the merits of TEM's claim that the PPA is not enforceable. On January 21, 2005, the District Court granted AEP partial summary judgment on this issue, holding that the absence of operating protocols does not prevent enforcement of the PPA.

On March 26, 2004, OPCo requested that TEM provide assurances of performance of its future obligations under the PPA, but TEM refused to do so. As indicated above, OPCo also gave notice to TEM and declared April 2, 2004 as the "Commercial Operations Date." Despite OPCo's prior tenders of replacement electric power products to TEM beginning May 1, 2003 and despite OPCo's tender of electric power products from the Facility to TEM beginning April 2, 2004, TEM refused to accept and pay for these electric power products under the terms of the PPA. On April 5, 2004, OPCo gave notice to TEM that OPCo (i) was suspending performance of its obligations under the PPA, (ii) would be seeking a declaration from the New York federal court that the PPA has been terminated and (iii) would be pursuing against TEM, and Tractebel SA under the guaranty, damages and the full termination payment value of the PPA.

A bench trial was conducted in March and April 2005.

Environmental Matters

As discussed in our 2004 Annual Report, there are emerging environmental control requirements that we expect will result in substantial capital investments and operational costs. The sources of these future requirements include:

- Legislative and regulatory proposals to adopt stringent controls on sulfur dioxide (SO_2), nitrogen oxide (NO_x) and mercury emissions from coal-fired power plants,
- Clean Water Act rules to reduce the impacts of water intake structures on aquatic species at certain of our power plants, and
- Possible future requirements to reduce carbon dioxide emissions to address concerns about global climatic change.

This discussion updates certain events occurring in 2005. You should also read the "Significant Factors – Environmental Matters" section within Management's Financial Discussion and Analysis of Results of Operations in our 2004 Annual Report for a description of all environmental matters affecting us, including, but not limited to, (1) the current air quality regulatory framework, (2) estimated air quality environmental investments, (3) the Comprehensive Environmental Response Compensation and Liability Act (Superfund) and state remediation, (4) global climate change, (5) carbon dioxide public nuisance claims, (6) costs for spent nuclear fuel disposal and decommissioning, and (7) Clean Water Act regulation.

Future Reduction Requirements for SO_2, NO_x and Mercury

Regulatory Emissions Reductions

In January 2004, the Federal EPA published two proposed rules that would collectively require reductions of approximately 70% each in emissions of SO_2, NO_x and mercury from coal-fired electric generating units by 2015 (2018 for mercury). This initiative has two major components:

- The Federal EPA proposed a Clean Air Interstate Rule (CAIR) to reduce SO_2 and NO_x emissions across the Eastern United States (29 states and the District of Columbia) and make progress toward attainment of the new fine particulate matter and ground-level ozone national ambient air quality standards. These reductions could also satisfy these states' obligations to make reasonable progress towards the national visibility goal under the regional haze program.
- The Federal EPA proposed to regulate mercury emissions from coal-fired electric generating units.

On March 14, 2005, the Administrator of the Federal EPA signed the final CAIR. The rule is slightly revised from the proposed version released in January 2004, and includes both a seasonal and annual NO_x control program as well as an annual SO_2 control program. All of the states in which our generating facilities are located will be subject to the regional and annual NO_x control programs and the annual SO_2 control program, except for Texas, Oklahoma and Arkansas. Texas will be subject to the annual programs only. Arkansas will be subject to the seasonal NO_x control program only. Oklahoma is not affected by CAIR. In addition, the compliance deadline for Phase I for the NO_x control program has been accelerated to 2009, and will replace any obligations imposed by the NO_x State Implementation Plan (SIP) Call in 2009.

On March 15, 2005, the Administrator of the Federal EPA signed a final Clean Air Mercury Rule (CAMR) that will permit mercury emission reductions to be achieved from existing sources through a national cap-and-trade approach. The cap-and-trade approach would include a two-phase mercury reduction program for coal-fired utilities. The final CAMR imposes a national cap on mercury emissions from coal-fired power plants of 38 tons by 2010 and 15 tons by 2018.

The changes in the Federal EPA's final CAIR and CAMR have not caused us to revise our estimates of the capital investments necessary to achieve compliance with these requirements. However, final rules give states substantial discretion in developing their rules to implement these cap-and-trade programs, and states will have 18 months after publication of the notice of final rulemaking to submit their revised SIPs. As a result, the ultimate requirements may not be known for several years and may depart significantly from the original proposed rules described here. If states elect not to participate in the federal cap-and-trade programs, or elect to impose additional requirements on individual units that are already subject to CAIR and/or the CAMR, our costs could increase significantly. The cost of compliance could have an adverse effect on future results of operations, cash flows and financial condition unless recovered from customers.

New Source Review Litigation

Under the CAA, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant.

The Federal EPA and a number of states have alleged APCo, CSPCo, I&M, OPCo and other nonaffiliated utilities modified certain units at coal-fired generating plants in violation of the new source review requirements of the CAA. The Federal EPA filed its complaints against our subsidiaries in U.S. District Court for the Southern District of Ohio. The Court also consolidated a separate lawsuit, initiated by certain special interest groups, with the Federal EPA case. The alleged modifications occurred at our generating units over a 20-year period.

On June 18, 2004, the Federal EPA issued a Notice of Violation (NOV) in order to "perfect" its complaint in the pending litigation. The NOV expands the number of alleged "modifications" undertaken at the Amos, Cardinal, Conesville, Kammer, Muskingum River, Sporn and Tanners Creek plants during scheduled outages on these units from 1979 through the present. Approximately one-third of the allegations in the NOV are already contained in allegations made by the states or the special interest groups in the pending litigation. The Federal EPA filed a motion to amend its complaints and to expand the scope of the pending litigation. The AEP subsidiaries opposed that motion. In September 2004, the judge disallowed the addition of claims to the pending case. The judge also granted motions to dismiss a number of allegations in the original filing. The Federal EPA and the states each have filed an additional complaint alleging violations of the new source review requirements at units at the Amos and Conesville plants that were not allowed to be added to the pending case. These separate complaints have been assigned to the same judge in the Southern District Court.

In September 2004, the Sierra Club filed a complaint under the citizen suit provisions of the CAA in the U.S. District Court for the Southern District of Ohio alleging that violations of the prevention of significant deterioration and New Source Performance Standards requirements of the CAA and the opacity provisions of the Ohio SIP occurred at the J.M. Stuart Station, and seeking injunctive relief and civil penalties. Stuart Station is jointly owned by CSPCo (26%) and two nonaffiliated utilities. The owners have filed a motion to dismiss portions of the complaint, based primarily upon the federal statute of limitations. In March 2005, in an unrelated case alleging new source review permitting claims against the Tennessee Valley Authority (TVA), the court granted a motion to dismiss the claims against TVA on similar grounds. The owners have advised the court of this new decision. We believe the allegations in the complaint are without merit, and intend to defend vigorously this action. Management is unable to predict the timing of any future action by the special interest group or the effect of such actions on future operations or cash flows.

We are unable to estimate the loss or range of loss related to any contingent liability we might have for civil penalties under the CAA proceedings. We are also unable to predict the timing of resolution of these matters due to the number of alleged violations and the significant number of issues yet to be determined by the Court. If we do not prevail, any capital and operating costs of additional pollution control equipment that may be required, as well as any penalties imposed, would adversely affect future results of operations, cash flows and possibly financial condition unless such costs can be recovered through regulated rates and market prices for electricity.

Emergency Release Reporting

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) requires immediate reporting to the Federal EPA for releases of hazardous substances to the environment above the identified reportable quantity (RQ). The Environmental Planning and Community Right-to-Know Act (EPCRA) requires immediate reporting of releases of hazardous substances that cross property boundaries of the releasing facility.

On July 27, 2004, the Federal EPA Region 5 issued an Administrative Complaint related to alleged failure of I&M to immediately report under Superfund and EPCRA a November 2002 release of sodium hypochlorite from the Cook Plant. The Federal EPA's Complaint seeks an immaterial amount of civil penalties. I&M has requested a hearing and raised several defenses to the claim, including federally permitted release exemption from reporting. Negotiations on the penalty amount are continuing.

On December 21, 2004, the Federal EPA notified OPCo of its intent to file a Civil Administrative Complaint, alleging one violation of Superfund reporting obligations and two violations of EPCRA for failure to timely report a June 2004 release of an RQ amount of ammonia from OPCo's Gavin Plant SCR system. The Federal EPA indicated its intent to seek civil penalties. In February 2005, OPCo provided relevant information that the Federal EPA should consider in advance of any filing.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2004 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

As a major power producer and marketer of wholesale electricity, coal and emission allowances, we have certain market risks inherent in our business activities. These risks include commodity price risk, interest rate risk, foreign exchange risk and credit risk. They represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

In the Investment-Gas Operations segment, AEP continues to hold forward gas contracts that were not sold with the gas pipeline and storage assets. These contracts are primarily financial derivatives with some physical contracts which will gradually wind down and completely expire in 2011. The AEP risk objective is to keep these positions risk neutral through maturity.

We have established policies and procedures that allow us to identify, assess, and manage market risk exposures in our day-to-day operations. Our risk policies have been reviewed with our Board of Directors and approved by our Risk Executive Committee. Our Chief Risk Officer administers our risk policies and procedures. The Risk Executive Committee establishes risk limits, approves risk policies, and assigns responsibilities regarding the oversight and management of risk and monitors risk levels. Members of this committee receive daily, weekly, and monthly reports regarding compliance with policies, limits and procedures. Our committee meets monthly and consists of the Chief Risk Officer, Credit Risk Management, Market Risk Oversight, and senior financial and operating managers.

We actively participate in the Committee of Chief Risk Officers (CCRO) to develop standard disclosures for risk management activities around risk management contracts. The CCRO is composed of the chief risk officers of major electricity and gas companies in the United States. The CCRO adopted disclosure standards for risk management contracts to improve clarity, understanding and consistency of information reported. Implementation of the disclosures is voluntary. We support the work of the CCRO and have embraced the disclosure standards. The following tables provide information on our risk management activities:

Mark-to-Market Risk Management Contract Net Assets (Liabilities)

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

MTM Risk Management Contract Net Assets
Three Months Ended March 31, 2005
(in millions)

	Utility Operations	Investments-Gas Operations	Investments-UK Operations	Total
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2004	$ 277	$ -	$ (12)	$ 265
(Gain) Loss from Contracts Realized/Settled During the Period (a)	(37)	(5)	12	(30)
Fair Value of New Contracts When Entered During the Period (b)	1	-	-	1
Net Option Premiums Paid/(Received) (c)	-	-	-	-
Change in Fair Value Due to Valuation Methodology Changes	-	-	-	-
Changes in Fair Value of Risk Management Contracts (d)	29	(5)	-	24
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)	(8)	-	-	(8)
Total MTM Risk Management Contract Net Assets (Liabilities) at March 31, 2005	$ 262	$ (10)	$ -	252
Net Cash Flow and Fair Value Hedge Contracts (f)				(61)
Ending Net Risk Management Assets at March 31, 2005				$ 191

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized gains from risk management contracts and related derivatives that settled during 2005 where we entered into the contract prior to 2005.

(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 2005. 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 entered in 2005.

(d) "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.

(e) "Changes 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 Consolidated Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities for those subsidiaries that operate in regulated jurisdictions.

(f) "Net Cash Flow and Fair Value Hedge Contracts" (pretax) are discussed in detail within the following pages.

Detail on MTM Risk Management Contract Net Assets (Liabilities)
As of March 31, 2005
(in millions)

	Utility Operations	Investments-Gas Operations	Total
Current Assets	$ 545	$ 291	$ 836
Noncurrent Assets	497	146	643
Total Assets	1,042	437	1,479
Current Liabilities	(480)	(286)	(766)
Noncurrent Liabilities	(300)	(161)	(461)
Total Liabilities	(780)	(447)	(1,227)
Total Net Assets (Liabilities), excluding Hedges	$ 262	$ (10)	$ 252

Reconciliation of MTM Risk Management Contracts to Consolidated Balance Sheets
As of March 31, 2005
(in millions)

	MTM Risk Management Contracts (a)	PLUS: Hedges	Total (b)
Current Assets	$ 836	$ 29	$ 865
Noncurrent Assets	643	3	646
Total MTM Derivative Contract Assets	1,479	32	1,511
Current Liabilities	(766)	(84)	(850)
Noncurrent Liabilities	(461)	(9)	(470)
Total MTM Derivative Contract Liabilities	(1,227)	(93)	(1,320)
Total MTM Derivative Contract Net Assets	$ 252	$ (61)	$ 191

(a) Does not include Cash Flow and Fair Value Hedges.
(b) 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 Consolidated Balance Sheets.

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

The table presenting maturity and source of fair value of MTM risk management contract net assets (liabilities) 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 (Liabilities)
Fair Value of Contracts as of March 31, 2005
(in millions)

	Remainder 2005	2006	2007	2008	2009	After 2009	Total (c)
Utility Operations:							
Prices Actively Quoted – Exchange Traded Contracts	$ (67)	$ 18	$ 22	$ -	$ -	$ -	$ (27)
Prices Provided by Other External Sources – OTC Broker Quotes (a)	131	63	46	21	-	-	261
Prices Based on Models and Other Valuation Methods (b)	(2)	(36)	(13)	20	31	28	28
Total	$ 62	$ 45	$ 55	$ 41	$ 31	$ 28	$ 262
Investments - Gas Operations:							
Prices Actively Quoted – Exchange Traded Contracts	$ 34	$ (7)	$ 4	$ -	$ -	$ -	$ 31
Prices Provided by Other External Sources – OTC Broker Quotes (a)	(21)	(3)	-	-	-	-	(24)
Prices Based on Models and Other Valuation Methods (b)	(3)	(3)	(3)	(2)	(4)	(2)	(17)
Total	$ 10	$ (13)	$ 1	$ (2)	$ (4)	$ (2)	$ (10)
Total:							
Prices Actively Quoted – Exchange Traded Contracts	$ (33)	$ 11	$ 26	$ -	$ -	$ -	$ 4
Prices Provided by Other External Sources – OTC Broker Quotes (a)	110	60	46	21	-	-	237
Prices Based on Models and Other Valuation Methods (b)	(5)	(39)	(16)	18	27	26	11
Total	$ 72	$ 32	$ 56	$ 39	$ 27	$ 26	$ 252

(a) Prices provided by other external sources – Reflects information obtained from over-the-counter brokers (OTC), industry services, or multiple-party on-line platforms.
(b) Modeled – In the 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 is limited, such valuations are classified as modeled.
(c) Amounts exclude Cash Flow and Fair Value Hedges.

The determination of the point at which a market is no longer liquid for placing it in the Modeled category in the preceding table varies by market. The following table reports an estimate of the maximum tenors (contract maturities) of the liquid portion of each energy market.

Maximum Tenor of the Liquid Portion of Risk Management Contracts
As of March 31, 2005

Commodity	Transaction Class	Market/Region	Tenor (in months)
Natural Gas	Futures	NYMEX/Henry Hub	60
	Physical Forwards	Gulf Coast, Texas	24
	Swaps	Gas East – Northeast, Mid-continent, Gulf Coast, Texas	24
	Swaps	Gas West – Rocky Mountains, West Coast	24
	Exchange Option Volatility	NYMEX/Henry Hub	12
Power	Futures	Power East – PJM	36
	Physical Forwards	Power East – Cinergy	21
	Physical Forwards	Power East – PJM West	33
	Physical Forwards	Power East – AEP Dayton (PJM)	21
	Physical Forwards	Power East – NEPOOL	21
	Physical Forwards	Power East – NYPP	33
	Physical Forwards	Power East – ERCOT	48
	Physical Forwards	Power East – Com Ed	21
	Physical Forwards	Power West – Palo Verde, North Path 15, South Path 15, MidColumbia, Mead	45
	Peak Power Volatility (Options)	Cinergy	12
	Peak Power Volatility (Options)	PJM	12
Crude Oil	Swaps	West Texas Intermediate	36
Emissions	Credits	SO_2, NO_x	45
Coal	Physical Forwards	PRB, NYMEX, CSX	21

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 and gas operations. We monitor these risks on our future operations and may employ various commodity instruments and cash flow hedges to mitigate the impact of these fluctuations on the future cash flows from assets. We do not hedge all commodity price risk.

We employ the use of interest rate forward and swap transactions in order to manage interest rate risk to existing floating rate debt and to manage interest rate exposure on anticipated borrowings of fixed-rate debt. We do not hedge all interest rate exposure.

The tables below provide detail on effective cash flow hedges under SFAS 133 included in our Balance Sheets. The data in the first table indicates the magnitude of SFAS 133 hedges that 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. This table further indicates what portions of these hedges are expected to be reclassified into net income in the next 12 months. The second table provides the nature of changes from December 31, 2004 to March 31, 2005.

Information on energy commodity risk management activities is presented separately from interest rate risk management activities. In accordance with GAAP, all amounts are presented net of related income taxes.

Cash Flow Hedges included in Accumulated Other Comprehensive Income (Loss) On the Balance Sheet as of March 31, 2005 (in millions)

	Accumulated Other Comprehensive Income (Loss) After Tax (a)	Portion Expected to be Reclassified to Earnings During the Next 12 Months (b)
Power and Gas	$ (36)	$ (34)
Interest Rate	(15)	(3)
Total	$ (51)	$ (37)

Total Accumulated Other Comprehensive Income (Loss) Activity Three Months Ended March 31, 2005 (in millions)

	Power and Gas	Interest Rate	Total
Beginning Balance, December 31, 2004	$ 23	$ (23)	$ -
Changes in Fair Value (c)	(34)	8	(26)
Reclassifications from AOCI to Net Income (d)	(25)	-	(25)
Ending Balance, March 31, 2005	$ (36)	$ (15)	$ (51)

(a) "Accumulated Other Comprehensive Income (Loss) After Tax" – Gains/losses are net of related income taxes that have not yet been included in the determination of net income; reported as a separate component of shareholders' equity on the balance sheet.
(b) "Portion Expected to be Reclassified to Earnings During the Next 12 Months" – Amount of gains or losses (realized or unrealized) from derivatives used as hedging instruments that have been deferred and are expected to be reclassified into net income during the next 12 months at the time the hedged transaction affects net income.
(c) "Changes in Fair Value" – Changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at March 31, 2005. Amounts are reported net of related income taxes.
(d) "Reclassifications from AOCI to Net Income" – 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.

Credit Risk

We limit credit risk by assessing creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness after transactions have been initiated. Only after an entity has met our internal credit rating criteria will we extend unsecured credit. We use Moody's, S&P and qualitative and quantitative data to assess the financial health of counterparties on an ongoing basis. Our analysis, in conjunction with the rating agencies' information, is used to determine appropriate risk parameters. We also require cash deposits, letters of credit and parental/affiliate guarantees as security from counterparties depending upon credit quality in our normal course of business.

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. At March 31, 2005, our credit exposure net of credit collateral to sub investment grade counterparties was approximately 17.6%, expressed in terms of net MTM assets and net receivables. As of March 31, 2005, the following table approximates our counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable (in millions, except number of counterparties):

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%
Investment Grade	$ 781	$ 191	$ 590	1	$ 97
Split Rating	18	7	11	2	11
Noninvestment Grade	269	143	126	3	93
No External Ratings:					
Internal Investment Grade	44	-	44	2	32
Internal Noninvestment Grade	14	3	11	2	11
Total	$ 1,126	$ 344	$ 782	10	$ 244

Generation Plant Hedging Information

This table provides information on operating measures regarding the proportion of output of our generation facilities (based on economic availability projections) economically hedged, including both contracts designated as cash flow hedges under SFAS 133 and contracts not designated as cash flow hedges. This information is forward-looking and provided on a prospective basis through December 31, 2007. Please note that this table is a point-in-time estimate, subject to changes in market conditions and our decisions on how to manage operations and risk. "Estimated Plant Output Hedged" represents the portion of MWHs of future generation/production for which we have sales commitments or estimated requirement obligations to customers.

Generation Plant Hedging Information
Estimated Next Three Years
As of March 31, 2005

	Remainder 2005	2006	2007
Estimated Plant Output Hedged	89%	87%	88%

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 March 31, 2005, 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 year-to-date:

VaR Model

Three Months Ended March 31, 2005 (in millions)				Twelve Months Ended December 31, 2004 (in millions)			
End	High	Average	Low	End	High	Average	Low
$2	$5	$2	$1	$3	$19	$5	$1

Our VaR model results are adjusted using standard statistical treatments to calculate the CCRO VaR reporting metrics listed below.

CCRO VaR Metrics
(in millions)

	March 31, 2005	Average for Year-to-Date 2005	High for Year-to-Date 2005	Low for Year-to-Date 2005
95% Confidence Level, Ten-Day Holding Period	$ 8	$ 9	$ 17	$ 5
99% Confidence Level, One-Day Holding Period	$ 3	$ 4	$ 7	$ 2

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 volatilities and correlations were based on three years of daily prices. 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 $653 million at March 31, 2005 and $601 million at December 31, 2004. 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 materially affect our results of operations, cash flows or consolidated financial position.

We employ risk management contracts including physical forward purchase and sale contracts, exchange futures and options, over-the-counter options, swaps, and other derivative contracts to offset price risk where appropriate. We engage in risk management of electricity, gas and to a lesser degree other commodities, principally coal and emissions. As a result, we are subject to price risk. The amount of risk taken is controlled by risk management operations and our Chief Risk Officer and his staff. When risk management activities exceed certain pre-determined limits, the positions are modified or hedged to reduce the risk to be within the limits unless specifically approved by the Risk Executive Committee.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2005 and 2004
(in millions, except per-share amounts)
(Unaudited)

	2005	2004
REVENUES		
Utility Operations	$ 2,537	$ 2,581
Gas Operations	357	652
Other	89	131
TOTAL	2,983	3,364
EXPENSES		
Fuel for Electric Generation	771	694
Purchased Electricity for Resale	130	83
Purchased Gas for Resale	249	585
Maintenance and Other Operation	790	864
Depreciation and Amortization	327	319
Taxes Other Than Income Taxes	188	193
TOTAL	2,455	2,738
OPERATING INCOME	528	626
Other Income	239	62
Other Expense	(66)	(36)
INTEREST AND OTHER CHARGES		
Interest Expense	173	199
Preferred Stock Dividend Requirements of Subsidiaries	2	2
TOTAL	175	201
INCOME BEFORE INCOME TAXES	526	451
Income Taxes	172	162
INCOME BEFORE DISCONTINUED OPERATIONS	354	289
DISCONTINUED OPERATIONS, Net of Tax	1	(7)
NET INCOME	$ 355	$ 282
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING	393	395
EARNINGS PER SHARE		
Income Before Discontinued Operations	$ 0.90	$ 0.73
Discontinued Operations	-	(0.02)
TOTAL EARNINGS PER SHARE (BASIC AND DILUTIVE)	$ 0.90	$ 0.71
CASH DIVIDENDS PAID PER SHARE	$ 0.35	$ 0.35

See Notes to Consolidated Financial Statements

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2005 and December 31, 2004
(in millions)
(Unaudited)

	2005	2004
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,261	$ 320
Other Temporary Cash Investments	181	275
Accounts Receivable:		
Customers	847	930
Accrued Unbilled Revenues	256	592
Miscellaneous	65	79
Allowance for Uncollectible Accounts	(43)	(77)
Total Receivables	1,125	1,524
Fuel, Materials and Supplies	636	852
Risk Management Assets	865	737
Margin Deposits	178	113
Other	157	200
TOTAL	4,403	4,021
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	16,019	15,969
Transmission	6,310	6,293
Distribution	10,378	10,280
Other (including gas, coal mining and nuclear fuel)	3,152	3,585
Construction Work in Progress	1,329	1,159
Total	37,188	37,286
Accumulated Depreciation and Amortization	14,589	14,485
TOTAL - NET	22,599	22,801
OTHER NONCURRENT ASSETS		
Regulatory Assets	3,653	3,601
Securitized Transition Assets	632	642
Spent Nuclear Fuel and Decommissioning Trusts	1,080	1,053
Investments in Power and Distribution Projects	136	154
Goodwill	76	76
Long-term Risk Management Assets	646	470
Prepaid Pension Obligations	385	386
Other	851	831
TOTAL	7,459	7,213
Assets Held for Sale	636	628
TOTAL ASSETS	$ 35,097	$ 34,663

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
March 31, 2005 and December 31, 2004
(Unaudited)

	2005	2004
	(in millions)	
CURRENT LIABILITIES		
Accounts Payable	$ 876	$ 1,051
Short-term Debt	19	23
Long-term Debt Due Within One Year (a)	1,685	1,279
Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption	-	66
Risk Management Liabilities	850	608
Accrued Taxes	865	611
Accrued Interest	171	180
Customer Deposits	469	414
Other	597	775
TOTAL	5,532	5,007
NONCURRENT LIABILITIES		
Long-term Debt (a)	10,674	11,008
Long-term Risk Management Liabilities	470	329
Deferred Income Taxes	4,774	4,819
Regulatory Liabilities and Deferred Investment Tax Credits	2,616	2,540
Asset Retirement Obligations	841	827
Employee Benefits and Pension Obligations	632	730
Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	164	166
Deferred Credits and Other	810	411
TOTAL	20,981	20,830
Liabilities Held for Sale	255	250
TOTAL LIABILITIES	26,768	26,087
Cumulative Preferred Stock Not Subject to Mandatory Redemption	61	61
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDERS' EQUITY		
Common Stock Par Value $6.50:		

	2005	2004
Shares Authorized	600,000,000	600,000,000
Shares Issued	405,433,490	404,858,145

	2005	2004
(21,499,992 and 8,999,992 shares were held in treasury at March 31, 2005 and December 31, 2004, respectively)	2,635	2,632
Paid-in Capital	3,786	4,203
Retained Earnings	2,241	2,024
Accumulated Other Comprehensive Income (Loss)	(394)	(344)
TOTAL	8,268	8,515
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 35,097	$ 34,663

(a) See Accompanying Schedule.

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2005 and 2004
(in millions)
(Unaudited)

	2005	2004
OPERATING ACTIVITIES		
Net Income	$ 355	$ 282
Plus: (Income) Loss from Discontinued Operations	(1)	7
Income from Continuing Operations	354	289
Adjustments for Noncash Items:		
Depreciation and Amortization	327	319
Accretion of Asset Retirement Obligations	18	15
Deferred Income Taxes	(19)	49
Deferred Investment Tax Credits	(8)	(9)
Carrying Costs	(20)	-
Amortization of Deferred Property Taxes	(82)	(93)
Mark-to-Market of Risk Management Contracts	27	(59)
Pension Contributions	(102)	-
Over/Under Fuel Recovery	52	30
Gain on Sales of Assets	(115)	(1)
Change in Other Noncurrent Assets	(66)	2
Change in Other Noncurrent Liabilities	(64)	10
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	104	183
Fuel, Materials and Supplies	64	65
Accounts Payable	39	(95)
Taxes Accrued	245	189
Customer Deposits	55	43
Interest Accrued	(9)	(10)
Other Current Assets	(8)	5
Other Current Liabilities	(119)	(35)
Net Cash Flows From Operating Activities	673	897
INVESTING ACTIVITIES		
Construction Expenditures	(465)	(305)
Change in Other Temporary Cash Investments, Net	94	64
Investment in Discontinued Operations, Net	-	7
Proceeds from Sale of Assets	1,157	40
Other	2	8
Net Cash Flows From (Used For) Investing Activities	788	(186)
FINANCING ACTIVITIES		
Issuance of Common Stock	17	10
Repurchase of Common Stock	(434)	-
Issuance of Long-term Debt	580	73
Change in Short-term Debt, Net	31	(103)
Retirement of Long-term Debt	(510)	(414)
Retirement of Preferred Stock	(66)	(4)
Dividends Paid on Common Stock	(138)	(138)
Net Cash Flows Used For Financing Activities	(520)	(576)
Net Increase in Cash and Cash Equivalents	941	135
Cash and Cash Equivalents at Beginning of Period	320	778
Cash and Cash Equivalents at End of Period	$ 1,261	$ 913
Net Increase in Cash and Cash Equivalents from Discontinued Operations	$ -	$ 24
Cash and Cash Equivalents from Discontinued Operations – Beginning of Period	-	13
Cash and Cash Equivalents from Discontinued Operations – End of Period	$ -	$ 37

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest, net of capitalized amounts, was $170 million and $198 million in 2005 and 2004, respectively. Cash received for income taxes was $57 million in both 2005 and 2004. Noncash acquisitions under capital leases were $9 million and $4 million in 2005 and 2004, respectively.

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2005 and 2004
(in millions)
(Unaudited)

	Common Stock					
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	404	$ 2,626	$ 4,184	$ 1,490	$ (426)	$ 7,874
Issuance of Common Stock	1	4	6			10
Common Stock Dividends				(138)		(138)
TOTAL						7,746
COMPREHENSIVE INCOME						
Other Comprehensive Income, Net of Tax:						
Foreign Currency Translation Adjustments, Net of Tax of $0					8	8
Cash Flow Hedges, Net of Tax of $12					22	22
Minimum Pension Liability, Net of Tax of $10					17	17
NET INCOME				282		282
TOTAL COMPREHENSIVE INCOME						329
MARCH 31, 2004	405	$ 2,630	$ 4,190	$ 1,634	$ (379)	$ 8,075
DECEMBER 31, 2004	405	$ 2,632	$ 4,203	$ 2,024	$ (344)	$ 8,515
Issuance of Common Stock		3	14			17
Common Stock Dividends				(138)		(138)
Repurchase of Common Stock			(434)			(434)
Other			3			3
TOTAL						7,963
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Tax:						
Foreign Currency Translation Adjustments, Net of Tax of $0					1	1
Cash Flow Hedges, Net of Tax of $28					(51)	(51)
NET INCOME				355		355
TOTAL COMPREHENSIVE INCOME						305
MARCH 31, 2005	405	$ 2,635	$ 3,786	$ 2,241	$ (394)	$ 8,268

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SCHEDULE OF CONSOLIDATED LONG-TERM DEBT
March 31, 2005 and December 31, 2004
(Unaudited)

	2005	2004
	(in millions)	
First Mortgage Bonds	$ 417	$ 417
Defeased TCC First Mortgage Bonds (a)	84	84
Installment Purchase Contracts	1,935	1,773
Notes Payable	935	939
Senior Unsecured Notes	7,667	7,717
Securitization Bonds	669	698
Notes Payable to Trust	113	113
Equity Unit Senior Notes	345	345
Long-term DOE Obligation (b)	230	229
Other Long-term Debt	8	14
Equity Unit Contract Adjustment Payments	7	9
Unamortized Discount (net)	(51)	(51)
TOTAL LONG-TERM DEBT OUTSTANDING	12,359	12,287
Less Portion Due Within One Year	1,685	1,279
TOTAL LONG-TERM PORTION	$ 10,674	$ 11,008

(a) On May 7, 2004, we deposited cash and treasury securities of $125 million with a trustee to defease all of TCC's outstanding First Mortgage Bonds. Trust fund assets related to this obligation of $70 and $72 million are included in Other Temporary Cash Investments at March 31, 2005 and December 31, 2004, respectively, and $22 million are included in Other Noncurrent Assets in the Consolidated Balance Sheets at both March 31, 2005 and December 31, 2004. Trust fund assets are restricted for exclusive use in funding the interest and principal due on the First Mortgage Bonds.

(b) Pursuant to the Nuclear Waste Policy Act of 1982, I&M (a nuclear licensee) has an obligation with the United States Department of Energy for spent nuclear fuel disposal. The obligation includes a one-time fee for nuclear fuel consumed prior to April 7, 1983. I&M is the only AEP subsidiary that generated electric power with nuclear fuel prior to that date. Trust fund assets of $261 million and $262 million related to this obligation are included in Spent Nuclear Fuel and Decommissioning Trusts in the Consolidated Balance Sheets at March 31, 2005 and December 31, 2004, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX OF NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING MATTERS

General

The accompanying unaudited interim financial statements should be read in conjunction with the 2004 Annual Report as incorporated in and filed with our 2004 Form 10-K.

In the opinion of management, the unaudited interim financial statements reflect all normal and recurring accruals and adjustments that are necessary for a fair presentation of our results of operations for interim periods.

Other Income and Other Expense

The following table provides the components of Other Income and Other Expense as presented in our Consolidated Statements of Income:

	Three Months Ended March 31,	
	2005	2004
	(in millions)	
Other Income:		
Interest and Dividend Income	$ 11	$ 6
Equity Earnings	5	7
Nonutility Revenue	63	29
Gain on Sale of Texas REPs	112	-
Carrying Charges	20	2
Other	28	18
Total Other Income	$ 239	$ 62
Other Expense:		
Nonutility Expense	$ 57	$ 26
Other	9	10
Total Other Expense	$ 66	$ 36

Components of Accumulated Other Comprehensive Income (Loss)

The following table provides the components that constitute the balance sheet amount in Accumulated Other Comprehensive Income (Loss):

Components	March 31, 2005	December 31, 2004
	(in millions)	
Foreign Currency Translation Adjustments, net of tax	$ 7	$ 6
Securities Available for Sale, net of tax	(1)	(1)
Cash Flow Hedges, net of tax	(51)	-
Minimum Pension Liability, net of tax	(349)	(349)
Total	$ (394)	$ (344)

At March 31, 2005, we expect to reclassify approximately $37 million of net losses from cash flow hedges in Accumulated Other Comprehensive Income (Loss) to Net Income during the next twelve months at the time the hedged transactions affect Net Income. The actual amounts that are reclassified from Accumulated Other Comprehensive Income (Loss) to Net Income can differ as a result of market fluctuations. At March 31, 2005, 21 months is the maximum length of time that we are hedging, with SFAS 133 designated contracts, our exposure to variability in future cash flows for forecasted transactions.

Accounting for Asset Retirement Obligations

The following is a reconciliation of the beginning and ending aggregate carrying amounts of asset retirement obligations:

	Nuclear Decommissioning	Ash Ponds	Wind Mills and Mining Operations	Total
		(in millions)		
Asset Retirement Obligation Liability at January 1, 2005 Including Held for Sale	$ 960	$ 84	$ 32	$ 1,076
Accretion Expense	16	2	-	18
Asset Retirement Obligation Liability at March 31, 2005 Including Held for Sale	976	86	32	1,094
Less Asset Retirement Obligation Liability Held for Sale:				
South Texas Project (a)	(253)	-	-	(253)
Asset Retirement Obligation Liability at March 31, 2005	$ 723	$ 86	$ 32	$ 841

(a) We have signed an agreement to sell TCC's share of South Texas Project (see "Texas Plants-South Texas Project" section of Note 7).

Accretion expense is included in Maintenance and Other Operation expense in our accompanying Consolidated Statements of Income.

At March 31, 2005 and December 31, 2004, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $962 million and $934 million, respectively, of which $819 million and $791 million relating to the Cook Plant was recorded in Spent Nuclear Fuel and Decommissioning Trusts in our Consolidated Balance Sheets. The fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities for South Texas Project totaling $143 million at March 31, 2005 and December 31, 2004, was classified as Assets Held for Sale in our Consolidated Balance Sheets.

Reclassifications

Certain prior period financial statement items have been reclassified to conform to current period presentation. Such reclassifications had no impact on previously reported Net Income.

In connection with preparation of these financial statements, we concluded that it was appropriate to classify our auction rate securities as other temporary cash investments. Previously, such investments had been classified as cash and cash equivalents. Accordingly, we have revised the classification to exclude from cash and cash equivalents $103 million at December 31, 2004, and to include such amounts as other temporary cash investments. There were no auction rate securities held at March 31, 2005. At December 31, 2003, auction rate securities approximated $200 million. In addition, the following represents supplemental disclosures to the Statements of Cash Flows for the three-month periods ended March 31, 2005 and 2004:

	2005	2004
	(in millions)	
Purchases of Auction Rate Securities	$ 785	$ 23
Proceeds from Sale of Auction Rate Securities	888	23

These revisions had no impact on previously reported results of operations, operating cash flows or working capital of the Company.

Prior Period Adjustment

As disclosed in our 2004 Annual Report, in the second quarter of 2004 we implemented FASB Staff Position No. FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003 (FSP FAS 106-2), retroactive to January 1, 2004. The effect of implementing FSP FAS 106-2 on the first quarter of 2004 is as follows:

Three Months Ended March 31, 2004	Net Income (in Millions)		Earnings Per Share	
Originally Reported	$	278	$	0.70
Effect of Medicare Subsidy		4		0.01
Restated	$	282	$	0.71

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of exposure drafts or final pronouncements, we review the new accounting literature to determine the relevance, if any, to our business. The following represents a summary of new pronouncements issued or implemented during 2005 that we have determined relate to our operations.

SFAS 123 (revised 2004) "Share-Based Payment" (SFAS 123R)

In December 2004, the FASB issued SFAS 123R, "Share-Based Payment." SFAS 123R requires entities to recognize compensation expense in an amount equal to the fair value of share-based payments granted to employees. The statement eliminates the alternative to use the intrinsic value method of accounting previously available under Accounting Principles Board (APB) Opinion No. 25. The statement is effective as of the first annual period beginning after June 15, 2005, with early implementation permitted. A cumulative effect of a change in accounting principle is recorded for the effect of initially adopting the statement.

We will implement SFAS 123R in the first quarter of 2006 using the modified prospective method. This method requires us to record compensation expense for all awards we grant after the time of adoption and to recognize the unvested portion of previously granted awards that remain outstanding at the time of adoption as the requisite service is rendered. The compensation cost will be based on the grant-date fair value of the equity award. We do not expect implementation of SFAS 123R to materially affect our results of operations, cash flows or financial condition.

In March 2005, the SEC issued Staff Accounting Bulletin No. 107 (SAB 107), which conveys the SEC staff's views on the interaction between SFAS 123R and certain SEC rules and regulations. SAB 107 also provides the SEC staff's views regarding the valuation of share-based payment arrangements for public companies. We will apply the principles of SAB 107 in conjunction with our adoption of SFAS 123R.

FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47)

In March 2005, the FASB issued FIN 47, which interprets the application of SFAS 143 "Accounting for Asset Retirement Obligations." FIN 47 clarifies that the term conditional asset retirement obligation refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Entities are required to record a liability for the fair value of a conditional asset retirement obligation. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation.

We will implement FIN 47 during the fourth quarter for the fiscal year ending December 31, 2005. Implementation will require an adjustment for the cumulative effect for the nonregulated operations of initially adopting FIN 47 to be recorded as a change in accounting principle, disclosure of pro forma liabilities and asset retirement obligations, and other additional disclosures. We have not completed our evaluation of any potential impact to our results of operations or financial condition.

EITF Issue 03-13 "Applying the Conditions in Paragraph 42 of FASB Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, in Determining Whether to Report Discontinued Operations"

This issue developed a model for evaluating which cash flows are to be considered in determining whether cash flows have been or will be eliminated and what types of continuing involvement constitute significant continuing involvement when determining whether to report Discontinued Operations. During the first quarter of 2005, we applied this issue to components that are disposed of or classified as held for sale, including the HPL disposition. (see "Houston Pipe Line Company" section of Note 7).

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by FASB, we cannot determine the impact on the reporting of our operations that may result from any such future changes. The FASB is currently working on several projects including business combinations, operating segments, liabilities and equity, revenue recognition, pension plans, fair value measurements, accounting changes and related tax impacts. We also expect to see more FASB projects as a result of their desire to converge International Accounting Standards with those generally accepted in the United States of America. The ultimate pronouncements resulting from these and future projects could have an impact on our future results of operations and financial position.

3. RATE MATTERS

As discussed in our 2004 Annual Report, our subsidiaries are involved in rate and regulatory proceedings at the FERC and at state commissions. The Rate Matters note within our 2004 Annual Report should be read in conjunction with this report in order to gain a complete understanding of material rate matters still pending. The following sections discuss current activities and update the 2004 Annual Report.

PSO Fuel and Purchased Power

In 2002, PSO experienced a $44 million under-recovery of fuel costs resulting from a reallocation among AEP West companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO submitted a request to the OCC to collect those costs over 18 months. In August 2003, the OCC Staff filed testimony recommending PSO recover $42 million of the reallocation over three years. In September 2003, the OCC expanded the case to include a full review of PSO's 2001 fuel and purchased power practices.

In the proceeding, parties alleged that the allocation of off-system sales margins between AEP East and AEP West companies were inconsistent with the FERC-approved Operating Agreement and System Integration Agreement and AEP West companies should have received more margins. The OCC expanded the scope of the proceeding to include the off-system sales margin issue for the year 2002 and an intervenor filed a motion to expand the scope to review this same issue for the years 2003 and 2004. Using the intervenors' method, PSO estimates that the increase in margins would be $29 million through March 31, 2005. In April 2005, the OCC heard arguments from intervenors that requested the OCC to conduct a prudence review of PSO's fuel and purchased power for 2003. Management is unable to predict if the OCC will order a prudence review of PSO's fuel and purchased power activities for 2003 or the ultimate effect of these proceedings on our revenues, results of operations, cash flows and financial condition.

Michigan Fuel Recovery Plan

In September 2004, I&M filed its 2005 Power Supply Cost Recovery (PSCR) Plan, with the requested PSCR factors implemented pursuant to the statute effective with January 2005 billings, replacing the 2004 factors. On March 29, 2005, the Michigan Public Service Commission (MPSC) issued an order approving a settlement agreement authorizing the proposed 2005 PSCR Plan factors.

On March 31, 2005, I&M filed its 2004 PSCR Reconciliation seeking recovery of approximately $2 million of unrecovered PSCR fuel costs and interest proposed to be recovered through the application of customer bill surcharges during October 2005 through December 2005.

On April 28, 2005, the MPSC issued an Opinion and Order approving I&M's proposed 2004 PSCR factors as billed and finding in favor of I&M on all issues, including the proposed treatment of net SO_2 and NO_x credits.

Indiana Settlement Agreement

In 2004, the IURC ordered the continuation of the fixed fuel adjustment charge on an interim basis through March 2005, pending the outcome of negotiations. Certain of the parties to the negotiations reached a settlement and signed an agreement on March 10, 2005, and filed the agreement with the IURC on March 14, 2005. The IURC may rule on the agreement during the second quarter of 2005.

The filed settlement freezes fuel rates for the March 2004 through June 2007 billing months at an increasing rate that includes 8.609 mills per KWH reflected in base rates. The settlement provides that the total fuel rates will be 9.88 mills per KWH from January 2005 through December 2005, 10.26 mills per KWH from January 2006 through December 2006, and 10.63 mills per KWH from January 2007 through June 2007. Pursuant to a separate IURC order, I&M began billing the 9.88 mills per KWH total fuel rate on an interim basis effective with the April 2005 billing month.

The settlement agreement also covers certain events at the Cook Plant. The settlement provides that if an outage greater than 60 days occurs at Cook Plant, the recovery of actual monthly fuel costs will be in effect for the outage period beyond 60 days, capped by the average AEP System Pool Primary Energy Rate (Primary Energy Rate), excluding I&M, as defined by the AEP System Interconnection Agreement and adjusted for losses. If a second outage greater than 60 days occurs, actual monthly fuel costs capped at the Primary Energy Rate would be recovered through June 2007. Over the term of the settlement, if total actual fuel costs (except during a Cook Plant outage greater than 60 days) are under the cap prices, the excess will be credited to customers over the next two fuel adjustment clause filings. Under the settlement fuel costs in excess of the cap price cannot be recovered. If Cook Plant operates at a capacity factor greater than 87% during the fuel rate freeze period, I&M will receive credit for 30% of the savings produced and customers will be credited with 70% of these savings over the first two fuel filings after the fuel rate freeze period ends in June 2007.

Pending approval of the IURC, this settlement agreement also freezes base rates from January 1, 2005 to June 30, 2007 at the rates in effect as of January 1, 2005. During this freeze period, I&M may not implement a general increase in base rates or implement a rider or cost deferral not established in the settlement agreement unless the IURC determines that a significant change in conditions beyond I&M's control occurs or a material impact on I&M occurs as a result of federal, state or local regulation or statute that mandates reliability standards related to transmission or distribution costs.

If the settlement is approved by the IURC, fuel costs previously expensed since January 2005 exceeding the previously authorized level of 9.2 mills up to 9.88 mills (approximately $4 million through March 31, 2005) would be deferred for future recovery. If future fuel cost per KWH exceeds the caps, or if the base rate freeze precludes I&M from seeking timely rate increases to recover increases in I&M's cost of service, future results of operations and cash flows would be adversely affected.

TCC Rate Case

TCC has an on-going transmission and distribution (T&D) rate review before the PUCT. In that rate review, the PUCT has issued various decisions and conducted additional hearings in March 2005. At an open meeting on April 13, 2005, the PUCT decided all remaining issues except the amount of affiliate expenses to include in revenue requirements which the PUCT decided to defer. Adjusted for the decisions approved by the PUCT through April 13, 2005, the ALJ's recommended disallowances of affiliate expenses would produce an annual rate reduction of $25 million to $52 million. If TCC were to prevail on the affiliate expenses issue, the result would be an annual rate increase of $2 million. An order reducing TCC's rates could have an adverse effect on future results of operations and cash flows.