

AMERICAN ELECTRIC POWER CO INC
Form 10-Q
August 04, 2006

**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q**

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended **June 30, 2006**
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 No

Indicate by check mark whether American Electric Power Company, Inc. is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of 'accelerated filer and large accelerated filer' in Rule 12b-2 of the Exchange Act. (Check One)

Large accelerated filer Accelerated filer Non-accelerated filer

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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 large accelerated filers, accelerated filers, or non-accelerated filers. See definition of 'accelerated filer and large accelerated filer' in Rule 12b-2 of the Exchange Act. (Check One)

Large accelerated filer *Accelerated filer* *Non-accelerated filer*

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Exchange Act).

Yes *No*

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.

| | Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants as of June 30, 2006, the last trading date of the registrants' most recently completed second fiscal quarter | Number of shares of common stock outstanding of the registrants at July 31, 2006 |
|--|---|---|
| AEP Generating Company | None | 1,000 (\$1,000 par value) |
| AEP Texas Central Company | None | 2,211,678 (\$25 par value) |
| AEP Texas North Company | None | 5,488,560 (\$25 par value) |
| American Electric Power Company, Inc. | \$13,492,667,933 | 393,975,064 (\$6.50 par value) |
| Appalachian Power Company | None | 13,499,500 (no par value) |
| Columbus Southern Power Company | None | 16,410,426 (no par value) |
| Indiana Michigan Power Company | None | 1,400,000 (no par value) |
| Kentucky Power Company | None | 1,009,000 (\$50 par value) |
| Ohio Power Company | None | 27,952,473 (no par value) |
| Public Service Company of Oklahoma | None | 9,013,000 (\$15 par value) |
| Southwestern Electric Power Company | None | 7,536,640 (\$18 par value) |

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
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June 30, 2006

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Appalachian Power Company and Subsidiaries:

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Indiana Michigan Power Company and Subsidiaries:

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Management's Narrative Financial Discussion and Analysis
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Ohio Power Company Consolidated:

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Public Service Company of Oklahoma:

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Southwestern Electric Power Company Consolidated:

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SIGNATURE

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 |
|---|--|
| ADFIT | Accumulated Deferred Federal Income Taxes. |
| ADITC | Accumulated Deferred Investment Tax Credits. |
| AEGCo | AEP Generating Company, an AEP electric generating subsidiary. |
| AEP or Parent | American Electric Power Company, Inc. |
| AEP Consolidated | AEP and its majority owned consolidated subsidiaries and consolidated entities. |
| 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 | American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility 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. |
| AEPSC | American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries. |
| AEP West companies | PSO, SWEPCo, TCC and TNC. |
| AFUDC | Allowance for Funds Used During Construction. |
| ALJ | Administrative Law Judge. |
| APCo | Appalachian Power Company, an AEP electric utility subsidiary. |
| CAA | Clean Air Act. |
| Cook Plant | Donald C. Cook Nuclear Plant, a two-unit, 2,110 MW nuclear plant owned by I&M. |
| CSPCo | Columbus Southern Power Company, an AEP electric utility subsidiary. |
| CSW | Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.). |
| CSW Operating Agreement | Agreement, dated January 1, 1997, by and among PSO, SWEPCo, TCC and TNC governing their generating capacity allocation. AEPSC acts as the agent. |
| CTC | Competition Transition Charge. |
| DETM | Duke Energy Trading and Marketing L.L.C., a risk management counterparty. |
| EDFIT | Excess Deferred Federal Income Taxes. |
| EITF | Financial Accounting Standards Board's Emerging Issues Task Force. |
| EPACT | Energy Policy Act of 2005. |
| ERCOT | Electric Reliability Council of Texas. |
| FASB | Financial Accounting Standards Board. |
| Federal EPA | United States Environmental Protection Agency. |

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| | |
|---------------------------|---|
| FERC | Federal Energy Regulatory Commission. |
| GAAP | Accounting Principles Generally Accepted in the United States of America. |
| HPL | Houston Pipe Line Company LP, a former AEP subsidiary that was sold in January 2005. |
| IGCC | Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas. |
| I&M | Indiana Michigan Power Company, an AEP electric utility subsidiary. |
| IRS | Internal Revenue Service. |
| IPP | Independent Power Producers. |
| IURC | Indiana Utility Regulatory Commission. |
| KPCo | Kentucky Power Company, an AEP electric utility subsidiary. |
| KPSC | Kentucky Public Service Commission. |
| kV | Kilovolt. |
| KWH | Kilowatthour. |
| MISO | Midwest Independent Transmission System Operator. |
| MTM | Mark-to-Market. |
| MW | Megawatt. |
| MWH | Megawatthour. |
| NO _x | Nitrogen oxide. |
| Nonutility Money Pool | AEP System's Nonutility Money Pool. |
| NRC | Nuclear Regulatory Commission. |
| NSR | New Source Review. |
| NYMEX | New York Mercantile Exchange. |
| OATT | Open Access Transmission Tariff. |
| OCC | Corporation Commission of the State of Oklahoma. |
| 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. |
| PTB | Price-to-Beat. |
| PUCO | Public Utilities Commission of Ohio. |
| PUCT | Public Utility Commission of Texas. |
| PURPA | Public Utility Regulatory Policies Act of 1978. |
| Registrant Subsidiaries | AEP subsidiaries which 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 FASB. |
| SFAS 133 | Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities." |
| SIA | System Integration Agreement. |

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| | |
|---------------------------------|--|
| SO ₂ | Sulfur Dioxide. |
| SPP | Southwest Power Pool. |
| STP | South Texas Project Nuclear Generating Plant. |
| Sweeny | Sweeny Cogeneration Limited Partnership, owner and operator of a four unit, 480 MW gas-fired generation facility, owned 50% by AEP. |
| SWEPCo | Southwestern Electric Power Company, an AEP electric utility subsidiary. |
| TCC | AEP Texas Central Company, an AEP electric utility subsidiary. |
| TEM | SUEZ Energy Marketing NA, Inc. (formerly known as Tractebel Energy Marketing, Inc.). |
| 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 made under the Texas Restructuring Legislation to finalize the amount of stranded costs and other true-up items and the recovery of such amounts. |
| 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. |
| WPCo | Wheeling Power Company, an AEP electric distribution subsidiary. |
| WVPSC | Public Service Commission of West Virginia. |

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.
- Our ability to recover regulatory assets and stranded costs in connection with deregulation.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases or competitive 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).
- Resolution of litigation (including pending Clean Air Act enforcement actions and disputes arising from the bankruptcy of Enron Corp. and related matters).
- Our ability to constrain operation and maintenance costs.
- Our ability to sell assets at acceptable prices and other acceptable terms.
- The economic climate and growth in our service territory and changes in market demand and demographic patterns.
- Inflationary and interest rate 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 of the counterparties with whom we have contractual arrangements, including 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 implementation of EPACT and membership in 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, particularly with respect to new, developing or alternative sources of generation.
- 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

Several factors contributed to our positive performance in the second quarter of 2006. We received favorable outcomes in various regulatory activities causing increased revenues. We also continued to win new power supply contracts with municipal and cooperative customers and our barging subsidiary is producing strong results. Some of these positive factors were offset in part by mild weather and increased fuel costs.

Regulatory Activity

Our significant regulatory activity progressed with the following major developments:

- In April 2006, the PUCO approved our recovery of the pre-construction costs for the IGCC clean-coal plant in Meigs County, Ohio. We subsequently submitted tariffs and received PUCO approval to recover \$24 million of our IGCC pre-construction costs beginning July 1, 2006.
- In May 2006, we filed a base rate case in Virginia requesting a net rate increase of \$198 million. Rates will be effective, subject to refund, on October 2, 2006.
- In May 2006, the PUCO approved a two-step increase in transmission rates with an over/under recovery mechanism effective April 1, 2006. We subsequently submitted tariffs and received PUCO approval to implement the rates in June 2006. We expect this order to increase 2006 revenues by \$63 million.
- In June 2006, we received a financing order from the PUCT to issue \$1.7 billion in securitization bonds. We anticipate issuing the bonds and receiving the proceeds by the end of September 2006. We intend to use the proceeds to reduce a portion of TCC's debt and equity, which would include a dividend payment to AEP.
- In July 2006, an ALJ rendered an initial decision to the FERC recommending that current transmission rates in PJM are unjust and unreasonable and should be redesigned to replace the PJM license plate rates effective April 1, 2006. If approved by the FERC, the new regional rates should result in parties outside of the AEP zone in PJM contributing a significant portion of AEP's transmission revenue requirement, some of which may be treated as a credit to retail customers. The favorable impact of the initial ALJ decision is not determinable pending the decision of the FERC and subject to analysis of credits to retail customers, if any.
- In July 2006, the FERC approved our request for use of an incentive rate treatment for our proposed 550-mile I-765 transmission line project. The approval is conditioned upon PJM including the project in its formal Regional Transmission Expansion Plan, which should be finalized in 2006 or early 2007.
- In July 2006, the West Virginia Public Service Commission approved a settlement agreement in APCo and WPCo's base rate case, providing for a \$44 million annual increase in rates effective July 28, 2006. These rates include a surcharge for recovery of the cost of the Wyoming-Jacksons Ferry 765 kV line, which was energized and placed in service in June 2006.

Fuel Costs

During 2006, spot market prices for coal and natural gas have softened. In contrast, market prices for fuel oil have continued to increase. However, even considering softening fuel markets and favorable transportation effects during the first half of the year, we still expect an approximate eleven percent increase in coal costs during 2006, and we have price risk related to these commodity prices. More specifically, we do not have active fuel cost recovery adjustment mechanisms in Indiana and Ohio, which represents approximately 20% of our fuel costs.

In Indiana, our fuel recovery mechanism is temporarily capped, subject to preestablished escalators, at a fixed rate through June 2007. As a consequence of the cap, we incurred under-recoveries of \$12 million for the first six months of 2006 and expect additional under-recoveries for the remainder of 2006. Our Ohio companies increased their generation rates in 2006, as previously approved by the PUCO in our Rate Stabilization Plans, which are presently subject to an Ohio Supreme Court remand. These increased rates, along with the reinstated fuel cost adjustment rate clause for over- or under-recovery of fuel and related costs effective July 1, 2006 in West Virginia, will help offset future negative impacts of fuel prices on our gross margins.

Barging Operations

During 2006, we have achieved favorable results in our Investments - Other segment primarily due to our barging operations. AEP MEMCO LLC (MEMCO) handles the dispatching and logistics for our river operations, which consists primarily of coal deliveries to our plants, coal movement between plants for ensuring continued operations when market disruptions occur and transportation of bargeable commodities for third parties. MEMCO continues to benefit from strong market demand for barging services as well as a tight supply of barges, which allowed it to negotiate very favorable annual freight contracts for 2006 and beyond for hauling a variety of commodities for third parties. The strong freight market, enhanced operating conditions when compared with the flooding and ice encountered during the first quarter of 2005 and the continued implementation of programs to maximize equipment use all contribute to an increase in tonnage transported and a related increase in earnings.

Stock Option Grant Practices

Our internal audit function recently completed a review of our stock option grant practices. The review was initiated as a matter of prudence resulting from our desire to ensure we had not engaged in the kinds of past practices that have recently received adverse publicity and resulted in investigations of other companies. Our internal auditors found no indication of backdating or special option grant timing.

RESULTS OF OPERATIONS

Segments

Our principal operating business segments and their major activities are:

Utility Operations

- Generation of electricity for sale to U.S. retail and wholesale customers.
- Electricity transmission and distribution in the U.S.

Investments - Other

- Bulk commodity barging operations, wind farms, IPPs and other energy supply-related businesses.

Our consolidated Income Before Discontinued Operations for the three and six months ended June 30, 2006 and 2005 were as follows (Earnings and Weighted Average Basic Shares Outstanding in millions):

Three Months Ended June 30,

Six Months Ended June 30,

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| | 2006 | | 2005 | | 2006 | | 2005 | |
|--|---------------|----------------|---------------|----------------|---------------|----------------|---------------|----------------|
| | Earnings | EPS (c) | Earnings | EPS (c) | Earnings | EPS (c) | Earnings | EPS (c) |
| Utility Operations | \$ 160 | \$ 0.41 | \$ 247 | \$ 0.64 | \$ 525 | \$ 1.33 | \$ 600 | \$ 1.54 |
| Investments - Other | 13 | 0.03 | (1) | - | 29 | 0.08 | 4 | 0.01 |
| All Other (a) | (3) | - | (26) | (0.06) | (5) | (0.01) | (40) | (0.10) |
| Investments - Gas Operations (b) | 2 | - | (2) | (0.01) | 1 | - | 8 | 0.02 |
| Income Before Discontinued Operations | \$ 172 | \$ 0.44 | \$ 218 | \$ 0.57 | \$ 550 | \$ 1.40 | \$ 572 | \$ 1.47 |
| Weighted Average Number of Basic Shares Outstanding | | | | | | | | |
| | | 394 | | 384 | | 394 | | 389 |

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

(b) We sold our remaining gas pipeline and storage assets in 2005.

(c) The earnings per share of any segment does not represent a direct legal interest in the assets and liabilities allocated to any one segment but rather represents a direct equity interest in AEP's assets and liabilities as a whole.

Second Quarter of 2006 Compared to Second Quarter of 2005

Income Before Discontinued Operations in the second quarter of 2006 decreased \$46 million compared to the second quarter of 2005 due to an \$87 million decrease in Utility Operations earnings primarily related to decreases in off-system sales and transmission revenues and increases in operating expenses, partially offset by new rates implemented in Ohio and Kentucky. The decrease in Utility Operations earnings was partially offset by an earnings increase of \$14 million in our Investments - Other segment primarily related to favorable results in our barging operations and a decrease of \$23 million in All Other related to interest expense, net of interest income, at the parent company.

Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2005

Income Before Discontinued Operations for the six months ended June 30, 2006 decreased \$22 million compared to the six months ended June 30, 2005 due to a \$75 million decrease in Utility Operations earnings primarily related to decreases in off-system sales and transmission revenues and increases in operating expenses, partially offset by new rates implemented in Ohio and Kentucky. The decrease in Utility Operations earnings was partially offset by an earnings increase of \$25 million in our Investments - Other segment primarily related to favorable results in our barging operations and a decrease of \$35 million in interest expense, net of interest income, at the parent company.

Our results of operations are discussed below according to our operating segments.

Utility Operations

Our Utility Operations include primarily regulated revenues with direct and variable offsetting expenses and net reported commodity trading operations. We believe that a discussion of the results from our Utility Operations segment on a gross margin basis is most appropriate. Gross margins represent utility operating revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power.

**Three Months Ended
June 30,**

**Six Months Ended
June 30,**

| | 2006 | 2005 | 2006 | 2005 |
|--|---------------|---------------|---------------|---------------|
| | (in millions) | | | |
| Revenues | \$ 2,799 | \$ 2,702 | \$ 5,768 | \$ 5,386 |
| Fuel and Purchased Energy | 1,126 | 988 | 2,253 | 1,911 |
| Gross Margin | 1,673 | 1,714 | 3,515 | 3,475 |
| Depreciation and Amortization | 339 | 317 | 672 | 635 |
| Other Operating Expenses | 987 | 938 | 1,833 | 1,743 |
| Operating Income | 347 | 459 | 1,010 | 1,097 |
| Other Income, Net | 43 | 49 | 85 | 79 |
| Interest Expense and Preferred Stock Dividend Requirements | 160 | 156 | 314 | 300 |
| Income Tax Expense | 70 | 105 | 256 | 276 |
| Income Before Discontinued Operations | \$ 160 | \$ 247 | \$ 525 | \$ 600 |

**Summary of Selected Sales and Weather Data
For Utility Operations
For the Three and Six Months Ended June 30, 2006 and 2005**

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|------------------------|--------------------------------|--------|------------------------------|---------|
| | 2006 | 2005 | 2006 | 2005 |
| | (in millions of KWH) | | | |
| Energy Summary | | | | |
| Retail: | | | | |
| Residential | 9,590 | 9,956 | 22,528 | 23,180 |
| Commercial | 9,440 | 9,573 | 18,349 | 18,305 |
| Industrial | 13,716 | 13,480 | 26,937 | 26,253 |
| Miscellaneous | 625 | 639 | 1,214 | 1,284 |
| Subtotal | 33,371 | 33,648 | 69,028 | 69,022 |
| Texas Retail and Other | 138 | 161 | 206 | 389 |
| Total Retail | 33,509 | 33,809 | 69,234 | 69,411 |
| Wholesale | 10,822 | 11,745 | 21,667 | 24,380 |
| Texas Wires Delivery | 6,915 | 6,736 | 12,461 | 12,254 |
| Total KWHs | 51,246 | 52,290 | 103,362 | 106,045 |

Cooling degree days and heating degree days are metrics commonly used in the utility industry as a measure of the impact of weather on results of operations. In general, degree day changes in our eastern region have a larger effect on results of operations than changes in our western region due to the relative size of the two regions and the associated number of customers within each. Cooling degree days and heating degree days in our service territory for the quarter and year-to-date periods ended June 30, 2006 and 2005 were as follows:

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|--|--------------------------------|------|------------------------------|------|
| | 2006 | 2005 | 2006 | 2005 |
| | (in degree days) | | | |

Weather Summary
Eastern Region

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| | | | | |
|---------------------------|-----|-----|-------|-------|
| Actual - Heating (a) | 107 | 165 | 1,563 | 1,939 |
| Normal - Heating (b) | 175 | 177 | 1,992 | 1,988 |
| Actual - Cooling (c) | 228 | 288 | 229 | 288 |
| Normal - Cooling (b) | 279 | 278 | 282 | 281 |
| Western Region (d) | | | | |
| Actual - Heating (a) | 5 | 26 | 663 | 795 |
| Normal - Heating (b) | 33 | 33 | 1,005 | 1,005 |
| Actual - Cooling (c) | 815 | 681 | 858 | 701 |
| Normal - Cooling (b) | 652 | 644 | 669 | 662 |

- (a) Eastern Region and Western Region heating degree days are calculated on a 55 degree temperature base.
 (b) Normal Heating/Cooling represents the 30-year average of degree days.
 (c) Eastern Region and Western Region cooling days are calculated on a 65 degree temperature base.
 (d) Western Region statistics represent PSO/SWEPCo customer base only.

Second Quarter of 2006 Compared to Second Quarter of 2005

**Reconciliation of Second Quarter of 2005 to Second Quarter of 2006
 Income from Utility Operations Before Discontinued Operations
 (in millions)**

| | |
|---|---------------|
| Second Quarter of 2005 | \$ 247 |
| Changes in Gross Margin: | |
| Retail Margins | 56 |
| Off-system Sales | (49) |
| Transmission Revenues | (55) |
| Other | 7 |
| Total Change in Gross Margin | (41) |
| Changes in Operating Expenses and Other: | |
| Maintenance and Other Operation | (34) |
| Depreciation and Amortization | (22) |
| Taxes Other Than Income Taxes | (15) |
| Other Income, Net | (6) |
| Interest and Other Charges | (4) |
| Total Change in Operating Expenses and Other | (81) |
| Income Tax Expense | 35 |
| Second Quarter of 2006 | \$ 160 |

Income from Utility Operations Before Discontinued Operations decreased \$87 million to \$160 million in 2006. The key drivers of the decrease were a \$41 million net decrease in Gross Margin and an \$81 million increase in Operating Expenses and Other, partially offset by a \$35 million decrease in Income Tax Expense.

The major components of the net decrease in Gross Margin were as follows:

- Retail Margins increased \$56 million primarily due to the following:
 - A \$55 million increase related to new rates implemented in our Ohio jurisdictions as approved by the PUCO in our Rate Stabilization Plans (RSPs) and a \$10 million increase related to new rates implemented in Kentucky as approved in our base rate case;
 - A \$30 million increase in financial transmission rights revenue, net of congestion costs, due to improved management of price risk related to serving retail load within PJM under current transmission constraints;
 - An \$18 million increase related to reduced off-system sales margins shared with customers due to lower off-system sales; and
 - A \$14 million increase related to increased usage and customer growth in the industrial and commercial classes of which \$11 million relates to the purchase of the Ohio service territory of Monongahela Power in December 2005; partially offset by
 - A \$68 million increase in delivered fuel costs, which relates to the AEP East companies with inactive, capped or frozen fuel clauses; and
 - An \$11 million decrease in usage related to mild weather. As compared to the prior year, our eastern region experienced a 21% decrease in cooling degree days, partially offset by a 20% increase in cooling degree days in the western region.
- Margins from Off-system Sales for 2006 decreased \$49 million due to lower volumes in part from the sale of STP in May 2005, a forced outage in 2006 at the Oklaunion plant, various eastern fleet outages in 2006 for boiler tube inspections and lower optimization activities.
- Transmission Revenues decreased \$55 million primarily due to the elimination of SECA revenues as of April 1, 2006 and a provision of \$18 million recorded in the second quarter of 2006 related to potential SECA refunds pending settlement negotiations with various intervenors. At this time, SECA revenues have not been replaced. See the "SECA Revenue Subject to Refund" section of Note 3.

Utility Operating Expenses and Other and Income Taxes changed between years as follows:

- Maintenance and Other Operation expenses increased \$34 million primarily due to increases in generation expenses for planned and forced plant outages, increases in transmission and distribution expenses related to tree trimming and storm restoration and the establishment of a regulatory asset for PJM administrative fees in 2005 which reduced expenses in the prior period, offset by decreases related to the sale of STP in May 2005.
- Depreciation and Amortization expense increased \$22 million primarily due to increased Ohio regulatory asset amortization in conjunction with rate increases as well as higher depreciable property balances.
- Taxes Other Than Income Taxes increased \$15 million primarily due to increased real and personal property taxes.
- Income Tax Expense decreased \$35 million due to the decrease in pretax income.

Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2005

**Reconciliation of Six Months Ended June 30, 2005 to Six Months Ended June 30, 2006
Income from Utility Operations Before Discontinued Operations
(in millions)**

| | |
|---|---------------|
| Six Months Ended June 30, 2005 | \$ 600 |
| Changes in Gross Margin: | |
| Retail Margins | 168 |
| Off-system Sales | (73) |
| Transmission Revenues | (54) |
| Other | (1) |
| Total Change in Gross Margin | 40 |
| Changes in Operating Expenses and Other: | |
| Maintenance and Other Operation | (28) |
| Gain on Sales of Assets, Net | (46) |
| Depreciation and Amortization | (37) |
| Taxes Other Than Income Taxes | (16) |
| Other Income, Net | 6 |
| Interest and Other Charges | (14) |
| Total Change in Operating Expenses and Other | (135) |
| Income Tax Expense | 20 |
| Six Months Ended June 30, 2006 | \$ 525 |

Income from Utility Operations Before Discontinued Operations decreased \$75 million to \$525 million in 2006. The key driver of the decrease was a \$135 million increase in Operating Expenses and Other, offset by a \$40 million increase in Gross Margin and a \$20 million decrease in Income Tax Expense.

The major components of the net increase in Gross Margin were as follows:

- Retail Margins increased \$168 million primarily due to the following:
 - A \$103 million increase related to new rates implemented in our Ohio jurisdictions as approved by the PUCO in our RSPs, a \$10 million increase related to new rates implemented in Kentucky as approved in our base rate case and a \$7 million increase related to new rates implemented in Oklahoma in June 2005;
 - A \$76 million increase in financial transmission rights revenue, net of congestion costs, due to improved management of price risk related to serving retail load within PJM under current transmission constraints;
 - A \$41 million increase related to increased usage and customer growth in the industrial and commercial classes of which \$21 million relates to the purchase of the Ohio service territory of Monongahela Power in December 2005;
 - An \$18 million increase related to reduced off-system sales margins shared with customers due to lower off-system sales; and
 - A \$29 million increase related to increased sales to municipal, cooperative and other wholesale customers primarily as a result of new power supply contracts; partially offset by
 - A \$109 million increase in delivered fuel cost, which relates to AEP East companies with inactive, capped or frozen fuel clauses; and
 - A \$37 million decrease in usage related to mild weather. As compared to the prior year, our eastern region and western region experienced 19% and 17% declines, respectively, in heating degree days. These decreases were

partially offset by an increase of 22% in cooling degree days in the western region.

- Margins from Off-system Sales for 2006 were \$73 million lower than in 2005 due to lower volumes in part from the sale of STP in May 2005, a forced outage in 2006 at the Oklaunion plant, various eastern fleet outages in 2006 for boiler tube inspections and lower optimization activities.
- Transmission Revenues decreased \$54 million primarily due to the elimination of SECA revenues as of April 1, 2006 and a provision of \$19 million recorded in 2006 related to potential SECA refunds pending settlement negotiations with various intervenors. At this time, SECA revenues have not been replaced. See the “SECA Revenue Subject to Refund” section of Note 3.

Utility Operating Expenses and Other and Income Taxes changed between years as follows:

- Maintenance and Other Operation expenses increased \$28 million primarily due to increases in generation expenses related to base operations, maintenance and planned and forced plant outages, distribution expenses related to tree trimming and the establishment of a regulatory asset for PJM administrative fees in 2005 which reduced expenses in the prior period, offset by favorable variances related to expenses from the January 2005 ice storm in Ohio and Indiana and decreases related to the sale of STP in May 2005.
- Gain on Sales of Assets, Net decreased \$46 million resulting from 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. In 2005, we reached a settlement with Centrica and received \$112 million related to two years of earnings sharing whereas in 2006 we received \$70 million related to one year of earnings sharing.
- Depreciation and Amortization expense increased \$37 million primarily due to increased Ohio regulatory asset amortization in conjunction with rate increases as well as higher depreciable property balances.
- Taxes Other Than Income Taxes increased \$16 million primarily due to increased real and personal property taxes.
- Interest and Other Charges increased \$14 million from the prior period primarily due to additional debt issued in late 2005 and early 2006 and increasing interest rates.
- Income Tax Expense decreased \$20 million due to the decrease in pretax income.

Investments - Other

Second Quarter of 2006 Compared to Second Quarter of 2005

Income Before Discontinued Operations from our Investments - Other segment increased from a loss of \$1 million in 2005 to income of \$13 million in 2006. The increase was primarily due to favorable barging activity at MEMCO due to strong demand and a tight supply of barges, resulting in increased barge freight rates.

Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2005

Income Before Discontinued Operations from our Investments - Other segment increased \$25 million primarily due to favorable barging activity at MEMCO due to strong demand and a tight supply of barges which increased barge freight rates. Additionally, the first quarter of 2006 operating conditions for our barging operations improved from 2005 when severe ice and flooding caused increased operating costs.

Other

Parent

Second Quarter of 2006 Compared to Second Quarter of 2005

The parent company's Loss before Discontinued Operations decreased \$23 million from 2005 primarily due to lower interest expense and associated buyback costs related to the redemption of \$550 million of senior unsecured notes in April 2005 and increased affiliated interest income related to favorable results from the corporate borrowing program.

Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2005

The parent company's Loss before Discontinued Operations decreased \$35 million from 2005 primarily due to lower interest expense and associated buyback costs related to the redemption of \$550 million of senior unsecured notes in April 2005 and increased affiliated interest income related to favorable results from the corporate borrowing program.

*Investments - Gas Operations***Second Quarter of 2006 Compared to Second Quarter of 2005**

Income Before Discontinued Operations from our Gas Operations segment increased from a loss of \$2 million in 2005 to income of \$2 million in 2006. The increase primarily relates to a true-up adjustment in the second quarter of 2006 related to the Enron litigation settled in the fourth quarter of 2005. Current year results also relate to gas contracts that were not sold with the gas pipeline and storage assets.

Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2005

Income Before Discontinued Operations from our Gas Operations segment of \$1 million in 2006 compares with \$8 million of income recorded for 2005. Prior year results included one month of HPL's operations due to the sale of HPL in January 2005. Current year results relate to gas contracts that were not sold with the gas pipeline and storage assets.

AEP System Income Taxes

The decrease in income tax expense of \$31 million between the second quarter of 2006 and the second quarter of 2005 is primarily due to a decrease in pretax book income.

The decrease in income tax expense of \$14 million between the six months ended June 30, 2006 and the six months ended June 30, 2005 is primarily due to a decrease in pretax book income.

FINANCIAL CONDITION

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

Debt and Equity Capitalization (\$ in millions)

| | June 30, 2006 | | December 31, 2005 | | |
|---|---------------|---------------|-------------------|---------------|---------------|
| Long-term Debt, including amounts due within one year | \$ | 12,645 | 56.7% \$ | 12,226 | 57.2% |
| Short-term Debt | | 159 | 0.7 | 10 | 0.0 |
| Total Debt | | 12,804 | 57.4 | 12,236 | 57.2 |
| Common Equity | | 9,426 | 42.3 | 9,088 | 42.5 |
| Preferred Stock | | 61 | 0.3 | 61 | 0.3 |
| Total Debt and Equity Capitalization | \$ | 22,291 | 100.0% \$ | 21,385 | 100.0% |

The amount of our common equity increased primarily due to earnings exceeding the amount of dividends paid in 2006. However, as a consequence of increasing debt for capital investment during 2006, our ratio of total debt to total capital increased from 57.2% to 57.4%.

The FASB's current pension and postretirement benefit accounting project could have a major negative impact on our debt to capital ratio in future years. The potential change could require the recognition of an additional minimum liability for fully-funded pension and postretirement benefit plans, thereby eliminating on the balance sheet the SFAS 87 and SFAS 106 deferral and amortization of net actuarial gains and losses. If adopted, this could require recognition of a significant net-of-tax accumulated other comprehensive income reduction to common equity for those regulatory jurisdictions where a regulatory asset cannot be recorded. The proposed effective date is fiscal years ending after December 15, 2006. We cannot predict the ultimate effects of the final amendment if adopted.

Liquidity

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

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. At June 30, 2006, our available liquidity was approximately \$3.1 billion as illustrated in the table below:

| | Amount (in millions) | Maturity |
|--|---------------------------------|-----------------|
| Commercial Paper Backup: | | |
| Revolving Credit Facility | \$ 1,500 | March 2010 |
| Revolving Credit Facility | 1,500 | April 2011 |
| Total | 3,000 | |
| Cash and Cash Equivalents | 249 | |
| Total Liquidity Sources | 3,249 | |
| Less: AEP Commercial Paper Outstanding | 144 | |
| Letter of Credit Drawn | 31 | |
| Net Available Liquidity | \$ 3,074 | |

In April 2006, we amended the terms and increased the size of our credit facilities from \$2.7 billion to \$3 billion on terms more economically favorable than the previous agreements. The amended facilities are structured as two \$1.5 billion credit facilities, each with an option to issue up to \$200 million as letters of credit.

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 June 30, 2006, this contractually-defined percentage was 54.4%. Nonperformance of these covenants could result in an event of default under these credit agreements. At June 30, 2006, we complied with all of 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 outstanding amounts payable.

The two amended revolving credit facilities do not contain a material adverse change clause.

Under a regulatory order, 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 the 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 June 30, 2006, all utility subsidiaries were comfortably in compliance with this order.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. At June 30, 2006, our utility subsidiaries had not exceeded those authorized limits.

Credit Ratings

AEP's ratings have not been adjusted by any rating agency during 2006 and AEP is currently on a stable outlook by the rating agencies. Our current credit ratings are as follows:

| | Moody's | S&P | Fitch |
|---------------------------|----------------|----------------|--------------|
| AEP Short Term Debt | P-2 | A-2 | F-2 |
| AEP Senior Unsecured Debt | Baa2 | BBB | BBB |

If we or any of our 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 rating agencies listed above, our borrowing costs could increase and access to borrowed funds could be negatively affected.

Cash Flow

Managing our cash flows is a major factor in maintaining our liquidity strength.

| | Six Months Ended | |
|---|-------------------------|---------------|
| | June 30, | |
| | 2006 | 2005 |
| | (in millions) | |
| Cash and Cash Equivalents at Beginning of Period | \$ 401 | \$ 320 |
| Net Cash Flows From Operating Activities | 1,137 | 982 |
| Net Cash Flows From (Used For) Investing Activities | (1,586) | 458 |
| Net Cash Flows From (Used For) Financing Activities | 297 | (1,153) |
| Net Increase (Decrease) in Cash and Cash Equivalents | (152) | 287 |
| Cash and Cash Equivalents at End of Period | \$ 249 | \$ 607 |

Cash from operations, combined with a bank-sponsored receivables purchase agreement and short-term borrowings, provides working capital and allows us to 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 other subsidiaries that are not participants in either money pool for regulatory or operational reasons. As of June 30, 2006, we had credit facilities totaling \$3.0 billion to support our commercial paper program with \$144 million outstanding.

The maximum amount of commercial paper outstanding during the six months ended June 30, 2006 was \$325 million. The weighted-average interest rate for our commercial paper during the first six months of 2006 was 4.86%. We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding mechanisms are arranged. Sources of long-term funding include issuance of common stock or long-term debt and sale-leaseback or leasing agreements. Utility Money Pool borrowings and external borrowings may not exceed authorized limits under regulatory orders. See the discussion below for further detail related to the components of our cash flows.

Operating Activities

| | Six Months Ended June 30, | |
|---|--------------------------------------|---------------|
| | 2006 | 2005 |
| | (in millions) | |
| Net Income | \$ 556 | \$ 576 |
| Less: Income From Discontinued Operations | (6) | (4) |
| Income From Continuing Operations | 550 | 572 |
| Noncash Items Included in Earnings | 634 | 611 |
| Changes in Assets and Liabilities | (47) | (201) |
| Net Cash Flows From Operating Activities | \$ 1,137 | \$ 982 |

The key driver of the increase in cash from operations for the first six months of 2006 was due to no Pension Contributions to Qualified Plan Trusts in 2006 compared with a \$204 million contribution in 2005.

Net Cash Flows From Operating Activities were \$1.1 billion in 2006 consisting primarily of Income from Continuing Operations of \$550 million adjusted for noncash charges of \$634 million, which principally includes \$689 million for Depreciation and Amortization. In 2005, we initiated fuel proceedings in Oklahoma, Texas, Virginia and Arkansas seeking recovery of our increased fuel costs. Under-recovered fuel costs decreased in 2006 due to the recovery of higher cost of fuel, especially natural gas. 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 \$185 million cash increase from net Accounts Receivable/Accounts Payable due to a lower balance of Customer Accounts Receivable at June 30, 2006 and a \$189 million decrease in cash related to customer deposits held for trading activities.

Net Cash Flows From Operating Activities were \$982 million in 2005 consisting primarily of Income from Continuing Operations of \$572 million adjusted for noncash charges of \$611 million, which principally includes \$652 million for Depreciation and Amortization. We realized gains of \$115 million on sales of assets and made contributions of \$204 million to our pension trust fund. Changes in Assets and Liabilities represent those 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 \$155 million cash increase from Accounts Receivable, Net and an increase in the balance of Accrued Taxes of \$172 million. Cash increased related to Accounts Receivable, Net due to a higher factored balance at June 30, 2005. Accrued Taxes increased due to no estimated federal income tax payment during the first quarter of 2005 and paying \$43 million, net of refunds received, during the first half of 2005.

Investing Activities

**Six Months Ended
June 30,**

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| | 2006 | 2005 |
|--|-------------------|---------------|
| | (in millions) | |
| Investment Securities: | | |
| Purchases of Investment Securities | \$ (5,647) | \$ (2,141) |
| Sales of Investment Securities | 5,596 | 2,213 |
| Change in Investment Securities, Net | (51) | 72 |
| Construction Expenditures | (1,625) | (1,020) |
| Change in Other Temporary Cash Investments, Net | 3 | (103) |
| Proceeds from Sales of Assets | 123 | 1,500 |
| Other | (36) | 9 |
| Net Cash Flows From (Used for) Investing Activities | \$ (1,586) | \$ 458 |

Net Cash Flows Used For Investing Activities were \$1.6 billion in 2006 primarily due to Construction Expenditures, which increased mostly due to our environmental investment plan.

During 2006, we purchased \$5.6 billion of investments and received \$5.6 billion of proceeds from the sales of securities. During 2005, we purchased \$2.1 billion of investments and received \$2.2 billion of proceeds from the sales of securities. In our normal course of business, we purchase auction rate securities and variable rate demand notes with cash available for short-term investments. These amounts also include purchases and sales within our nuclear trusts.

Net Cash Flows From Investing Activities were \$458 million in 2005 primarily due to the proceeds from the sale of HPL, a portion of which we used to repurchase common stock and retire senior unsecured notes. Our Construction Expenditures of \$1 billion included generation, environmental, transmission and distribution investment.

We forecast \$2.1 billion of Construction Expenditures for the remainder of 2006, which will be funded through results of operations and financing activities. These expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, and the ability to access capital.

Financing Activities

| | Six Months Ended | |
|--|------------------|-------------------|
| | June 30, | |
| | 2006 | 2005 |
| | (in millions) | |
| Issuance of Common Stock | \$ 6 | \$ 28 |
| Repurchase of Common Stock | - | (427) |
| Issuance/Retirement of Debt, Net | 552 | (389) |
| Dividends Paid on Common Stock | (291) | (273) |
| Other | 30 | (92) |
| Net Cash Flows From (Used for) Financing Activities | \$ 297 | \$ (1,153) |

Net Cash Flows From Financing Activities in 2006 were \$297 million. During the six months of 2006, we issued \$115 million of new obligations relating to pollution control bonds, issued \$850 million of notes and retired \$396 million of notes for a net increase in notes outstanding of \$454 million and increased our short-term commercial paper outstanding by \$144 million. See Note 13 for a complete discussion of long-term debt issuances and retirements. The Other amount of \$30 million in the above table includes a \$68 million payment received from a coal supplier, net of an \$8 million repayment, related to a long-term coal purchase contract amended in March 2006.

Net Cash Flows Used For Financing Activities in 2005 were \$1.2 billion. During the six months of 2005, we repurchased common stock using a portion of the proceeds from the sale of HPL. In addition, our subsidiaries retired \$66 million of cumulative preferred stock, which is reflected in the Other amount in the above table.

Off-balance Sheet Arrangements

Under a limited set of circumstances we enter into off-balance sheet arrangements to accelerate cash collections, reduce operational expenses and spread risk of loss to third parties. Our current guidelines restrict the use of off-balance sheet financing entities or structures to traditional operating lease arrangements and sales of customer accounts receivable that we enter in the normal course of business. Our significant off-balance sheet arrangements have changed from year-end as follows:

| | June 30, 2006 | December 31, 2005 |
|-----------------------|--------------------------|------------------------------|
| | (in millions) | |
| AEP Credit | \$ 560 | \$ 516 |
| Rockport Plant Unit 2 | 2,437 | 2,511 |
| Railcars | 31 | 31 |

For complete information on each of these off-balance sheet arrangements see the “Off-balance Sheet Arrangements” section of “Management’s Financial Discussion and Analysis of Results of Operations” in the 2005 Annual Report.

Summary Obligation Information

A summary of our contractual obligations is included in our 2005 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in “Cash Flow” - “Financing Activities” above.

Other

Cook Plant Outage

On July 30, 2006, Unit 1 of our Cook Plant was taken off line due to elevated ambient temperatures in the containment building caused by a combination of high Lake Michigan water temperatures and partial blockage of cooling ventilation units. The Unit’s operating license limits the containment building temperature to 120 degrees. Supplemental cooling units were installed on both units and will remain in place for the near future. Unit 1 returned to service on August 3, 2006.

Texas REPs

As part of the purchase and sale agreement related to the sale of our Texas REPs in 2002, we retained the right to share in earnings with Centrica from the two REPs above a threshold amount through 2006 if the Texas retail market developed increased earnings opportunities. In March of 2006, we received a \$70 million payment for our share in earnings for 2005. The payment for 2006 is contingent on Centrica’s future operating results, capped at \$20 million and, to the extent earned, is expected to be received in the first quarter of 2007. See “Texas REPs” section of Note 8.

New Generation

In December 2005, PSO sought proposals for new base load generation to be online in 2011. PSO received six proposals and evaluated those proposals meeting the Request for Proposal criteria with oversight from a neutral third party. In July 2006, PSO announced plans to enter a joint venture with Oklahoma Gas and Electric Company (OG&E)

where OG&E will construct and operate a new 950 MW coal-fueled electricity generating unit near Red Rock, Oklahoma. PSO will own 50% of the new unit. Preliminary cost estimates for 100% of the new facility are approximately \$1.8 billion. The 2006 through 2008 estimated construction expenditures as disclosed in our 2005 Form 10-K included cost estimates for a base load facility.

In December 2005, SWEPCo sought proposals for new peaking, intermediate and base load generation to be online between 2008 and 2011. In May 2006, SWEPCo announced plans to construct short-term, mid-term and long-term generation to meet the demands of its customers. SWEPCo will build up to 480 MW of simple-cycle natural gas combustion turbine peaking generation in Tontitown, Arkansas and will build a 480 MW combined-cycle natural gas fired plant at the existing Arsenal Hill Power Plant in Shreveport, Louisiana. SWEPCo also plans to build a new base load coal or lignite-fueled plant by 2011 to meet the longer-term generation needs of its customers. Preliminary cost estimates for the new facilities are approximately \$1.4 billion. The 2006 through 2008 estimated construction expenditures as disclosed in our 2005 Form 10-K included cost estimates for these types of facilities.

All new generation construction projects discussed above are subject to regulatory approvals from the various states in which the companies operate. Construction is expected to begin in 2007.

SIGNIFICANT FACTORS

We continue to be involved in various matters described in the “Significant Factors” section of Management’s Financial Discussion and Analysis of Results of Operations in our 2005 Annual Report. The 2005 Annual Report should be read in conjunction with this report in order to understand significant factors without material changes in status since the issuance of our 2005 Annual Report, but may have a material impact on our future results of operations, cash flows and financial condition.

AEP Interstate Project

In January 2006, we filed a proposal with the FERC and PJM to build a new 765 kV 550-mile transmission line stretching from West Virginia to New Jersey. The 765 kV line is designed to create a major thoroughfare and reduce PJM congestion costs by substantially improving west-east peak transfer capability by approximately 5,000 MW and reducing transmission line losses by up to 280 MW. It will also enhance reliability of the Eastern transmission grid. A new subsidiary, AEP Transmission Co., LLC, will own the line and undertake construction of the project. The projected cost for the project is approximately \$3 billion, which may be shared with other participants, and the project is subject to PJM, state and federal regulatory approvals and appropriate incentive cost recovery mechanisms. The projected in-service date is 2014, subject to PJM and FERC approvals, assuming three years to site and acquire rights-of-way and five years to construct the line. We also were the first to file with the DOE seeking to have the proposed route designated a National Interest Electric Transmission Corridor (NIETC). The Energy Policy Act of 2005 provides for NIETC designation for areas experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers.

In July 2006, the FERC granted conditional approval for incentive rate treatment for the proposed line as we requested. The approval is conditioned upon the new line being included in PJM’s formal Regional Transmission Expansion Plan to be finalized later this year or in early 2007. The approved incentives include, (a) a return on equity set at the high end of the “zone of reasonableness”; (b) the option to timely recover the cost of capital associated with construction work in progress; and (c) the ability to defer expense and recover costs incurred during the pre-construction and pre-operating period. The approval does not constitute final FERC action, as we will need to implement the incentives in future rate filings.

Texas Regulatory Activity

Texas Restructuring

The PUCT issued an order in TCC's True-up Proceeding in February 2006, which determined that TCC's true-up regulatory asset was \$1.475 billion including carrying costs through September 2005. In December 2005, TCC adjusted its recorded net true-up regulatory asset to comply with the order. We appealed, seeking additional recovery consistent with the Texas Restructuring Legislation and related rules. Other parties have appealed the PUCT's order claiming it permits TCC to over-recover stranded costs.

TCC filed an application in March 2006 requesting to securitize its net stranded generation plant costs and related carrying costs through August 31, 2006. In June 2006, the PUCT approved TCC's settlement with intervenors authorizing the securitization of \$1.697 billion of net stranded generation costs including carrying costs through August 31, 2006, the assumed securitization date, plus estimated issuance costs of \$23 million, for a total of \$1.72 billion. We anticipate issuing the securitization bonds by the end of the third quarter of 2006.

The differences between the securitization amount ordered by the PUCT of \$1.7 billion and the recorded securitizable true-up regulatory asset of \$1.5 billion at June 30, 2006 are detailed in the table below:

| | (in millions) |
|---|-----------------|
| Stranded Generation Plant Costs | \$ 974 |
| Net Generation-related Regulatory Asset | 249 |
| Excess Earnings | (49) |
| Recorded Net Stranded Generation Plant Costs | 1,174 |
| Recorded Debt Carrying Costs on Net Stranded Generation Plant Costs | 375 |
| Recorded Securitizable True-up Regulatory Asset | 1,549 |
| Unrecorded But Recoverable Equity Carrying Costs | 217 |
| Unrecorded Estimated July 2006 - August 2006 Debt Carrying Costs | 17 |
| Unrecorded Excess Earnings, Related Carrying Costs and Other | 52 |
| Settlement Reduction | (77) |
| Reduction for ADITC and EDFIT Benefits | (61) |
| Approved Securitizable Amount | 1,697 |
| Unrecorded Securitization Issuance Costs | 23 |
| Amount to be Securitized | \$ 1,720 |

In June 2006, TCC filed to implement a CTC refund of \$355 million for its net other true-up items over eight years. The differences between the components of TCC's Recorded Net Regulatory Liabilities for Other True-up Items as of June 30, 2006 and its CTC proceeding request are detailed below:

| | (in millions) |
|--|---------------|
| Wholesale Capacity Auction True-up | \$ 61 |
| Carrying Costs on Wholesale Capacity Auction True-up | 28 |
| Retail Clawback including Carrying Costs | (63) |
| Deferred Over-recovered Fuel Balance | (181) |
| Retrospective ADFIT Benefit | (70) |
| Other | (4) |
| Recorded Net Regulatory Liabilities - Other True-up Items | (229) |
| Unrecorded Prospective ADFIT Benefit | (240) |
| Unrecorded Estimated July 2006 - August 2006 Carrying Costs | (6) |
| Gross CTC Refund | (475) |
| FERC Jurisdictional Fuel Refund Deferral | 16 |
| ADITC and EDFIT Benefit Refund Deferral | 97 |
| Net CTC Refund Proposed, After Deferrals | (362) |
| Rate Case Expense Surcharge | 7 |

| | |
|--|-----------------|
| Net Refund Proposed, After Deferrals and Expenses | \$ (355) |
|--|-----------------|

TCC requested that a portion of the refund be deferred, pending the outcome of two contingent federal matters related to the refund of \$16 million of FERC jurisdictional fuel over-recoveries and \$97 million for potential tax normalization violation matters related to the refund of ADITC and EDFIT benefits. Although TCC proposed to refund the \$355 million over eight years, certain intervenors have supported accelerated refunds. Management cannot predict the outcome of this filing. If the two contingent federal matters are resolved unfavorably, TCC will refund the \$16 million and the \$97 million plus carrying costs.

Municipal customers and other intervenors are appealing the PUCT orders seeking to further reduce TCC's true-up recoveries. If we determine as a result of future PUCT orders or appeal court rulings that it is probable TCC cannot recover a portion of its recorded net true-up regulatory asset and we are able to estimate the amount of a resultant impairment, we would record a provision for such amount which would have an adverse effect on future results of operations, cash flows and possibly financial condition. TCC is appealing the PUCT orders seeking relief in both state and federal court where it believes the PUCT's rulings are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law.

These appeals could take years to resolve and could result in material effects on future results of operations. If the PUCT rejects TCC's deferral proposal and a normalization violation occurs, future results of operations and cash flows could be adversely affected by the recapture of \$105 million of TCC's ADITC and the loss by TCC of future accelerated tax depreciation election. The estimated future impact on earnings of the Texas restructuring as of June 30, 2006, exclusive of a possible normalization violation and any effects of appeal litigation, over the 14-year securitization net recovery period assuming the PUCT approves TCC's CTC filing is detailed below:

| | (in millions) |
|--|----------------------|
| ADITC and EDFIT Benefits Reducing Securitization | \$ 97 |
| ADFIT Benefit Applied to Reduce 2002 Securitization of Regulatory Assets | (64) |
| Securitization Settlement | (77) |
| Unrecorded Prospective ADFIT Benefit Increasing the CTC Refund | (240) |
| Unrecorded Equity Carrying Costs Recognized as Collected | 217 |
| Future Carrying Cost Payable on Proposed CTC Refund | (113) |
| Deferred Fuel - Federal Jurisdictional Issue | 16 |
| Net Adverse Earnings Impact Over 14 Years | \$ (164) |

If the proposed CTC deferral is rejected by the PUCT or the two contingencies are refunded to customers, the future adverse impact on results of operations over the next 14 years will increase to \$317 million. This potential adverse impact on results of operations over the next 14 years would be more than offset by the annual cost of money benefit from the \$2.2 billion in net proceeds that resulted from the sale of bonds in connection with the initial regulatory asset securitization in 2002 of \$797 million and from the upcoming \$1.720 billion sale of securitization bonds later this year less the proposed \$355 million CTC refund over the next eight years.

Litigation

In the ordinary course of business, we and our subsidiaries are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases that have a probable likelihood of loss and the loss amount can be estimated. For details on our pending litigation and regulatory proceedings see Note 4 - Rate Matters, Note 6 - Customer Choice and Industry Restructuring, Note 7 - Commitments and Contingencies and the "Litigation" section of "Management's Financial Discussion and Analysis of

Results of Operations” in the 2005 Annual Report. Additionally, see Note 3 - Rate Matters, Note 4 - Customer Choice and Industry Restructuring and Note 5 - Commitments and Contingencies included herein. An adverse result in these proceedings has the potential to materially affect the results of operations, cash flows and financial condition of AEP and its subsidiaries.

See discussion of the Environmental Litigation within the “Environmental Matters” section of “Significant Factors.”

Environmental Matters

We have committed to substantial capital investments and additional operational costs to comply with new environmental control requirements. The sources of these requirements include:

- Requirements under the CAA to reduce emissions of SO₂, NO_x, particulate matter (PM), and mercury from fossil fuel-fired power plants;
- Requirements under the Clean Water Act (CWA) 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 (CO₂) emissions to address concerns about global climate change.

In addition, we are engaged in litigation with respect to certain environmental matters, have been notified of potential responsibility for the clean-up of contaminated sites, and incur costs for disposal of spent nuclear fuel and future decommissioning of our nuclear units. All of these matters are discussed in the “Environmental Matters” section of “Management’s Financial Discussion and Analysis of Results of Operations” in the 2005 Annual Report.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation’s air quality and control mobile and stationary sources of air emissions. The major CAA programs affecting our power plants are briefly described below. Many of these programs are implemented and administered by the states, which can impose additional or more stringent requirements.

National Ambient Air Quality Standards: The CAA requires the Federal EPA to periodically review the available scientific data for six criteria pollutants and establish a concentration level in the ambient air for those substances that is adequate to protect the public health and welfare with an extra margin for safety. These concentration levels are known as national ambient air quality standards (NAAQS).

Each state identifies those areas within its boundaries that meet the NAAQS (attainment areas) and those that do not (nonattainment areas). Each state must then develop a state implementation plan (SIP) to bring nonattainment areas into compliance with the NAAQS and maintain good air quality in attainment areas. All SIPs are then submitted to the Federal EPA for approval. If a state fails to develop adequate plans, the Federal EPA must develop and implement a plan. In addition, as the Federal EPA reviews the NAAQS, the attainment status of areas can change, and states may be required to develop new SIPs. The Federal EPA recently proposed a new PM NAAQS and is conducting periodic reviews for additional criteria pollutants.

In 1997, the Federal EPA established new NAAQS that required further reductions in SO₂ and NO_x emissions. In 2005, the Federal EPA issued a final model federal rule, the Clean Air Interstate Rule (CAIR), that assists states developing new SIPs to meet the new NAAQS. CAIR reduces regional emissions of SO₂ and NO_x from power plants in the Eastern U.S. (29 states and the District of Columbia). CAIR requires power plants within these states to reduce emissions of SO₂ by 50 percent by 2010, and by 65 percent by 2015. NO_x emissions will be subject to additional limits beginning in 2009, and will be reduced by a total of 70 percent from current levels by 2015. Reduction of both SO₂ and NO_x would be achieved through a cap-and-trade program. The Federal EPA affirmed certain aspects of the

final CAIR after considering petitions for reconsideration. The rule has been challenged in the courts. States must develop and submit SIPs to implement CAIR by November 2006. Nearly all of the states in which our power plants are located will be covered by CAIR. Oklahoma is not affected, while Texas and Arkansas will be covered only by certain parts of CAIR. A SIP that complies with CAIR will also establish compliance with other CAA requirements, including certain visibility goals.

Hazardous Air Pollutants: As a result of the 1990 Amendments to the CAA, the Federal EPA investigated hazardous air pollutant (HAP) emissions from the electric utility sector and submitted a report to Congress, identifying mercury emissions from coal-fired power plants as warranting further study. In March 2005, the Federal EPA issued a final Clean Air Mercury Rule (CAMR) setting mercury standards for new coal-fired power plants and requiring all states to issue new SIPs including mercury requirements for existing coal-fired power plants. The Federal EPA issued a model federal rule based on a cap-and-trade program for mercury emissions from existing coal-fired power plants that would reduce mercury emissions to 38 tons per year from all existing plants in 2010, and to 15 tons per year in 2018. The national cap of 38 tons per year in 2010 is intended to reflect the level of reduction in mercury emissions that will be achieved as a result of installing controls to reduce SO₂ and NO_x emissions in order to comply with CAIR. The Federal EPA reaffirmed the final CAMR after reconsidering certain aspects of the rule, and the rule has been challenged in the courts. States must develop and submit their SIPs to implement CAMR by November 2006.

The Acid Rain Program: The 1990 Amendments to the CAA included a cap-and-trade emission reduction program for SO₂ emissions from power plants, implemented in two phases. By 2000, the program established a nationwide cap on power plant SO₂ emissions of 8.9 million tons per year. The 1990 Amendments also contained requirements for power plants to reduce NO_x emissions through the use of available combustion controls.

The success of the SO₂ cap-and-trade program encouraged the Federal EPA and the states to use it as a model for other emission reduction programs, including CAIR and CAMR. We meet our obligations under the Acid Rain Program through the installation of controls, use of alternate fuels, and participation in the emissions allowance markets. CAIR uses the SO₂ allowances originally allocated through the Acid Rain Program as the basis for its SO₂ cap-and-trade system.

Regional Haze: The CAA also establishes visibility goals for certain federally-designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing impairment and remedying any existing impairment of visibility in these areas. This is commonly called the "Regional Haze" program. In June 2005, the Federal EPA issued its final Clean Air Visibility Rule (CAVR), detailing how the CAA's best available retrofit technology (BART) requirements will be applied to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. The final rule contains a demonstration that for power plants subject to CAIR, CAIR will result in more visibility improvements than BART would provide. Thus, states are allowed to substitute CAIR requirements in their Regional Haze SIPs for controls that would otherwise be required by BART. For BART-eligible facilities located in states not subject to CAIR requirements for SO₂ and NO_x, some additional controls will be required. The final rule has been challenged in the courts.

Estimated Air Quality Environmental Investments

As discussed in the 2005 Annual Report, the CAIR and CAMR programs described above will require us to make significant additional investments, some of which are estimable. However, many of the rules described above have been challenged in the courts and have not yet been incorporated into SIPs. As a result, these rules may be further modified. Our 2006 through 2010 investment estimates of \$191 million for NO_x controls and \$2.8 billion for SO₂ controls disclosed in the 2005 Annual Report are subject to significant uncertainties, and will be affected by any changes in the outcome of several interrelated variables and assumptions, including: the timing of implementation, required levels of reductions, methods for allocation of allowances and our selected compliance alternatives. In short, we cannot estimate our compliance costs with certainty.

We will seek recovery of expenditures for pollution control technologies, replacement or additional generation and associated operating costs from customers through our regulated rates (in regulated jurisdictions). We should be able to recover these expenditures through market prices in deregulated jurisdictions. If not, those costs could adversely affect future results of operations, cash flows and possibly financial condition.

Potential Regulation of CO₂ Emissions

At the Third Conference of the Parties to the United Nations Framework Convention on Climate Change held in Kyoto, Japan in December 1997, more than 160 countries, including the U.S., negotiated a treaty requiring legally-binding reductions in emissions of greenhouse gases, chiefly CO₂, which many scientists believe are contributing to global climate change. The U.S. signed the Kyoto Protocol in November 1998, but the treaty was not submitted to the Senate for its advice and consent. In March 2001, President Bush announced his opposition to the treaty. During 2004, enough countries ratified the treaty for it to become enforceable against the ratifying countries in February 2005. Several bills have been introduced in Congress seeking regulation of greenhouse gas emissions, including CO₂ emissions from power plants, but none have passed either house of Congress.

The Federal EPA stated that it does not have authority under the CAA to regulate greenhouse gas emissions that may affect global climate trends. This decision was challenged in the courts and upheld by an appellate court. The U.S. Supreme Court will review the appellate decision. While mandatory requirements to reduce CO₂ emissions at our power plants do not appear imminent, we participate in a number of voluntary programs to monitor, mitigate, and reduce greenhouse gas emissions.

Environmental Litigation

New Source Review (NSR) Litigation: In 1999, the Federal EPA and a number of states filed complaints alleging that APCo, CSPCo, I&M, and OPCo modified certain units at coal-fired generating plants in violation of the NSR requirements of the CAA. A separate lawsuit, initiated by certain environmental intervenor groups, has been consolidated with the Federal EPA case. Several similar complaints were filed in 1999 and 2000 against other nonaffiliated utilities, including Allegheny Energy, Eastern Kentucky Electric Cooperative, Public Service Enterprise Group, Santee Cooper, Wisconsin Electric Power Company, Mirant, NRG Energy and Niagara Mohawk. Several of these cases were resolved through consent decrees. The alleged modifications at our power plants occurred over a 20-year period. A bench trial on the liability issues was held during July 2005. Briefing has concluded. In June 2006, the judge stayed the liability decision pending the issuance of a decision by the U.S. Supreme Court in the Duke Energy case. A bench trial on remedy issues, if necessary, is scheduled to begin four months after the U.S. Supreme Court decision is issued.

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.

Courts that considered whether the activities at issue in these cases are routine maintenance, repair, or replacement, and therefore are excluded from NSR, reached different conclusions. Similarly, courts that considered whether the activities at issue increased emissions from the power plants reached different results. Appeals on these and other issues were filed in certain appellate courts, including a petition to appeal to the U.S. Supreme Court that was granted in one case. The Federal EPA issued a final rule that would exclude activities similar to those challenged in these cases from NSR as “routine replacements.” In March 2006, the Court of Appeals for the District of Columbia Circuit issued a decision vacating the rule. The Federal EPA filed a petition for rehearing in that case, which the Court denied. The Federal EPA also recently proposed a rule that would define “emissions increases” in a way that would exclude most of the challenged activities from NSR.

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, we believe we can recover any capital and operating costs of additional pollution control equipment that may be required through regulated rates and market prices for electricity. If we are unable to recover such costs or if material penalties are imposed, it would adversely affect future results of operations, cash flows and possibly financial condition.

Other Environmental Concerns

We perform environmental reviews and audits on a regular basis for the purpose of identifying, evaluating and addressing environmental concerns and issues. In addition to the matters discussed above, we manage other environmental concerns that we do not believe are material or potentially material at this time. If they become significant or if any new matters arise that we believe could be material, they could have a material adverse effect on future results of operations, cash flows and possibly financial condition.

Critical Accounting Estimates

See the “Critical Accounting Estimates” section of “Management’s Financial Discussion and Analysis of Results of Operations” in the 2005 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.

Adoption of New Accounting Pronouncements

Beginning in 2006, we adopted SFAS No. 123 (revised 2004) Share-Based Payment, on a modified prospective basis, resulting in an insignificant favorable cumulative effect of a change in accounting principle. Including stock-based compensation expense related to employee stock options and other share based awards, did not materially affect our quarter-over-quarter and year-to-date net income and earnings per share. As of June 30, 2006, we have \$43 million of total unrecognized compensation cost related to unvested share-based compensation arrangements. Our unrecognized compensation cost will be recognized over a weighted-average period of 1.63 years. See Note 2 - New Accounting Pronouncements in our Condensed Notes to Condensed Consolidated Financial Statements for further discussion.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

As a major power producer and marketer of wholesale electricity, coal and emission allowances, our Utility Operations segment is exposed to certain market risks. These risks include commodity price risk, interest rate risk and credit risk. In addition, we may be exposed to foreign currency exchange risk because occasionally we procure various services and materials in our energy business from foreign suppliers. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

Our Investment - Gas Operations segment holds forward gas contracts that were not sold with the gas pipeline and storage assets. These contracts are primarily financial derivatives, along with physical contracts, which will gradually liquidate and completely expire in 2011. Our risk objective is to keep these positions generally risk neutral through maturity.

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, coal, and emissions and to a lesser degree other commodities associated with our energy business. As a result, we are subject to price risk. The amount of risk taken is controlled by risk management operations, our Chief Risk Officer and risk management staff. When risk management activities exceed certain predetermined limits, the positions are modified to reduce the risk to be within the limits unless specifically approved by the Risk Executive Committee.

We have 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 various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. Our committee meets monthly and consists of the Chief Risk Officer, senior executives, and other 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 applicable to our business activities. The following tables provide information on our risk management activities.

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

The following two tables summarize the various mark-to-market (MTM) positions included in our condensed balance sheet as of June 30, 2006 and the reasons for changes in our total MTM value included in our condensed balance sheet as compared to December 31, 2005.

**Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheet
June 30, 2006
(in millions)**

Total

| | Utility Operations | Investments - Gas Operations | Sub-Total MTM Risk Management Contracts | PLUS: MTM of Cash Flow and Fair Value Hedges | |
|--|-----------------------|------------------------------------|--|---|---------------|
| Current Assets | \$ 431 | \$ 123 | \$ 554 | \$ 65 | \$ 619 |
| Noncurrent Assets | 390 | 175 | 565 | 12 | 577 |
| Total Assets | 821 | 298 | 1,119 | 77 | 1,196 |
| Current Liabilities | (338) | (126) | (464) | (16) | (480) |
| Noncurrent Liabilities | (235) | (181) | (416) | (2) | (418) |
| Total Liabilities | (573) | (307) | (880) | (18) | (898) |
| Total MTM Derivative Contract Net | | | | | |
| Assets (Liabilities) | \$ 248 | \$ (9) | \$ 239 | \$ 59 | \$ 298 |

MTM Risk Management Contract Net Assets (Liabilities)
Six Months Ended June 30, 2006
(in millions)

| | Utility Operations | Investments-Gas Operations | Total |
|---|-----------------------|-------------------------------|---------------|
| Total MTM Risk Management Contract Net Assets (Liabilities) at | | | |
| December 31, 2005 | \$ 215 | \$ (19) | \$ 196 |
| (Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period | (8) | 8 | - |
| Fair Value of New Contracts at Inception When Entered During the Period (a) | 1 | - | 1 |
| Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During The Period | 13 | - | 13 |
| Changes in Fair Value Due to Valuation Methodology Changes on Forward Contracts | 1 | - | 1 |
| Changes in Fair Value due to Market Fluctuations During the Period (b) | 13 | 2 | 15 |
| Changes in Fair Value Allocated to Regulated Jurisdictions (c) | 13 | - | 13 |
| Total MTM Risk Management Contract Net Assets (Liabilities) at | | | |
| June 30, 2006 | \$ 248 | \$ (9) | \$ 239 |
| Net Cash Flow and Fair Value Hedge Contracts | | | 59 |
| Ending Net Risk Management Assets at June 30, 2006 | | | \$ 298 |

- (a) 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.
- (b) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.

- (c) "Change in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Operations. These net gains (losses) are recorded as regulatory assets/liabilities for those subsidiaries that operate in regulated jurisdictions. Approximately \$7 million of the regulatory deferral change is due to the change in the SIA. See the "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 3.

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

The following table presents:

- The method of measuring fair value used in determining the carrying amount of our total MTM asset or liability (external sources or modeled internally).
- The maturity, by year, of our net assets/liabilities, 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 June 30, 2006
(in millions)**

| | Remainder 2006 | 2007 | 2008 | 2009 | 2010 | After 2010 | Total |
|---|-------------------|--------------|--------------|--------------|--------------|---------------|------------|
| Utility Operations: | | | | | | | |
| Prices Actively Quoted - Exchange Traded Contracts | \$ (11) | \$ 1 | \$ 14 | \$ - | \$ - | \$ - | 4 |
| Prices Provided by Other External Sources - OTC Broker Quotes (a) | 43 | 68 | 33 | 25 | - | - | 169 |
| Prices Based on Models and Other Valuation Methods (b) | 20 | (1) | 6 | 13 | 28 | 9 | 75 |
| Total | \$ 52 | \$ 68 | \$ 53 | \$ 38 | \$ 28 | \$ 9 | 248 |
| Investments - Gas Operations: | | | | | | | |
| Prices Actively Quoted - Exchange Traded Contracts | \$ (1) | \$ 11 | \$ - | \$ - | \$ - | \$ - | 10 |
| Prices Provided by Other External Sources - OTC Broker Quotes (a) | (3) | (8) | - | - | - | - | (11) |
| Prices Based on Models and Other Valuation Methods (b) | (1) | - | (1) | (4) | (3) | 1 | (8) |
| Total | \$ (5) | \$ 3 | (1) | (4) | (3) | 1 | (9) |
| Total: | | | | | | | |
| Prices Actively Quoted - Exchange Traded Contracts | \$ (12) | \$ 12 | \$ 14 | \$ - | \$ - | \$ - | 14 |
| Prices Provided by Other External Sources - OTC Broker Quotes (a) | 40 | 60 | 33 | 25 | - | - | 158 |
| Prices Based on Models and Other Valuation Methods (b) | 19 | (1) | 5 | 9 | 25 | 10 | 67 |
| Total | \$ 47 | \$ 71 | \$ 52 | \$ 34 | \$ 25 | \$ 10 | 239 |

(a)

Prices Provided by Other External Sources - OTC Broker Quotes reflects information obtained from over-the-counter (OTC) brokers, industry services, or multiple-party on-line platforms.

- (b) Prices Based on Models and Other Valuation Methods is 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.

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

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 June 30, 2006**

| Commodity | Transaction Class | Market/Region | Tenor (in Months) |
|------------------|---------------------------------|---|------------------------------|
| Natural Gas | Futures | NYMEX / Henry Hub | 60 |
| | Physical Forwards | Gulf Coast, Texas | 21 |
| | Swaps | Northeast, Mid-Continent, Gulf Coast, Texas | 21 |
| | Exchange Option Volatility | NYMEX / Henry Hub | 12 |
| Power | Futures | AEP East - PJM | 36 |
| | Physical Forwards | AEP East | 42 |
| | Physical Forwards | AEP West | 42 |
| | Physical Forwards | West Coast | 42 |
| | Peak Power Volatility (Options) | AEP East - Cinergy, PJM | 12 |
| Emissions | Credits | SO ₂ , NO _x | 30 |
| Coal | Physical Forwards | PRB, NYMEX, CSX | 30 |

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

We are exposed to market fluctuations in energy commodity prices impacting our power and remaining 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 derivative transactions to manage interest rate risk related to existing variable rate debt and to manage interest rate exposure on anticipated borrowings of fixed-rate debt. We do not hedge all interest rate exposure.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Condensed Consolidated Balance Sheets and the reasons for changes in cash flow hedges from December 31, 2005 to June 30, 2006. The following table also indicates what portion of designated, effective hedges are expected to be reclassified into net income in the next 12 months. Only contracts designated as effective cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and are included in the previous risk management tables.

**Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Six Months Ended June 30, 2006
(in millions)**

| | Power and Gas | Interest Rate | Total |
|--|------------------|------------------|---------|
| Beginning Balance in AOCI, December 31, 2005 | \$ (6) | \$ (21) | \$ (27) |
| Changes in Fair Value | 37 | 12 | 49 |
| Reclassifications from AOCI to Net Income for Cash Flow | | | |
| Hedges Settled | 3 | 2 | 5 |
| Ending Balance in AOCI, June 30, 2006 | \$ 34 | \$ (7) | \$ 27 |
| After-Tax Portion Expected to be Reclassified to Earnings During Next 12 Months | \$ 30 | \$ (1) | \$ 29 |

Credit Risk

We limit credit risk in our marketing and trading activities 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 Investors Service, Standard & Poor's and qualitative and quantitative data to assess the financial health of counterparties on an ongoing basis. We use our analysis, in conjunction with the rating agencies' information, 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. As of June 30, 2006, our credit exposure net of credit collateral to sub investment grade counterparties was approximately 5.90%, expressed in terms of net MTM assets and net receivables. As of June 30, 2006, 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 | \$ 883 | \$ 156 | \$ 727 | 1 | \$ 107 |
| Split Rating | 2 | - | 2 | 2 | 2 |
| Noninvestment Grade | 109 | 106 | 3 | 1 | 3 |
| No External Ratings: | | | | | |
| Internal Investment Grade | 28 | - | 28 | 1 | 10 |
| Internal Noninvestment Grade | 58 | 13 | 45 | 3 | 43 |
| Total as of June 30, 2006 | \$ 1,080 | \$ 275 | \$ 805 | 8 | \$ 165 |
| As of December 31, 2005 | \$ 1,366 | \$ 484 | \$ 882 | 10 | 322 |

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, 2008. 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, taking into consideration scheduled plant outages, for which we have sales commitments or estimated requirement obligations to customers.

Generation Plant Hedging Information Estimated Next Three Years As of June 30, 2006

| | Remainder | | |
|-------------------------------|-----------|------|------|
| | 2006 | 2007 | 2008 |
| Estimated Plant Output Hedged | 91% | 90% | 88% |

VaR Associated with Risk Management Contracts

Commodity Price Risk

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 June 30, 2006, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

VaR Model

| Six Months Ended June 30, 2006 (in millions) | | | | Twelve Months Ended December 31, 2005 (in millions) | | | |
|---|-------------|----------------|------------|--|-------------|----------------|------------|
| End | High | Average | Low | End | High | Average | Low |
| \$2 | \$7 | \$3 | \$1 | \$3 | \$5 | \$3 | \$1 |

Interest Rate Risk

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 \$690 million at June 30, 2006 and \$615 million at December 31, 2005. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not materially affect our results of operations, cash flows or financial position.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
For the Three and Six Months Ended June 30, 2006 and 2005
(in millions, except per-share amounts)
(Unaudited)

| | Three Months Ended | | Six Months Ended | |
|---|--------------------|--------------|------------------|--------------|
| | 2006 | 2005 | 2006 | 2005 |
| REVENUES | | | | |
| Utility Operations | \$ 2,810 | \$ 2,680 | \$ 5,797 | \$ 5,285 |
| Gas Operations | (15) | 19 | (33) | 376 |
| Other | 141 | 120 | 280 | 223 |
| TOTAL | 2,936 | 2,819 | 6,044 | 5,884 |
| EXPENSES | | | | |
| Fuel and Other Consumables Used for Electric Generation | 888 | 804 | 1,849 | 1,593 |
| Purchased Energy for Resale | 237 | 183 | 403 | 313 |
| Purchased Gas for Resale | - | 1 | - | 250 |
| Maintenance and Other Operation | 902 | 878 | 1,730 | 1,715 |
| Gain/Loss on Disposition of Assets, Net | - | - | (68) | (115) |
| Depreciation and Amortization | 348 | 325 | 689 | 652 |
| Taxes Other Than Income Taxes | 190 | 173 | 381 | 361 |
| TOTAL | 2,565 | 2,364 | 4,984 | 4,769 |
| OPERATING INCOME | 371 | 455 | 1,060 | 1,115 |
| Interest and Investment Income | 11 | 14 | 19 | 25 |
| Carrying Costs Income | 33 | 36 | 63 | 56 |
| Allowance For Equity Funds Used During Construction | 7 | 6 | 13 | 12 |
| Gain on Disposition of Equity Investments, Net | - | - | 3 | - |
| INTEREST AND OTHER CHARGES | | | | |
| Interest Expense | 176 | 188 | 344 | 361 |
| Preferred Stock Dividend Requirements of Subsidiaries | - | 3 | 1 | 5 |
| TOTAL | 176 | 191 | 345 | 366 |
| INCOME BEFORE INCOME TAX EXPENSE, MINORITY INTEREST EXPENSE AND EQUITY EARNINGS (LOSS) | | | | |
| | 246 | 320 | 813 | 842 |
| Income Tax Expense | 72 | 103 | 261 | 275 |
| Minority Interest Expense | 1 | 1 | 1 | 2 |
| Equity Earnings (Loss) of Unconsolidated Subsidiaries | (1) | 2 | (1) | 7 |

| | | | | | |
|--|---------|---------|---------|---------|-----|
| INCOME BEFORE DISCONTINUED OPERATIONS | | | | | |
| | 172 | | 218 | 550 | 572 |
| DISCONTINUED OPERATIONS, Net of Tax | | | | | |
| | 3 | | 3 | 6 | 4 |
| NET INCOME | \$ 175 | \$ 221 | \$ 556 | \$ 576 | |
| WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING | | | | | |
| | 394 | | 384 | 394 | 389 |
| BASIC EARNINGS PER SHARE | | | | | |
| Income Before Discontinued Operations | \$ 0.44 | \$ 0.57 | \$ 1.40 | \$ 1.47 | |
| Discontinued Operations, Net of Tax | - | 0.01 | 0.01 | 0.01 | |
| TOTAL BASIC EARNINGS PER SHARE | \$ 0.44 | \$ 0.58 | \$ 1.41 | \$ 1.48 | |
| WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING | | | | | |
| | 396 | | 385 | 396 | 390 |
| DILUTED EARNINGS PER SHARE | | | | | |
| Income Before Discontinued Operations | \$ 0.43 | \$ 0.57 | \$ 1.39 | \$ 1.47 | |
| Discontinued Operations, Net of Tax | 0.01 | 0.01 | 0.02 | 0.01 | |
| TOTAL DILUTED EARNINGS PER SHARE | \$ 0.44 | \$ 0.58 | \$ 1.41 | \$ 1.48 | |
| CASH DIVIDENDS PAID PER SHARE | | | | | |
| | \$ 0.37 | \$ 0.35 | \$ 0.74 | \$ 0.70 | |

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS

ASSETS

June 30, 2006 and December 31, 2005

(in millions)

(Unaudited)

| | 2006 | 2005 |
|---|------------------|------------------|
| CURRENT ASSETS | | |
| Cash and Cash Equivalents | \$ 249 | \$ 401 |
| Other Temporary Cash Investments | 173 | 127 |
| Accounts Receivable: | | |
| Customers | 659 | 826 |
| Accrued Unbilled Revenues | 347 | 374 |
| Miscellaneous | 45 | 51 |
| Allowance for Uncollectible Accounts | (34) | (31) |
| Total Receivables | 1,017 | 1,220 |
| Fuel, Materials and Supplies | 865 | 726 |
| Risk Management Assets | 619 | 926 |
| Margin Deposits | 154 | 221 |
| Regulatory Asset for Under-Recovered Fuel Costs | 74 | 197 |
| Other | 104 | 127 |
| TOTAL | 3,255 | 3,945 |
| PROPERTY, PLANT AND EQUIPMENT | | |
| Electric: | | |
| Production | 16,877 | 16,653 |
| Transmission | 6,915 | 6,433 |
| Distribution | 11,073 | 10,702 |
| Other (including coal mining and nuclear fuel) | 3,203 | 3,116 |
| Construction Work in Progress | 2,423 | 2,217 |
| Total | 40,491 | 39,121 |
| Accumulated Depreciation and Amortization | 15,093 | 14,837 |
| TOTAL - NET | 25,398 | 24,284 |
| OTHER NONCURRENT ASSETS | | |
| Regulatory Assets | 3,234 | 3,262 |
| Securitized Transition Assets and Other | 572 | 593 |
| Spent Nuclear Fuel and Decommissioning Trusts | 1,159 | 1,134 |
| Investments in Power and Distribution Projects | 45 | 97 |
| Goodwill | 76 | 76 |
| Long-term Risk Management Assets | 577 | 886 |
| Employee Benefits and Pension Assets | 1,075 | 1,105 |
| Other | 747 | 746 |
| TOTAL | 7,485 | 7,899 |
| Assets Held for Sale | 46 | 44 |
| TOTAL ASSETS | \$ 36,184 | \$ 36,172 |

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
June 30, 2006 and December 31, 2005
(Unaudited)

| | 2006 | 2005 |
|--|------------------|------------------|
| CURRENT LIABILITIES | | |
| | (in millions) | |
| Accounts Payable | \$ 1,191 | \$ 1,144 |
| Short-term Debt | 159 | 10 |
| Long-term Debt Due Within One Year | 800 | 1,153 |
| Risk Management Liabilities | 480 | 906 |
| Accrued Taxes | 742 | 651 |
| Accrued Interest | 183 | 183 |
| Customer Deposits | 382 | 571 |
| Other | 624 | 842 |
| TOTAL | 4,561 | 5,460 |
| NONCURRENT LIABILITIES | | |
| Long-term Debt | 11,845 | 11,073 |
| Long-term Risk Management Liabilities | 418 | 723 |
| Deferred Income Taxes | 4,792 | 4,810 |
| Regulatory Liabilities and Deferred Investment Tax Credits | 2,819 | 2,747 |
| Asset Retirement Obligations | 962 | 936 |
| Employee Benefits and Pension Obligations | 339 | 355 |
| Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2 | 152 | 157 |
| Deferred Credits and Other | 809 | 762 |
| TOTAL | 22,136 | 21,563 |
| TOTAL LIABILITIES | 26,697 | 27,023 |
| Cumulative Preferred Stock Not Subject to Mandatory Redemption | 61 | 61 |
| Commitments and Contingencies (Note 5) | | |
| COMMON SHAREHOLDERS' EQUITY | | |
| Common Stock Par Value \$6.50: | | |
| <u>2006</u> | <u>2005</u> | |
| Shares Authorized | 600,000,000 | 600,000,000 |
| Shares Issued | 415,446,501 | 415,218,830 |
| (21,499,992 shares were held in treasury at June 30, 2006 and December 31, 2005) | 2,700 | 2,699 |
| Paid-in Capital | 4,138 | 4,131 |
| Retained Earnings | 2,550 | 2,285 |
| Accumulated Other Comprehensive Income (Loss) | 38 | (27) |
| TOTAL | 9,426 | 9,088 |
| TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY | \$ 36,184 | \$ 36,172 |

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2006 and 2005
(in millions)
(Unaudited)

| | 2006 | 2005 |
|--|---------|---------|
| OPERATING ACTIVITIES | | |
| Net Income | \$ 556 | \$ 576 |
| Less: Income from Discontinued Operations | (6) | (4) |
| Income from Continuing Operations | 550 | 572 |
| Adjustments for Noncash Items: | | |
| Depreciation and Amortization | 689 | 652 |
| Accretion of Asset Retirement Obligations | 30 | 35 |
| Deferred Income Taxes | 10 | (75) |
| Deferred Investment Tax Credits | (14) | (15) |
| Carrying Costs Income | (63) | (56) |
| Mark-to-Market of Risk Management Contracts | (43) | 43 |
| Amortization of Nuclear Fuel | 25 | 27 |
| Deferred Property Taxes | 12 | 10 |
| Pension Contributions to Qualified Plan Trusts | - | (204) |
| Fuel Over/Under-Recovery, Net | 128 | (45) |
| Gain on Sales of Assets and Equity Investments, Net | (71) | (115) |
| Change in Other Noncurrent Assets | 109 | (59) |
| Change in Other Noncurrent Liabilities | (42) | (83) |
| Changes in Certain Components of Working Capital: | | |
| Accounts Receivable, Net | 202 | 155 |
| Fuel, Materials and Supplies | (140) | (29) |
| Accounts Payable | (17) | 63 |
| Accrued Taxes | 90 | 172 |
| Customer Deposits | (189) | (34) |
| Other Current Assets | 86 | 63 |
| Other Current Liabilities | (215) | (95) |
| Net Cash Flows From Operating Activities | 1,137 | 982 |
| INVESTING ACTIVITIES | | |
| Construction Expenditures | (1,625) | (1,020) |
| Change in Other Temporary Cash Investments, Net | 3 | (103) |
| Purchases of Investment Securities | (5,647) | (2,141) |
| Sales of Investment Securities | 5,596 | 2,213 |
| Proceeds from Sales of Assets | 123 | 1,500 |
| Other | (36) | 9 |
| Net Cash Flows From (Used For) Investing Activities | (1,586) | 458 |
| FINANCING ACTIVITIES | | |
| Issuance of Common Stock | 6 | 28 |
| Repurchase of Common Stock | - | (427) |
| Change in Short-term Debt, Net | 147 | (9) |
| Issuance of Long-term Debt | 1,081 | 1,660 |

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| | | |
|---|---------------|----------------|
| Retirement of Long-term Debt | (676) | (2,040) |
| Dividends Paid on Common Stock | (291) | (273) |
| Other | 30 | (92) |
| Net Cash Flows From (Used For) Financing Activities | 297 | (1,153) |
| Net Increase (Decrease) in Cash and Cash Equivalents | (152) | 287 |
| Cash and Cash Equivalents at Beginning of Period | 401 | 320 |
| Cash and Cash Equivalents at End of Period | \$ 249 | \$ 607 |

SUPPLEMENTARY INFORMATION

| | | |
|--|--------|--------|
| Cash Paid for Interest, Net of Capitalized Amounts | \$ 316 | \$ 322 |
| Cash Paid for Income Taxes, Net of Refunds | 123 | 86 |
| Noncash Acquisitions Under Capital Leases | 37 | 22 |
| Construction Expenditures Included in Accounts Payable at June 30, | 273 | 123 |
| Acquisition of Nuclear Fuel in Accounts Payable at June 30, | 26 | - |
| Disposition of Liabilities Related to Divestitures | - | 22 |

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDERS'
EQUITY AND
COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2006 and 2005
(in millions)
(Unaudited)

| | Common Stock | | | Accumulated Other Comprehensive Income | | Total |
|---|--------------|----------|--------------------|---|----------|----------|
| | Shares | Amount | Paid-in Capital | Retained Earnings | (Loss) | |
| DECEMBER 31, 2004 | 405 | \$ 2,632 | \$ 4,203 | \$ 2,024 | \$ (344) | \$ 8,515 |
| Issuance of Common Stock | 1 | 6 | 22 | | | 28 |
| Common Stock Dividends | | | | (273) | | (273) |
| Repurchase of Common Stock | | | (427) | | | (427) |
| Other | | | 15 | | | 15 |
| TOTAL | | | | | | 7,858 |
| COMPREHENSIVE INCOME | | | | | | |
| Other Comprehensive 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 | | | | 576 | | 576 |
| TOTAL COMPREHENSIVE INCOME | | | | | | 524 |
| JUNE 30, 2005 | 406 | \$ 2,638 | \$ 3,813 | \$ 2,327 | \$ (396) | \$ 8,382 |
| DECEMBER 31, 2005 | 415 | \$ 2,699 | \$ 4,131 | \$ 2,285 | \$ (27) | \$ 9,088 |
| Issuance of Common Stock | | 1 | 5 | | | 6 |
| Common Stock Dividends | | | | (291) | | (291) |
| Other | | | 2 | | | 2 |
| TOTAL | | | | | | 8,805 |
| COMPREHENSIVE INCOME | | | | | | |
| Other Comprehensive Income, Net of Tax: | | | | | | |
| Cash Flow Hedges, Net of Tax of \$29 | | | | | 54 | 54 |
| Securities Available for Sale, Net of Tax of \$6 | | | | | 11 | 11 |
| NET INCOME | | | | 556 | | 556 |
| TOTAL COMPREHENSIVE INCOME | | | | | | 621 |
| JUNE 30, 2006 | 415 | \$ 2,700 | \$ 4,138 | \$ 2,550 | \$ 38 | \$ 9,426 |

See Condensed Notes to Condensed Consolidated Financial Statements.

**AMERICAN ELECTRIC POWER, INC. AND SUBSIDIARY COMPANIES
INDEX TO CONDENSED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS**

1. Significant Accounting Matters
 2. New Accounting Pronouncements
 3. Rate Matters
 4. Customer Choice and Industry Restructuring
 5. Commitments and Contingencies
 6. Guarantees
 7. Company-wide Staffing and Budget Review
 8. Dispositions, Discontinued Operations and Assets Held for Sale
 9. Benefit Plans
 10. Stock-Based Compensation
 11. Income Taxes
 12. Business Segments
 13. Financing Activities
-

**AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS**

1. SIGNIFICANT ACCOUNTING MATTERS

General

The accompanying unaudited interim financial statements should be read in conjunction with the 2005 Annual Report as incorporated in and filed with our 2005 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.

Components of Accumulated Other Comprehensive Income (Loss)

Accumulated Other Comprehensive Income (Loss) is included on our Condensed Consolidated Balance Sheets in the common shareholders' equity section. The following table provides the components that constitute the balance sheet amount in Accumulated Other Comprehensive Income (Loss):

| Components | June 30, 2006 | December 31, 2005 |
|---|--------------------------|------------------------------|
| | (in millions) | |
| Securities Available for Sale, Net of Tax | \$ 30 | \$ 19 |
| Cash Flow Hedges, Net of Tax | 27 | (27) |
| Minimum Pension Liability, Net of Tax | (19) | (19) |
| Total | \$ 38 | \$ (27) |

At June 30, 2006, we expect to reclassify approximately \$29 million of net gains 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. Forty-two months is the maximum length of time that we hedge our exposure to variability in future cash flows with contracts designated as cash flow hedges.

Stock-Based Compensation Plans

At June 30, 2006, we have options outstanding under two stock-based employee compensation plans: The Amended and Restated American Electric Power System Long-Term Incentive Plan and the Central and South West Corporation Long-Term Incentive Plan. We also grant performance share units, phantom stock units, restricted shares and restricted stock units to employees.

On January 1, 2006, we adopted SFAS No. 123 (revised 2004), "Share-Based Payment," (SFAS 123R) which requires the measurement and recognition of compensation expense for all share-based payment awards made to employees and directors including stock options and employee stock purchases based on estimated fair values. See the SFAS 123 (revised 2004) "Share-Based Payment" section of Note 2 for additional discussion.

In conjunction with the adoption of SFAS 123R, we changed our method of attributing the value of stock-based compensation to expense from the accelerated multiple-option approach to the straight-line single-option method. Compensation expense for all share-based payment awards granted prior to January 1, 2006 will continue to be recognized using the accelerated multiple-option approach while compensation expense for all share-based payment

awards granted on or after January 1, 2006 is recognized using the straight-line single-option method. As stock-based compensation expense recognized in our Condensed Consolidated Statements of Operations for the three and six months periods ended June 30, 2006 is based on awards ultimately expected to vest, it has been reduced for estimated forfeitures. SFAS 123R requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates. In our pro forma information presented below as required under SFAS 123 for the periods prior to 2006, we accounted for forfeitures as they occurred.

For the three and six months ended June 30, 2005, no stock option expense was reflected in Net Income as we accounted for stock options using the intrinsic value method under Accounting Principles Board (APB) Opinion No. 25, "Accounting For Stock Issued to Employees." Under the intrinsic value method, no stock option expense is recognized when the exercise price of the stock options granted equals the fair value of the underlying stock at the date of grant. No options were granted during the first six months of 2005. For the three and six months ended June 30, 2006 and 2005, compensation cost is included in Net Income for the performance share units, phantom stock units, restricted shares, restricted stock units and the Director's stock units. See Note 10 for additional discussion.

Pro Forma Information Under SFAS 123, "Accounting for Stock-Based Compensation," for Periods Presented Prior to January 1, 2006

The following table shows the effect on our Net Income and Earnings Per Share as if we had applied fair value measurement and recognition provisions of SFAS 123 to stock-based employee and director compensation awards for the three and six months ended June 30, 2005:

| | Three Months Ended | Six Months Ended |
|--|---|-----------------------------|
| | (in millions, except per share data) | |
| Net Income, as reported | \$ 221 | \$ 576 |
| Add: Stock-based compensation expense included in reported Net Income, net of related tax effects | 4 | 6 |
| Deduct: Stock-based compensation expense determined under fair value based method for all awards, net of related tax effects | (4) | (6) |
| Pro Forma Net Income | \$ 221 | \$ 576 |
| Earnings Per Share: | | |
| Basic - as Reported | \$ 0.58 | \$ 1.48 |
| Basic - Pro Forma (a) | \$ 0.58 | \$ 1.48 |
| Diluted - as Reported | \$ 0.58 | \$ 1.48 |
| Diluted - Pro Forma (a) | \$ 0.58 | \$ 1.48 |

(a) The pro forma amounts are not representative of the effects on reported net income for future years.

Earnings Per Share (EPS)

The following table presents our basic and diluted Earnings Per Share (EPS) calculations included in our Condensed Consolidated Statements of Operations:

| | | |
|-------------|------------------------------------|-------------|
| 2006 | Three Months Ended June 30, | 2005 |
|-------------|------------------------------------|-------------|

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(in millions, except per share data)
\$/share

| Earnings applicable to common stock | \$ | 175 | | \$ | 221 |
|--|----|-------|----|------|-------|
| Average number of basic shares outstanding | | 393.7 | \$ | 0.44 | 384.2 |
| Average dilutive effect of: | | | | | |
| Performance Share Units | | 1.4 | | - | 0.8 |
| Stock Options | | 0.2 | | - | 0.3 |
| Restricted Stock Units | | 0.1 | | - | 0.1 |
| Restricted Shares | | 0.1 | | - | - |
| Average number of diluted shares outstanding | | 395.5 | \$ | 0.44 | 385.4 |

Six Months Ended June 30,

2006 2005
(in millions, except per share data)
\$/share

| Earnings applicable to common stock | \$ | 556 | | \$ | 576 |
|--|----|-------|----|------|-------|
| Average number of basic shares outstanding | | 393.7 | \$ | 1.41 | 388.6 |
| Average dilutive effect of: | | | | | |
| Performance Share Units | | 1.4 | | - | 0.8 |
| Stock Options | | 0.2 | | - | 0.3 |
| Restricted Stock Units | | 0.1 | | - | 0.1 |
| Restricted Shares | | 0.1 | | - | - |
| Average number of diluted shares outstanding | | 395.5 | \$ | 1.41 | 389.8 |

Our stock option and other equity compensation plans are discussed in Note 10.

Related Party Transactions

Three Months Ended
June 30,
2006 2005
(in millions)

Six Months Ended
June 30,
2006 2005
(in millions)

| | | | | | |
|--|--|----|----|----|-----|
| AEP Consolidated Purchased Energy: | | | | | |
| Ohio Valley Electric Corporation (43.47% Owned) | | 58 | \$ | 48 | \$ |
| | | | | | 113 |
| Sweeny Cogeneration Limited Partnership (50% Owned) | | 28 | | 31 | 62 |
| | | | | | 91 |
| | | | | | 60 |
| AEP Consolidated Other Revenues - Barging and Other Transportation | | | | | |
| Services - Ohio Valley Electric Corporation (43.47% Owned) | | 8 | | 4 | 15 |
| | | | | | 8 |

Reclassifications

Certain prior period financial statement items have been reclassified to conform to current period presentation.

On our Condensed Consolidated Statements of Cash Flows, we included purchases and sales of investments within our Spent Nuclear Fuel and Decommissioning Trusts as a component of Investing Activities rather than Operating Activities.

These revisions had no impact on our previously reported results of operations, financial condition or changes in shareholders' equity.

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of exposure drafts or final pronouncements, we thoroughly 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 in 2006 that we have determined relate to our operations.

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

In December 2004, the FASB issued SFAS 123R. 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 APB Opinion No. 25, "Accounting for Stock Issued to Employees." We recorded an insignificant cumulative effect of a change in accounting principle in the first quarter of 2006 for the effect of initially applying the statement primarily reflected in Maintenance and Other Operation on our Condensed Consolidated Statements of Operations.

In March 2005, the SEC issued Staff Accounting Bulletin No. 107, "Share-Based Payment" (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. Also, the FASB issued three FASB Staff Positions (FSP) during 2005 and one in February 2006 that provided additional implementation guidance. We applied the principles of SAB 107 and the applicable FSPs in conjunction with our adoption of SFAS 123R.

We adopted SFAS 123R in the first quarter of 2006 using the modified prospective method. This method requires us to record compensation expense for all awards granted after the time of adoption and 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 is based on the grant-date fair value of the equity award. Stock-based compensation expense recognized during the period is based on the value of the portion of share-based payment awards that is ultimately expected to vest during the period. Stock-based compensation expense recognized in our Condensed Consolidated Statements of Operations for the three and six months ended June 30, 2006 includes compensation expense for share-based payment awards granted prior to, but not yet vested as of, January 1, 2006 based on the grant date fair value estimated in accordance with the pro forma provisions of SFAS 123 and compensation expense for the share-based payment awards granted subsequent to January 1, 2006 based on the grant date fair value estimated in accordance with the provisions of SFAS 123R. Our implementation of SFAS 123R did not materially affect our results of operations, cash flows or financial condition.

EITF Issue 06-3 "How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation)" (EITF 06-3)

In June 2006, the EITF reached a consensus on the income statement presentation of various types of taxes. The scope of this issue includes any tax assessed by a governmental authority that is directly imposed on a revenue-producing transaction between a seller and a customer and may include, but is not limited to, sales, use, value added, and some excise taxes. The presentation of taxes within the scope of this issue on either a gross (included in revenues and costs)

or a net (excluded from revenues) basis is an accounting policy decision that should be disclosed pursuant to APB Opinion No. 22, "Disclosure of Accounting Policies." The EITF's decision on gross/net presentation requires that any such taxes reported on a gross basis be disclosed on an aggregate basis in interim and annual financial statements, for each period for which an income statement is presented, if those amounts are significant.

EITF 06-3 is effective for fiscal years beginning after December 15, 2006. We have not completed the process of determining the effect of this interpretation on our financial statements.

FASB Interpretation No. 48 "Accounting for Uncertainty in Income Taxes" (FIN 48)

In July 2006, the FASB issued FIN 48 which clarifies the application of SFAS 109, "Accounting for Income Taxes." FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements by prescribing a recognition threshold (whether a tax position is more likely than not to be sustained) without which, the benefit of that position is not recognized in the financial statements. It requires a measurement determination for recognized tax positions based on the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition.

FIN 48 requires that the cumulative effect of applying this interpretation be reported and disclosed as an adjustment to the opening balance of retained earnings for that fiscal year and presented separately. FIN 48 is effective for fiscal years beginning after December 15, 2006. We have not completed the process of determining the effect of this interpretation on our financial statements.

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 and financial position that may result from any such future changes. The FASB is currently working on several projects including fair value measurements, business combinations, revenue recognition, pension and postretirement benefit plans, liabilities and equity, earnings per share calculations, leases, insurance, subsequent events and related tax impacts. We also expect to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on our future results of operations and financial position.

3. RATE MATTERS

As discussed in our 2005 Annual Report, our subsidiaries are involved in rate and regulatory proceedings at the FERC and state commissions. The Rate Matters note within our 2005 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact results of operations and cash flows. Rate matters that are not believed to be reasonably likely to affect future results of operations and cash flows are not included in this report or the 2005 Annual Report. The following sections discuss ratemaking developments in 2006 updating the 2005 Annual Report.

APCo Virginia Environmental and Reliability Costs

The Virginia Electric Restructuring Act includes a provision that permits recovery, during the extended capped rate period ending December 31, 2010, of incremental environmental compliance and transmission and distribution (T&D) system reliability (E&R) costs prudently incurred after July 1, 2004. In 2005, APCo filed a request with the Virginia SCC and updated it through supplemental testimony seeking recovery of \$21 million of incremental E&R costs incurred from July 2004 through September 2005. Through June 30, 2006, APCo deferred \$37 million of incurred incremental E&R costs.

In January 2006, the Virginia SCC staff proposed that APCo be allowed to increase its electric rates at an ongoing level of \$20 million to recover current, rather than past, incremental E&R costs. The staff proposal would effectively disallow the recovery of costs incurred prior to the authorization and implementation of new rates, including all incremental E&R costs that were deferred as a regulatory asset. At the E&R hearings, which concluded in March 2006, the staff amended its testimony to recommend a \$24 million increase in APCo's ongoing rates. We believe the staff's proposal is contrary to the statute and an October 2005 Virginia SCC order, which denied APCo's original request to recover projected costs in favor of the Virginia SCC's interpretation that the law only permits recovery of actual incremental E&R costs that the commission finds prudent.

If the Virginia SCC properly implements the statute and its related October 2005 order, notwithstanding use of estimates, we should be able to recover all of our prudently incurred E&R costs. However, if the Virginia SCC reverses its position and adopts the staff's recommendations or denies recovery of any of APCo's deferred E&R costs, future results of operations and cash flows would be adversely impacted.

APCo Virginia Base Rate Case

In May 2006, APCo filed a request with the Virginia SCC seeking an increase in base rates of \$225 million to recover increasing costs including a return on equity of 11.5%. In addition, APCo requested to move off-system sales margins, currently credited to customers through base rates, to the fuel factor where they can be adjusted annually. APCo also proposed to share the off-system sales margins with the customers. This proposed off-system sales fuel rate credit of \$27 million partially offsets the \$225 million requested increase in base rates for a net increase in revenues of \$198 million. The major components of the \$225 million rate request include \$73 million for the impact of removing off-system sales margins from the rate year ending September 30, 2007, \$60 million due to projected net plant additions through September 30, 2007 and \$48 million for return on equity. In May 2006, the Virginia SCC issued an order, consistent with Virginia law, placing the full requested base rate increase of \$225 million into effect October 2, 2006, subject to refund. Hearings are scheduled to begin in December 2006. We are unable to predict the ultimate effect of this filing on future revenues, cash flows and financial condition.

APCo and WPCo West Virginia Rate Case

In July 2006, the WVPSC approved the settlement agreement APCo and WPCo reached with the WVPSC staff and intervenors in the West Virginia rate case filed in 2005. The settlement agreement provided for an initial overall increase in rates of \$44 million effective July 28, 2006 comprised of:

- A \$56 million increase in Expanded Net Energy Cost (ENEC) for fuel and purchased power expenses;
- A \$23 million special construction surcharge providing recovery of the costs of scrubbers and the Wyoming-Jacksons Ferry 765 kV line to date;
- An \$18 million general base rate reduction based on a return on equity of 10.5%, of which \$9 million relates to a reduction in depreciation expense which affects cash flows but not earnings; and
- A \$17 million credit to refund a portion of deferred prior over-recoveries of ENEC costs of \$51 million, currently recorded in regulatory liabilities on the Condensed Consolidated Balance Sheets. Therefore, this item impacts cash flows but has no effect on earnings.

In addition, the agreement provides a surcharge mechanism that allows APCo and WPCo to adjust their rates annually for the timely recovery in each of the next three years of the incremental cost of ongoing environmental investments in scrubbers at APCo's Mountaineer and John Amos power plants and the costs of the Wyoming-Jacksons Ferry line. Although the amount of these annual surcharge increases cannot be determined until the incremental costs are known and reviewed by the WVPSC, APCo estimates that they will result in an annual increase in revenues of \$36 million effective July 1, 2007, \$14 million effective July 1, 2008 and \$18 million effective July 1, 2009.

The settlement further provides for the reinstatement of the ENEC mechanism effective July 1, 2006 with over/under recovery deferral accounting and annual ENEC proceedings to affect annual rate adjustments for changes in fuel and purchased power costs beginning in 2007. The settlement provides for the return to customers of the remaining portion of the prior ENEC regulatory liability including interest at a LIBOR rate on the unrefunded balance in future ENEC proceedings.

I&M Depreciation Study Filing

In December 2005, I&M filed a petition with the IURC seeking authorization to revise its book depreciation rates applicable to its electric utility plant in service effective January 1, 2006. Based on a depreciation study included in the filing, I&M recommended a decrease in pretax annual depreciation expense of approximately \$69 million on an Indiana jurisdictional basis reflecting an NRC-approved 20-year extension of the Cook Plant licenses for Units 1 and 2 and an extension of the service life of the Tanners Creek coal-fired generating units. This petition is not a request for a change in customers' electric service rates. Intervenors filed testimony in March 2006 arguing that the book depreciation rates should not be revised until the Indiana rate cap ends in July 2007 or until base rates are revised. I&M filed its rebuttal testimony in April 2006. A public hearing was held in May 2006 and the final brief was filed in June 2006. As proposed by I&M, the book depreciation expense reduction would increase earnings, but would not impact cash flows until electric service rates are revised. If approved by the IURC, I&M will currently reduce its book depreciation expense from the approved effective date forward. We are awaiting the IURC order.

KPCo Environmental Surcharge Filing

In June 2006, KPCo filed a notice of its intent to file an amended environmental compliance plan and revised tariff to implement an adjusted environmental surcharge on or after August 16, 2006.

KPCo Rate Filing

In March 2006, the KPSC approved the settlement agreement in KPCo's 2005 base rate case. The approved agreement provides for a \$41 million annual increase in revenues effective March 30, 2006 and the retention of the existing environmental surcharge tariff. No return on equity is specified by the settlement terms except to note that KPCo will use a 10.5% return on equity to calculate the environmental surcharge tariff and AFUDC.

PSO Fuel and Purchased Power and its Possible Impact on AEP East companies and AEP West companies

In 2002, PSO under-recovered \$44 million 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 proposed collection of those reallocated costs over 18 months. In August 2003, the OCC staff filed testimony recommending PSO recover \$42 million of the reallocated purchased power costs over three years and PSO reduced its regulatory asset deferral by \$2 million. The OCC subsequently expanded the case to include a full prudence review of PSO's 2001 through 2003 fuel and purchased power practices. In January 2006, the OCC staff and intervenors issued supplemental testimony alleging that AEP deviated from the FERC-approved method of allocating off-system sales margins between AEP East companies and AEP West companies and among AEP West companies. The OCC staff proposed that the OCC offset the \$42 million of under-recovered fuel with their proposed reallocation of off-system sales margins of \$27 million to \$37 million and with \$9 million attributed to wholesale customers, which they claimed had not been refunded. In February 2006, the OCC staff filed a report concluding that the \$9 million of reallocated purchased power costs assigned to wholesale customers has been refunded, thus removing that issue from their recommendation.

In 2004, an Oklahoma ALJ found that the OCC lacks authority to examine whether PSO deviated from the FERC-approved allocation methodology and held that any such complaints should be addressed at the FERC. The OCC has not ruled on appeals by intervenors of the ALJ's finding. In September 2005, the United States District Court

for the Western District of Texas issued an order in a TNC fuel proceeding, preempting the PUCT from reallocating off-system sales margins between the AEP East companies and AEP West companies. The federal court agreed that the FERC has sole jurisdiction over that allocation. The PUCT appealed the ruling.

PSO does not agree with the intervenors' and the OCC staff's recommendations and proposals and will defend its position vigorously. If the OCC denies recovery of any portion of the \$42 million under-recovery of reallocated costs or offsets under-recovered fuel deferrals with additional reallocated off-system sales margins, our future results of operations and cash flows could be adversely affected. However, if the position taken by the federal court in Texas applies to PSO's case, the OCC could be preempted from disallowing fuel recoveries for alleged improper allocations of off-system sales margins between AEP East companies and AEP West companies. The OCC or another party may file a complaint at the FERC alleging the allocation of off-system sales margins adopted by PSO is improper which could result in an adverse effect on future results of operations and cash flows for AEP and the AEP East companies. To date, there has been no claim asserted at the FERC that AEP deviated from the approved allocation methodologies. Management is unable to predict the ultimate effect, if any, of these Oklahoma fuel clause proceedings and any future FERC proceedings on future results of operations, cash flows and financial condition.

In June 2005, the OCC issued an order directing its staff to conduct a prudence review of PSO's fuel and purchased power practices for the year 2003. Both the OCC staff and Attorney General of Oklahoma filed testimony, finding no disallowances in the test year data. However, an intervenor filed testimony in June 2006, proposing the disallowance of \$22 million in fuel costs based on a historical review of potential hedging opportunities that existed during the year. A hearing is scheduled for August 2006.

In February 2006, a law was enacted requiring the OCC to conduct prudence reviews on all generation and fuel procurement processes, practices and costs on either a two or three-year cycle depending on the number of customers served. PSO is subject to biennial reviews. The OCC staff indicated that it expects the review process to begin in the fourth quarter of 2006.

Management cannot predict the outcome of this review or planned future reviews, but believes that PSO's fuel and purchased power procurement practices and costs are prudent and properly incurred. If the OCC disagrees and disallows fuel or purchased power costs including the unrecovered 2002 reallocation of such costs incurred by PSO, it would have an adverse effect on future results of operations and cash flows.

SWEPCo Louisiana Fuel Inquiry

In March 2006, the Louisiana Public Service Commission (LPSC) closed its inquiry into SWEPCo's fuel and purchased power procurement activities during the period January 1, 2005 through October 31, 2005. The LPSC approved the LPSC staff's report, which concluded that SWEPCo's activities were appropriate and did not identify any disallowances or areas for improvement.

SWEPCo PUCT Staff Review of Earnings

In October 2005, the staff of the PUCT reported the results of its review of SWEPCo's year-end 2004 earnings. Based on the staff's adjustments to the information submitted by SWEPCo, the report indicates that SWEPCo is receiving excess revenues of approximately \$15 million. The staff engaged SWEPCo in discussions to reconcile the earnings calculation and to consider possible ways to address the results. After those discussions, the PUCT staff informed SWEPCo in April 2006 that they would not pursue the matter further.

SWEPCo Louisiana Compliance Filing

In October 2002, SWEPCo filed with the LPSC detailed financial information typically utilized in a revenue requirement filing, including a jurisdictional cost of service. This filing was required by the LPSC as a result of its

order approving the merger between AEP and CSW. In April 2004, at the request of the LPSC, SWEPCo filed updated financial information with a test year ending December 31, 2003. Both filings indicated that SWEPCo's rates should not be reduced. Subsequently, direct testimony was filed by the LPSC staff's consultants recommending a \$15 million reduction in SWEPCo's Louisiana jurisdictional base rates based on an 8.95% return on equity and the disallowance of projected increased pension expense. Due to multiple delays, in April 2006, the LPSC and SWEPCo agreed to update the financial information based on a 2005 test year. SWEPCo filed updated financial review schedules in May 2006 showing a return on equity of 9.44%. In July 2006, the LPSC staff's consultants filed direct testimony recommending a base rate reduction in the range of \$12 million to \$20 million for SWEPCo's Louisiana jurisdiction customers, which included a 10% return on equity. The recommended reduction range is subject to SWEPCo validating certain ongoing operations and maintenance expense levels and the recommended base rate reduction does not include the impact of a proposed consolidated federal income tax adjustment, which would increase the proposed rate reduction. SWEPCo intends to file rebuttal testimony refuting the consultant's recommendations. Hearings are scheduled for October 2006. A decision is not expected until late 2006 at the earliest. At this time, management is unable to predict the outcome of this proceeding. If a rate reduction is ultimately ordered, it would adversely impact future results of operations and cash flows.

ERCOT Price-to-Beat (PTB) Fuel Factor Appeal

Several parties including the Office of Public Utility Counsel and cities served by both TCC and TNC appealed the PUCT's December 2001 orders establishing initial PTB fuel factors for Mutual Energy CPL and Mutual Energy WTU (TCC's and TNC's former affiliated REPs, respectively). In June 2003, the District Court ruled the PUCT record lacked substantial evidence regarding the effect of loss of load due to retail competition on the generation requirements of both Mutual Energy WTU and Mutual Energy CPL and on the PTB rates. In an opinion issued on July 28, 2005, the Texas Court of Appeals reversed the District Court. The cities appealed the appeals court decision to the Texas Supreme Court. Management cannot predict the outcome of further appeals, but a reversal of the favorable court of appeals decision regarding the loss of load issue could result in the issue being returned to the PUCT for further consideration. If the PUCT were to reverse its decision and order refunds of PTB revenues, it could adversely impact results of operations and cash flows.

RTO Formation/Integration Costs

In 2005, the FERC approved the amortization of approximately \$18 million of deferred RTO formation/integration costs not billed by PJM over 15 years and \$17 million of deferred PJM-billed integration costs over 10 years. Total amortization related to such costs was \$1 million in both the second quarter of 2006 and 2005. In the first half of both 2006 and 2005, total amortization related to such costs was \$2 million. As of June 30, 2006 and December 31, 2005, the AEP East companies had \$30 million and \$31 million, respectively, of deferred unamortized RTO and PJM formation/integration costs.

In a December 2005 order, the FERC approved the inclusion of a separate rate in the PJM AEP zone OATT to recover the amortization of deferred RTO formation/integration costs not billed by PJM of \$2 million per year. The AEP East companies will be responsible for paying the majority of the amortized costs assigned by the FERC to the AEP East zone since their internal load is the bulk (about 85%) of the transmission load in the AEP zone.

In May 2006, the FERC approved a settlement that provides for recovery over a ten-year period of 41% of our deferred PJM-billed and incurred integration costs and related carrying charges from the PJM region outside of the AEP zone and the remaining 59% from within the AEP zone. As a result, the AEP East companies are responsible for paying approximately 50% of the amortized PJM-billed integration costs (59% of costs to be recovered within the AEP zone times 85% internal load factor within the AEP zone) for their internal load usage of the transmission system.

CSPCo, OPCo and KPCo are recovering the amortization of RTO formation/integration costs billed to our AEP East companies in Ohio and Kentucky. APCo received approval to include the amortization of RTO formation/integration costs in retail rates in West Virginia effective July 28, 2006. In Virginia, APCo recently filed a base rate case which includes recovery of these costs. In Indiana, I&M is subject to a rate cap until June 30, 2007.

Until APCo and I&M can adjust their retail rates to recover the amortization of their RTO-related deferred costs, results of operations and cash flows will be adversely affected by approximately one-third of the amortizations. APCo will recover its RTO amortizations starting in late July 2006 in West Virginia and is scheduled to commence recovery in early October 2006 in Virginia. The new Virginia rates will be subject to refund. If the Virginia or Indiana commissions disallow recovery of any portion of the billed amortization of deferred RTO formation/integration costs, it would result in a write-off of up to one-third of the total remaining deferred balance and thereby, adversely impact future results of operations and cash flows.

Transmission Rate Proceedings at the FERC

SECA Revenue Subject to Refund

In accordance with FERC orders, we collected SECA rates to mitigate lost through-and-out transmission service (T&O) revenues from December 1, 2004 through March 31, 2006, when SECA rates expired. Intervenors objected to the SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and indicated that the SECA rate revenues are collected subject to refund or surcharge. The AEP East companies recognized net SECA revenues as follows:

| | (in millions) |
|--|----------------------|
| Three Months Ended June 30, 2006 | \$ - |
| Three Months Ended June 30, 2005 | 32 |
| Six Months Ended June 30, 2006 | 35 |
| Six Months Ended June 30, 2005 | 57 |
| Total Net SECA Revenues Recognized Through June 2006 | 174 |

Approximately \$19 million of these recorded SECA revenues billed by PJM were never collected. The AEP East companies filed a motion with the FERC to force payment of these SECA billings. The FERC has not yet acted on the motion.

Intervenors in the SECA proceeding are objecting to the SECA rates and our method of determining those rates. SECA hearings were held in May 2006 to determine whether any of the SECA revenues should be refunded. Management negotiated settlements with certain major intervenors and is engaged in settlement talks with other intervenors. Based on those negotiations, the AEP East companies provided for \$22 million in net refunds, of which \$18 million was recorded in the second quarter of 2006 in Utility Operations Revenues in the Condensed Consolidated Statements of Operations. Unless all intervenor claims are fully settled, the ALJ is expected to issue an initial decision in the third quarter of 2006. At this time, management is unable to determine whether the outcome of the FERC's SECA rate proceeding and AEP's filed motion to force payment of unpaid invoices will have any additional adverse impact on future results of operations and cash flows.

AEP East Transmission Revenue Requirement and Rates

In December 2005, the FERC approved an uncontested settlement allowing increases in our wholesale transmission OATT rates in three steps: first, beginning retroactively on November 1, 2005, second, beginning on April 1, 2006 when the SECA revenues were eliminated and third, beginning on August 1, 2006. We estimate that this rate increase will increase wholesale transmission revenues by \$22 million in 2006 and \$28 million in 2007.

The Elimination of T&O and SECA Rates and the FERC PJM Regional Transmission Rate Proceeding

In a separate proceeding, at our urging, the FERC instituted an investigation of PJM's zonal rate regime, indicating that the present rate regime may need to be replaced through establishment of regional rates that would compensate AEP, among other transmission owners, for the regional transmission facilities they provide to PJM, which provides service for the benefit of customers throughout PJM. In September 2005, AEP and a nonaffiliated utility (Allegheny Power or AP) jointly filed a regional transmission rate design proposal with the FERC. This filing proposes and supports a new PJM rate regime generally referred to as Highway/Byway.

The following rate regimes have been proposed:

- AEP/AP proposed a Highway/Byway rate design in which:
 - The cost of all transmission facilities in the PJM region operated at 345 kV or higher would be included in a "Highway" rate that all load serving entities (LSEs) would pay based on peak demand.
 - The cost of transmission facilities operating at lower voltages would be collected in the zones where those costs are presently charged under PJM's existing rate design.
- In a competing Highway/Byway proposal, a group of LSEs proposed rates that would include 500 kV and higher existing facilities and some facilities at lower voltages in the Highway rate.
- Another proposal uses facilities 200 kV or higher in the Highway rate.
- In January 2006, the FERC staff issued testimony and exhibits supporting a PJM-wide flat rate or "Postage Stamp" type of rate design that would include all transmission facilities.

All of these proposals are being challenged by a majority of transmission owners in the PJM region, who favor continuation of the PJM rate design. Hearings were held in April 2006.

The projected impact on the AEP East companies' revenues by plan follows:

- The AEP/AP Highway/Byway rate design would result in incremental net revenues of approximately \$125 million per year for the transmission-owning AEP East companies.
- The competing Highway/Byway proposals filed by others would also produce incremental net revenues to the AEP East transmission-owning companies, but at a much lower level.
- The staff rate design would produce slightly more net revenue for AEP than the original AEP/AP proposal, when fully effective; however, the staff recommended a phase-in plan that would take an estimated six years to complete.

From the elimination of through and out (T&O) rates in December 2004 through the expiration of SECA rates on March 31, 2006, SECA transition rates failed to fully compensate the AEP East companies for their lost T&O revenues. Effective with the expiration of the SECA transition rates on March 31, 2006, the increase in the AEP East zonal transmission rates applicable to AEP's internal load and wholesale transmission customers in AEP's zone was not sufficient to replace the prior T&O service or temporary SECA transition rate revenues; however, a favorable outcome in the PJM regional transmission rate proceeding, made retroactive to April 1, 2006 could mitigate a large portion of the expected shortfall. Full mitigation of the effects of eliminated T&O revenues and the less favorable terminated SECA revenues will require cost recovery through state retail rate proceedings pending any resolution that may result from the above FERC regional transmission rate proceeding. The status of such state retail rate proceedings is as follows:

- In Kentucky, KPCo settled a rate case, which provided for the recovery of its share of the transmission revenue reduction starting March 30, 2006.

In Ohio, CSPCo's and OPCo are recovering the FERC approved OATT which reflects their share of the full transmission revenue requirement retroactive to April 1, 2006 under a May 2006 PUCO order.

- In West Virginia, APCo settled a rate case, which provided for the recovery of its share of the T&O/SECA transmission revenue reduction beginning July 28, 2006.
- In Virginia, APCo filed a request for revised rates, which includes recovery of its share of the T&O/SECA transmission revenue reduction starting October 2, 2006, subject to refund.
- In Indiana, I&M is precluded by a rate cap from raising its rates until July 1, 2007.

We presently recover from retail customers approximately 65% of the reduction in transmission revenues of \$128 million a year. On October 2, 2006, subject to refund in Virginia, that percentage will increase to 80%.

In July 2006, the ALJ who heard the regional rate case for the FERC rendered an initial decision recommending that the current transmission rates in PJM are unjust and unreasonable and should be revised effective April 1, 2006. The ALJ recommended a regional rate design similar to the staff's favorable "Postage Stamp" rate design discussed above. If approved, the new rates should result in recovery of a significant portion of the revenues lost due to elimination of T&O and SECA rates. However, the ALJ recommended a phase-in of the new "Postage Stamp" rates, which limits increases of any one pricing zone to 10% per year. We estimate the phase-in may occur over a six-year period. Once approved, the impacts of the new PJM rate design will flow directly to wholesale customers and to retail customers in Ohio and West Virginia. In our other jurisdictions, the additional transmission revenues can be expected to reduce retail rates in future rate proceedings.

Management is unable to predict whether the FERC will approve either the ALJ's decision or another regional rate design. Parties to the proceeding have a right to file exceptions to both the ALJ initial decision and replies to the exceptions. We expect to file exceptions to certain aspects of the ALJ initial decision. The FERC will issue an order after considering the ALJ decision and subsequent filings.

Future results of operations, cash flows and financial condition would be adversely affected if the approved FERC transmission rates are not sufficient to replace the lost T&O/SECA revenues and the resultant increase in the AEP East companies' unrecovered transmission costs are not fully recovered in retail rates.

Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement

The SIA provides, among other things, for the methodology of sharing trading and marketing margins between the AEP East companies and AEP West companies. In March 2006, the FERC approved our proposed methodology to be used effective April 1, 2006 and beyond. The approved allocation methodology is based upon the location of the specific trading and marketing activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to the benefit of PSO and SWEPCo. Previously, the SIA allocation provided for a different method of sharing all such margins between both AEP East companies and AEP West companies. In February 2006, we filed with the FERC to remove TCC and TNC from the SIA and CSW Operating Agreement because those companies are in the final stages of exiting the generation business and have already ceased serving retail load. The FERC approved the removal of TCC and TNC from the SIA and CSW Operating Agreement effective May 1, 2006.

The impact on future results of operations and cash flows will depend upon the level of future margins by region and the status of cost recovery mechanisms and related sharing mechanisms by state. Our total trading and marketing margins are unaffected by the allocation methodology.

4. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING

We are affected by customer choice initiatives and industry restructuring. The Customer Choice and Industry Restructuring note in our 2005 Annual Report should be read in conjunction with this report to gain a complete understanding of material customer choice and industry restructuring matters without significant changes since year-end. The following paragraphs discuss significant events occurring in 2006 related to customer choice and industry restructuring and update the 2005 Annual Report.

TEXAS RESTRUCTURING

The PUCT issued an order in TCC's True-up Proceeding in February 2006, which determined that TCC's true-up regulatory asset was \$1.475 billion including carrying costs through September 2005. In December 2005, TCC adjusted its recorded net true-up regulatory asset to comply with the order. The PUCT issued an order on rehearing in April 2006, which made minor changes to, but otherwise affirmed, the February 2006 order. We appealed, seeking additional recovery consistent with the Texas Restructuring Legislation and related rules. Other parties appealed the PUCT's true-up order claiming it permits TCC to over-recover stranded generation costs and other true-up items.

TCC Securitization Proceeding

TCC filed an application in March 2006 requesting to recover through securitization \$1.8 billion of net stranded generation plant costs and related carrying costs through August 31, 2006. The \$1.8 billion did not include TCC's other true-up items, which total \$475 million and which would be refunded through a CTC over a period to be determined by the PUCT. See "CTC Proceeding for Other True-up Items" section of this note. Intervenors and the PUCT staff filed testimony regarding TCC's securitization request in April 2006. In May 2006, TCC filed a letter with the PUCT reducing its request by \$6 million and reduced the recorded net recoverable asset by that amount. In May 2006, TCC and the other parties filed a settlement with the PUCT, which further reduced the securitizable amount by \$77 million and settled several issues that would have delayed the sale of the securitization bonds. The PUCT approved the settlement in June 2006 authorizing \$1.697 billion including carrying costs through August 31, 2006, the assumed securitization date, plus estimated issuance costs of \$23 million, for a total of \$1.72 billion. We anticipate issuing the securitization bonds by the end of the third quarter of 2006.

Consistent with certain prior securitization determinations, the PUCT issued a specific order in the securitization proceeding that calculated a \$315 million cost-of-money benefit (\$310 million through June 30, 2006 of which \$70 million relates to the recorded benefit prior to June 30, 2006 and \$240 million relates to the unrecorded benefit subsequent to June 30, 2006) for ADFIT resulting from the securitization request. The PUCT included the \$315 million in the CTC refund of \$475 million. In June, we transferred the effects of the ADFIT on recorded carrying cost from the securitizable asset to the CTC refund, thereby increasing the carrying costs identified to the securitizable assets in the table below.

TCC performed a probability of recovery impairment test on its net true-up regulatory asset taking into account the treatment ordered by the PUCT and determined that the projected cash flows from the securitization less the proposed CTC refund would be more than sufficient to recover TCC's recorded net true-up regulatory asset. As a result, no additional impairment was recorded for the approved reduction in the amount to be securitized. However, the \$77 million agreed upon reduction in the securitizable amount will have a negative impact on future earnings.

The differences between the securitization amount ordered by the PUCT of \$1.7 billion and the recorded securitizable true-up regulatory asset of \$1.5 billion at June 30, 2006 are detailed in the table below:

| | (in millions) | |
|---|----------------------|------|
| Stranded Generation Plant Costs | \$ | 974 |
| Net Generation-related Regulatory Asset | | 249 |
| Excess Earnings | | (49) |

| | |
|---|----------|
| Recorded Net Stranded Generation Plant Costs | 1,174 |
| Recorded Debt Carrying Costs on Net Stranded Generation Plant Costs | 375 |
| Recorded Securitizable True-up Regulatory Asset | 1,549 |
| Unrecorded But Recoverable Equity Carrying Costs | 217 |
| Unrecorded Estimated July 2006 - August 2006 Debt Carrying Costs | 17 |
| Unrecorded Excess Earnings, Related Carrying Costs and Other | 52 |
| Settlement Reduction | (77) |
| Reduction for the ADITC and EDFIT Benefits | (61) |
| Approved Securitizable Amount | 1,697 |
| Unrecorded Securitization Bond Issuance Costs | 23 |
| Amount to be Securitized | \$ 1,720 |

Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes

In TCC's true-up and securitization orders, the PUCT reduced net stranded generation plant costs and the amount to be securitized by \$51 million related to the present value of ADITC and by \$10 million related to EDFIT associated with TCC's generating assets. TCC testified that the sharing of these tax benefits with customers might be a violation of the Internal Revenue Code's normalization provisions.

TCC filed a request for a private letter ruling from the IRS in June 2005 to determine whether the PUCT's action would result in a normalization violation. The IRS issued its private letter ruling on May 9, 2006 and decided against the PUCT treatment and determined the PUCT's flowthrough to customers of the ADITC and EDFIT benefits would result in a normalization violation. TCC informed the PUCT on May 10, 2006 of the adverse ruling, however, the PUCT did not change its order on rehearing. TCC filed an appeal as noted earlier. As discussed in the "CTC Proceeding for Other True-up Items" section of this note, TCC proposed to defer the refunding of the ADITC and EDFIT in the securitization through its CTC filing until this normalization issue is resolved upon the IRS issuance of final normalization regulations.

If a normalization violation occurs, it could result in the repayment of TCC's ADITC on all property, including transmission and distribution, which approximates \$105 million as of June 30, 2006 and also a loss of claiming accelerated tax depreciation in future tax returns. Tax counsel has advised management that a normalization violation should not occur until all remedies under law have been exhausted and the tax benefits are returned to ratepayers under a nonappealable order. Management intends to continue its efforts to avoid a normalization violation that would adversely affect future results of operations and cash flows.

CTC Proceeding for Other True-up Items

In June 2006, TCC filed to implement a negative CTC (a rate reduction) for its net other true-up items over eight years. TCC will incur carrying costs on the net negative other true-up regulatory liability balances until fully refunded. The principal components of the CTC refund liability are an over-recovered fuel balance, the retail clawback and the ADFIT benefit related to TCC's stranded generation cost, offset by a positive wholesale capacity auction true-up regulatory asset balance.

The differences between the components of TCC's Recorded Net Regulatory Liabilities for Other True-up Items as of June 30, 2006 and its CTC gross refund proposal are detailed below:

| | (in millions) |
|--|---------------|
| Wholesale Capacity Auction True-up | \$ 61 |
| Carrying Costs on Wholesale Capacity Auction True-up | 28 |
| Retail Clawback including Carrying Costs | (63) |
| Deferred Over-recovered Fuel Balance | (181) |

| | |
|--|-----------------|
| Retrospective ADFIT Benefit | (70) |
| Other | (4) |
| Recorded Net Regulatory Liabilities - Other True-up Items | (229) |
| Unrecorded Prospective ADFIT Benefit | (240) |
| Unrecorded Estimated July 2006 - August 2006 Carrying Costs | (6) |
| Gross CTC Refund Proposed | (475) |
| FERC Jurisdictional Fuel Refund Deferral | 16 |
| ADITC and EDFIT Benefit Refund Deferral | 97 |
| Net CTC Refund Proposed, After Deferrals | (362) |
| Rate Case Expense Surcharge | 7 |
| Net Refund Proposed, After Deferrals and Expenses | \$ (355) |

TCC requested that a portion of the refund be deferred, pending the outcome of two contingent federal matters related to the refund of \$16 million of FERC jurisdictional fuel over-recoveries (discussed below) and \$97 million related to potential tax normalization violation matters related to the refund of ADITC and EDFIT benefits discussed above. Although TCC proposed to refund the \$355 million over eight years, certain intervenors have supported accelerated refunds. Management cannot predict the outcome of this filing. If the two contingent federal matters are resolved unfavorably, TCC will refund the \$16 million and the \$97 million plus carrying costs.

Fuel Balance Recoveries

In September 2005, the Federal District Court, Western District of Texas, issued an order precluding the PUCT from enforcing its ruling in the TNC fuel proceeding regarding the PUCT's reallocation of off-system sales margins. TCC has a similar appeal outstanding and believes that the same ruling should result. The favorable Federal District Court order, if upheld on appeal, could result in reductions to the over-recovered fuel principal balances of \$8 million for TNC and \$14 million (\$16 million with carrying costs) for TCC. The PUCT appealed the Federal Court decision to the United States Court of Appeals for the Fifth Circuit. If the PUCT is unsuccessful in the federal court system, it may file a complaint at the FERC to address the allocation issue. We are unable to predict if the Federal District Court's decision will be upheld or whether the PUCT will file a complaint at the FERC. Pending further clarification, TCC and TNC have not reversed their related provisions for fuel over-recovery. If the PUCT or another party were to file a complaint at the FERC and is successful, it could result in an adverse effect on results of operations and cash flows for the AEP East companies as an unfavorable FERC ruling may result in a reallocation of off-system sales margins from AEP East companies to AEP West companies. If the adjustments were applied retroactively, the AEP East companies may be unable to recover the amounts from their customers due to past frozen rates, past inactive fuel clauses and fuel clauses that do not include off-system sales credits.

Carrying Costs on Net True-up Regulatory Assets Impacting Securitization and CTC Proceedings

In TCC's True-up Proceeding, the PUCT allowed TCC to recover carrying costs at an 11.79% overall pretax weighted average cost of capital rate from its unbundled cost of service rate proceeding. The recorded embedded debt component of this carrying cost rate is 8.12%. Through June 30, 2006, TCC recorded \$375 million of debt-related carrying costs on stranded generation plant costs impacting the securitization proceeding. TCC will continue to accrue debt-related carrying cost income until its net true-up regulatory asset is either securitized or fully recovered. Equity carrying costs of \$217 million related to amounts securitized will be recognized in income as collected. The negative carrying cost, both debt and equity, on the net CTC refund is being fully recognized in income, and totals \$52 million through June 2006.

In June 2006, the PUCT adopted a proposed rule that prospectively changes the carrying cost applied to TCC's CTC refund balance. TCC anticipates that the rule change will reduce the carrying cost that TCC will pay on its CTC balance from 11.79% to 7.47%. TCC anticipates that the change will reduce its annual refund by approximately \$8 million. The rule provides for adjustments to the carrying cost rate during subsequent rate case proceedings.

Summary

Our recorded securitizable true-up regulatory asset at June 30, 2006 of \$1.5 billion, net of the recorded net regulatory liabilities for other true-up items of \$229 million, reflects the PUCT's orders in TCC's True-up Proceeding and its securitization proceeding. Barring any future disallowances to TCC's net recoverable true-up regulatory asset in any subsequent proceedings or Court rulings, TCC expects to amortize its total securitizable true-up regulatory asset commensurate with recovery over 14 years. If we determine as a result of future PUCT orders or appeal court rulings that it is probable TCC cannot recover a portion of its recorded net true-up regulatory asset and we are able to estimate the amount of a resultant impairment, we would record a provision for such amount which would have an adverse effect on future results of operations, cash flows and possibly financial condition. TCC is appealing the PUCT orders seeking relief in both state and federal court where it believes the PUCT's rulings are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law. Municipal customers and other intervenors are also appealing the same PUCT orders seeking to further reduce TCC's true-up recoveries.

Although TCC believes it has meritorious arguments, management cannot predict the ultimate outcome of any future proceedings or court appeals. If TCC succeeds in its future appeals, it could have a material favorable effect on future results of operations, cash flows and financial condition. If municipal customers and other intervenors succeed in their expected appeals, or if the PUCT does not approve TCC's CTC filing as filed and as a result causes a normalization violation, it could have a material adverse effect on future results of operations, cash flows and financial condition.

Texas Restructuring - SPP

In June 2006, the PUCT adopted a rule delaying customer choice in the SPP area of Texas until no sooner than January 1, 2011. SWEPCo and a small portion of TNC's business operate in SPP. Approximately 3% of TNC's operations are located in the SPP territory, with \$13 million in net assets. A petition was filed in May 2006, requesting approval to transfer Mutual Energy SWEPCO L.P.'s (a subsidiary of AEP C&I Company, LLC) and TNC's customers, facilities and certificated service located in the SPP area to SWEPCo. If this petition is successful, SWEPCo will be our only remaining subsidiary affected by the delay in the SPP area.

OHIO RESTRUCTURING

Rate Stabilization Plans

In January 2005, the PUCO approved Rate Stabilization Plans (RSPs) for CSPCo and OPCo (the Ohio companies). The approved plans in each of 2006, 2007 and 2008 provide, among other things, for CSPCo and OPCo to raise their generation rates by 3% and 7%, respectively, and provide for possible additional annual generation rate increases of up to an average of 4% per year based on supporting the request for additional revenues for specified costs. CSPCo's potential for the additional annual 4% generation rate increases is diminished by approximately three-quarters in 2006 and to a lesser extent in 2007 and 2008 due to the power acquisition rider approved by the PUCO in the Monongahela Power service territory acquisition proceeding and the recovery of pre-construction costs for the IGCC plant (see "IGCC Plant" section of this note below). OPCo's potential for the additional annual 4% generation rate increases is diminished in 2006 by approximately one-quarter and to a lesser extent in 2007 due to the recovery of pre-construction costs for the IGCC plant. The RSPs also provide that the Ohio companies can recover in 2006, 2007 and 2008 estimated 2004 and 2005 environmental carrying costs and PJM-related administrative costs and congestion costs net of financial transmission rights (FTR) revenue related to their obligation as the Provider of Last Resort (POLR) in Ohio's customer choice program. Pretax earnings increased by \$8 million and \$16 million for CSPCo and \$17 million and \$38 million for OPCo in the second quarter and first six months of 2006, respectively, from the RSP rate increases net of amortization of RSP regulatory assets. These increases also included the recognition of equity carrying costs. As of June 30, 2006, unrecognized equity carrying costs from 2004 and 2005, which are recognized over the three-year RSP period, totaled \$36 million. As of June 30, 2006, the unamortized RSP regulatory assets to be

recovered through December 31, 2008 were \$47 million.

In the second quarter of 2005, the Ohio Consumers' Counsel filed an appeal to the Ohio Supreme Court that challenged the RSPs and also argued that there was no POLR obligation in Ohio and, therefore, CSPCo and OPCo are not entitled to recover any POLR charges. In Dayton Power & Light Company's proceeding, the Ohio Supreme Court concluded that there is a POLR obligation in Ohio, supporting the Ohio companies' position that they can recover a POLR charge. In an appeal concerning the First Energy companies' RSP, the Ohio Supreme Court held that the PUCO's decision to eliminate the offer to customers of a price determined through competitive bids was unlawful. In July 2006, the Ohio Supreme Court vacated the PUCO's RSP order for the Ohio companies, which did not include a competitive bid process, and remanded the case to the PUCO for further proceedings, not inconsistent with the decision in the appeal of the First Energy companies' RSP. The PUCO has not yet acted on the remand of our RSP orders. In late July 2006, the PUCO acted on the First Energy companies' remand case ordering them to file a plan within 45 days to provide an option for customer participation in the electric market through competitive bids or other reasonable means and also held that the RSP shall remain effective.

In the Ohio companies' case, the Ohio Supreme Court did not address any other issues that had been raised on appeal, stating that its decision does not preclude the Ohio Consumers' Counsel from raising those issues in a future appeal. If the PUCO were to revise the Ohio companies' RSP to include a competitive bid process, the Ohio companies believe that the remainder of the original RSP order should remain in place. However, if on remand the PUCO were to modify other aspects of the RSP order, it could have a material effect on future results of operations and cash flows. Pending action by the PUCO on the remand, the Ohio companies' rates and the recovery of the RSP regulatory assets will continue. Management believes that the RSP regulatory assets remain probable of recovery.

IGCC Plant

In March 2005, the Ohio companies 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 proposed cost recovery associated with the IGCC plant in three phases: Phase 1, recovery of \$24 million in pre-construction costs during 2006; Phase 2, recovery of construction-financing costs; and Phase 3, recovery, or refund, in distribution rates of any difference between the market-based standard service offer price for generation and the cost of operating and maintaining the plant, including a return on and return of the projected \$1.2 billion cost of the plant along with fuel, consumables and replacement power costs. The proposed recoveries in Phases 1 and 2 would be applied against the 4% limit on additional generation rate increases the Ohio companies could request in 2006, 2007 and 2008 under their RSPs. As of June 30, 2006, the Ohio companies deferred \$13 million of pre-construction IGCC costs.

In April 2006, the PUCO issued an order authorizing the Ohio companies to implement Phase 1 of the cost recovery proposal. The PUCO deferred ruling on Phases 2 and 3 cost recovery until further hearings are held. No date for a further hearing has been set.

In June 2006, the PUCO approved a tariff to recover Phase 1 pre-construction costs over a twelve-month period effective July 1, 2006. In that order the PUCO indicated if the Ohio companies have not commenced continuous construction of the IGCC plant within five years of the order, all charges collected for pre-construction costs, which are assignable to other jurisdictions, must be refunded to Ohio ratepayers with interest.

In June 2006, the Industrial Energy Users - Ohio, an intervenor in the PUCO proceeding, filed a Complaint for Writ of Prohibition at the Ohio Supreme Court to prohibit the use of the PUCO's authorization by the Ohio companies to enforce the collection of the Phase 1 rates and to prohibit the PUCO from further entertaining any increase in rates for the IGCC project. The Ohio companies filed motions to dismiss the complaint with the Ohio Supreme Court. The Ohio companies believe that the PUCO's authorization to begin collection of Phase 1 rates is lawful and that the PUCO has the authority to consider the remaining rate recovery phases associated with the IGCC project. The Ohio companies, however, cannot predict the ultimate outcome of this proceeding or of any appeal of the PUCO's April

2006 order. If the Ohio companies were prohibited from collecting the Phase 1 rates or if the PUCO's order is appealed and found to be unlawful, their future results of operations and cash flows would be adversely affected.

Transmission Rate Filing

In February 2006, in accordance with their RSPs, the Ohio companies filed a request with the PUCO for a two-step increase in their transmission rates. In the filing, the first increase would be effective April 1, 2006 to reflect their share of the loss of SECA revenues and the second increase would be effective August 1, 2006 to recover their share of the cost of the new Wyoming-Jacksons Ferry transmission line. In May 2006, the PUCO issued an order approving the two-step increase in transmission rates with an over/under recovery mechanism effective April 1, 2006. In addition, the order provided for the deferral for future recovery of unrecovered transmission costs resulting from the loss of SECA revenues back to April 1, 2006. The new tariffs were filed with the PUCO and implemented in June 2006. We anticipate the order will result in increased revenues for CSPCo and OPCo of \$27 million and \$36 million, respectively, in 2006 and \$44 million and \$59 million, respectively, in 2007.

Storm Cost Recovery Filing

In March 2006, the Ohio companies filed an application with the PUCO to implement tariff riders to recover a portion of previously expensed incremental costs of restoring service disrupted by severe winter storms in December 2004 and January 2005. CSPCo and OPCo each requested recovery of approximately \$12 million of such costs. A decision is expected in the third quarter of 2006.

PUCO Staff Report on Service Reliability

In December 2003, the Ohio companies entered into a stipulation agreement regarding distribution service reliability. The stipulation agreement covered the years 2004 and 2005 and, among other features, established certain distribution service reliability measures that the Ohio companies were to meet. In April 2006, the staff of the PUCO submitted a commission-ordered investigative report on the Ohio companies' compliance with the stipulation agreement. In the report, the staff asserted that the Ohio companies failed to fulfill all the terms of the stipulation agreement. The staff recommended various consequences for the PUCO's consideration, including the potential for civil forfeitures, monthly payments until the terms of the stipulation agreement have been met and/or providing credits to customers. The staff also suggested that the PUCO could explore possible improvements in the Ohio companies' management of the reliability process. Finally, the staff recommended that the Ohio companies file, in a companion docket, a comprehensive plan to improve their system reliability. The PUCO ordered the Ohio companies to respond to the staff's recommendations concerning consequences by May 23, 2006.

The Ohio companies responded on a timely basis explaining why they believed that they had substantially met the requirements of the stipulation agreement and offering to spend an additional \$5 million on reliability without recovery. In July 2006, the PUCO directed the Ohio companies to earmark \$10 million for future measures to improve service reliability. The Ohio companies will not be permitted to recover any of that amount from customers. The PUCO further indicated that it will determine where and how the \$10 million will best be applied. In a separate docket, the PUCO directed the Ohio companies to submit a plan to enhance service reliability no later than October 6, 2006. The PUCO indicated that it will set a procedural schedule in the future to consider the Ohio companies' plan.

Customer Choice Deferrals

As provided in stipulation agreements approved by the PUCO in 2000, the Ohio companies defer customer choice implementation costs and related carrying costs in excess of \$20 million each. The agreements provide for the deferral of these costs as regulatory assets until the next distribution base rate cases. Through June 30, 2006, we incurred \$95 million of such costs and, accordingly, we deferred \$47 million of such costs for probable future recovery in distribution rates. We have not recorded \$8 million of equity carrying costs, which are not recognized until collected.

Pursuant to the RSPs, recovery of these amounts is subject to PUCO review and deferred until the next distribution rate filing to change rates after December 31, 2008. We believe that the deferred customer choice implementation costs were prudently incurred to implement customer choice in Ohio and should be recoverable in future distribution rates. If the PUCO determines that any of the deferred costs are unrecoverable, it would have an adverse impact on future results of operations and cash flows.

5. COMMITMENTS AND CONTINGENCIES

As discussed in the Commitments and Contingencies note within our 2005 Annual Report, we continue to be involved in various legal matters. The 2005 Annual Report should be read in conjunction with this report in order to understand the other material nuclear and operational matters without significant changes since our disclosure in the 2005 Annual Report. See disclosure below for significant matters and changes in status subsequent to the disclosure made in our 2005 Annual Report.

ENVIRONMENTAL

Federal EPA Complaint and Notice of Violation

The Federal EPA and a number of states alleged that APCo, CSPCo, I&M, OPCo and other nonaffiliated utilities, including the Tennessee Valley Authority, Alabama Power Company, Cincinnati Gas & Electric Company, Ohio Edison Company, Southern Indiana Gas & Electric Company, Illinois Power Company, Tampa Electric Company, Virginia Electric Power Company and Duke Energy, modified certain units at coal-fired generating plants in violation of the NSR 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. A bench trial on the liability issues was held during July 2005. Briefing has concluded. In June 2006, the judge stayed the liability decision pending the issuance of a decision by the U.S. Supreme Court in the Duke Energy case. A bench trial on remedy issues, if necessary, is scheduled to begin four months after the U.S. Supreme Court decision is issued.

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 CAA authorizes civil penalties of up to \$27,500 (\$32,500 after March 15, 2004) per day per violation at each generating unit. In 2001, the District Court ruled claims for civil penalties based on activities that occurred more than five years before the filing date of the complaints cannot be imposed. There is no time limit on claims for injunctive relief.

The Federal EPA and eight northeastern states each filed an additional complaint containing additional allegations against the Amos and Conesville plants. APCo and CSPCo filed an answer to the northeastern states' complaint and the Federal EPA's complaint, denying the allegations and stating their defenses. Cases are also pending that could affect CSPCo's share of jointly-owned units at Beckjord, Zimmer and Stuart stations. Similar cases have been filed against other nonaffiliated utilities, including Allegheny Energy, Eastern Kentucky Electric Cooperative, Public Service Enterprise Group, Santee Cooper, Wisconsin Electric Power Company, Mirant, NRG Energy and Niagara Mohawk. Several of these cases were resolved through consent decrees.

Courts have reached different conclusions regarding whether the activities at issue in these cases are routine maintenance, repair, or replacement, and therefore are excluded from NSR. Similarly, courts have reached different results regarding whether the activities at issue increased emissions from the power plants. Appeals on these and other issues were filed in certain appellate courts, including a petition to appeal to the U.S. Supreme Court that was granted in one case. The Federal EPA issued a final rule that would exclude activities similar to those challenged in these

cases from NSR as “routine replacements.” In March 2006, the Court of Appeals for the District of Columbia Circuit issued a decision vacating the rule. The Federal EPA filed a petition for rehearing in that case, which the Court denied. The Federal EPA also recently proposed a rule that would define “emissions increases” in a way that would exclude most of the challenged activities from NSR.

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, we believe we can recover any capital and operating costs of additional pollution control equipment that may be required through regulated rates and market prices of electricity. If we are unable to recover such costs or if material penalties are imposed, it would adversely affect future results of operations, cash flows and possibly financial condition.

SWEP Co Notice of Enforcement and Notice of Citizen Suit

In July 2004, two special interest groups, Sierra Club and Public Citizen, issued a notice of intent to commence a citizen suit under the CAA for alleged violations of various permit conditions in permits issued to several SWEP Co generating plants. In March 2005, the special interest groups filed a complaint in Federal District Court for the Eastern District of Texas alleging violations of the CAA at the Welsh Plant. SWEP Co filed a response to the complaint in May 2005. Other preliminary motions have been filed and are pending before the Court.

In July 2004, the Texas Commission on Environmental Quality (TCEQ) issued a Notice of Enforcement to SWEP Co relating to the Welsh Plant containing a summary of findings resulting from a compliance investigation at the plant. In April 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 approximately \$228 thousand against SWEP Co based on alleged violations of certain representations regarding heat input in SWEP Co’s permit application and the violations of certain recordkeeping and reporting requirements. SWEP Co responded to the preliminary report and petition in May 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. SWEP Co had previously requested a permit alteration to remove the reference to a specific heat input value for each Welsh unit.

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, financial condition or cash flows.

Carbon Dioxide Public Nuisance Claims

In July 2004, attorneys general from eight states and the corporation counsel for the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. That same day, the Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint in the same court against the same defendants. The actions alleged that CO₂ emissions from the defendants’ power plants constitute a public nuisance under federal common law due to impacts associated with global warming and sought injunctive relief in the form of specific emission reduction commitments from the defendants. In September 2004, the defendants, including AEP and AEPSC, filed a motion to dismiss the lawsuits. In September 2005, the lawsuits were dismissed. The trial court’s dismissal was appealed to the Second Circuit Court of Appeals. Briefing and oral argument have been completed. We believe the actions are without merit and intend to defend vigorously against the claims.

Ontario Litigation

In June 2005, we and nineteen nonaffiliated utilities were named as defendants in a lawsuit filed in the Superior Court of Justice in Ontario, Canada. We have not been served with the lawsuit. The time limit for serving the defendants

expired, but the case has not been dismissed. The defendants are alleged to own or operate coal-fired electric generating stations in various states that, through negligence in design, management, maintenance and operation, emitted NO_x, SO₂ and particulate matter that harmed the residents of Ontario. The lawsuit seeks class action designation and damages of approximately \$49 billion, with continuing damages of \$4 billion annually. The lawsuit also seeks \$1 billion in punitive damages. We believe we have meritorious defenses to this action and intend to defend vigorously against it.

OPERATIONAL

Power Generation Facility and TEM Litigation

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

Juniper is a nonaffiliated limited partnership, formed to construct or otherwise acquire real and personal property for lease to third parties, to manage financial assets and to undertake other activities related to asset financing. Juniper arranged to finance the Facility. The Facility is collateral for Juniper’s debt financing. Due to the treatment of the Facility as a financing of an owned asset, we recognized all of Juniper’s funded obligations as a liability. Upon expiration of the lease, our actual cash obligation could range from \$0 to \$415 million based on the fair value of the assets at that time. However, if we default under the Juniper lease, our maximum cash payment could be as much as \$525 million. Because we report Juniper’s funded obligations totaling \$525 million related to the Facility on our Condensed Consolidated Balance Sheets, the fair value of the liability for our guarantee (the \$415 million payment discussed above) is not separately reported.

Dow uses a portion of the energy produced by the Facility and sells the excess energy. OPCo 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 (approximately 270 MW). OPCo sells the purchased energy at market prices in the Entergy sub-region of the Southeastern Electric Reliability Council market.

OPCo agreed to sell up to approximately 800 MW of energy to 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 alleged that TEM breached the PPA, and we sought a determination of our rights under the PPA. TEM alleged that the PPA never became enforceable, or alternatively, that the PPA was terminated as the result of AEP’s breaches. The corporate parent of TEM (SUEZ-TRACTEBEL S.A.) provided a limited guaranty.

In April 2004, OPCo gave notice to TEM that OPCo (a) was suspending performance of its obligations under the PPA; (b) would seek a declaration from the District Court that the PPA was terminated; and (c) would pursue TEM and SUEZ-TRACTEBEL S.A. under the guaranty, seeking damages and the full termination payment value of the PPA.

A bench trial was conducted in March and April 2005. In August 2005, a federal judge ruled that TEM breached the contract and awarded us damages of \$123 million plus prejudgment interest. In August 2005, both parties filed motions with the trial court seeking reconsideration of the judgment. We asked the court to modify the judgment to (a)

award a termination payment to us under the terms of the PPA; (b) grant our attorneys' fees; and (c) render judgment against SUEZ-TRACTEBEL S.A. on the guaranty. TEM sought reduction of the damages awarded by the court for replacement electric power products made available by OPCo under the PPA. In January 2006, the trial judge granted our motion for reconsideration concerning TEM's parent guaranty and increased our judgment against TEM to \$173 million plus prejudgment interest, and denied the remaining motions for reconsideration. In March 2006, the trial judge amended the January 2006 order eliminating the additional \$50 million damage award.

In September 2005, TEM posted a letter of credit for \$142 million as security pending appeal of the judgment. Both parties have filed Notices of Appeal with the United States Court of Appeals for the Second Circuit. If the PPA is deemed terminated or found unenforceable by the court ultimately deciding the case, 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 the claimed termination value damages from TEM. Management continues to review all options associated with the Facility investment in order to minimize any long-term negative results.

Enron Bankruptcy

In connection with our 2001 acquisition of HPL, we entered into an agreement with BAM Lease Company, which granted 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 released HPL from all prior and future liabilities and obligations in connection with the financing arrangement.

After the Enron bankruptcy the BOA Syndicate informed HPL 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 Texas state court 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. The state court of appeals heard oral argument on the appeal in June 2006. 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. In April 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 objected to Enron's attempted rejection of these agreements and filed an adversary proceeding contesting Enron's right to reject these agreements.

In June 2006, we started mediation with BOA and Enron concerning these gas disputes.

In 2005, we sold our interest in HPL. We indemnified the buyer of HPL against any damages resulting from the BOA litigation up to the purchase price. The determination of the gain on sale and the recognition of the gain are dependent on the ultimate resolution of the BOA dispute and the costs, if any, associated with the resolution of this matter (see Note 8).

Although management is unable to predict the outcome of the remaining lawsuits, it is possible that their resolution could have an adverse impact on our results of operations, cash flows and financial condition.

Shareholder Lawsuits

In the fourth quarter of 2002 and the first quarter of 2003, three putative class action lawsuits were filed against AEP, certain executives and AEP's Employee Retirement Income Security Act (ERISA) Plan Administrator alleging violations of ERISA in the selection of AEP stock as an investment alternative and in the allocation of assets to AEP stock. The ERISA actions were pending in Federal District Court, Columbus, Ohio. In July 2006, the Court entered judgment denying plaintiff's motion for class certification and dismissing all claims without prejudice.

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 was dismissed from the case. A number of similar cases were filed in California. In addition, a number of other 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 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 and in December 2005, the judge dismissed two additional cases on the same ground. Plaintiffs in these cases appealed the decisions. We will continue to defend vigorously each case where an AEP company is a defendant.

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. These cases were consolidated. In January 2004, plaintiffs filed an amended consolidated complaint. The defendants filed a motion to dismiss the complaint which the Court denied. In October 2005, the Court granted the plaintiffs motion for class certification. The defendants filed a petition for leave to appeal this decision. We intend to continue to defend vigorously against these claims.

FERC Long-term Contracts

In 2002, the FERC held a hearing related to a complaint filed by Nevada Power Company and Sierra Pacific Power Company (the Nevada utilities). The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were "high-priced." The complaint alleged that we sold power at unjust and unreasonable prices. In December 2002, a FERC ALJ ruled in our favor and dismissed the complaint filed by the Nevada utilities. In 2001, the Nevada utilities filed complaints asserting that the prices for power supplied under those contracts should be lowered because the market for power was allegedly dysfunctional at the time such contracts were executed. The ALJ rejected the Nevada utilities' complaint, held that the markets for future delivery were not dysfunctional, and that the Nevada utilities failed to demonstrate that the public interest required changes be made to the contracts. In June 2003, the FERC issued an order affirming the ALJ's decision. The Nevada utilities' request for a rehearing was denied. The Nevada utilities' appeal of the FERC order is pending before the U.S. Court of Appeals for the Ninth Circuit. Management is unable to predict the outcome of this proceeding and its impact on future results of operations and cash flows.

6. GUARANTEES

There are certain immaterial liabilities recorded for guarantees in accordance with FASB Interpretation No. 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." There is no collateral held in relation to any guarantees in excess of our ownership percentages. In the event any guarantee is drawn, there is no recourse to third parties unless specified below.

LETTERS OF CREDIT

We enter into standby letters of credit (LOCs) with third parties. These LOCs cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. As the parent company, we issued all of these LOCs in our ordinary course of business on behalf of our subsidiaries. At June 30, 2006, the maximum future payments for all the LOCs are approximately \$31 million with maturities ranging from July 2006 to March 2007.

GUARANTEES OF THIRD-PARTY OBLIGATIONS

SWEPCo

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo agreed, under certain conditions, to assume the capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). If Sabine defaults under any of these agreements, SWEPCo's total future maximum payment exposure is approximately \$58 million with maturity dates ranging from July 2006 to February 2012.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation in the amount of approximately \$85 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine. This guarantee ends upon depletion of reserves and final reclamation is completed. At June 30, 2006, it is estimated the reserves will be depleted in 2029 with final reclamation completed by 2036. The cost for final reclamation during the period 2029 through 2036 is estimated at approximately \$39 million.

INDEMNIFICATIONS AND OTHER GUARANTEES

Contracts

We enter into several types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these

agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price. Prior to June 30, 2006, we entered into several sale agreements. The status of certain sales agreements is discussed in the “Dispositions” section of Note 8. These sale agreements include indemnifications with a maximum exposure related to the collective purchase price, which is approximately \$2.2 billion (approximately \$1 billion relates to the BOA litigation, see “Enron Bankruptcy” section of Note 5). There are no material liabilities recorded for any indemnifications.

Master Operating Lease

We lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed receipt of up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, we are committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At June 30, 2006, the maximum potential loss for these lease agreements was approximately \$54 million (\$35 million, net of tax) assuming the fair market value of the equipment is zero at the end of the lease term.

Railcar Lease

In June 2003, we entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease has an initial term of five years.

At the end of each lease term, we may (a) renew for another five-year term, not to exceed a total of twenty years, (b) purchase the railcars for the purchase price amount specified in the lease, projected at the lease inception to be the then fair market value, or (c) return the railcars and arrange a third party sale (return-and-sale option). The lease is accounted for as an operating lease. We intend to renew the lease for the full twenty years.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under the return-and-sale option discussed above will equal at least the lessee obligation amount specified in the lease, which declines over the lease term from approximately 86% to 77% of the projected fair market value of the equipment. At June 30, 2006, the maximum potential loss was approximately \$31 million (\$20 million, net of tax) assuming the fair market value of the equipment is zero at the end of the current lease term. We have other rail car lease arrangements that do not utilize this type of structure.

7. COMPANY-WIDE STAFFING AND BUDGET REVIEW

As a result of a company-wide staffing and budget review in the second quarter of 2005, we identified approximately 500 positions for elimination. Pretax severance benefits expense of \$24 million was recorded (primarily in Maintenance and Other Operation within the Utility Operations segment) in the second quarter of 2005.

The following table shows the accrual as of December 31, 2005 (reflected primarily in Current Liabilities - Other) and the activity during the first six months of 2006, which eliminated the accrual as of June 30, 2006:

| | Amount (in millions) |
|------------------------------|---------------------------------|
| Accrual at December 31, 2005 | \$ 12 |
| Less: Total Payments | 8 |
| Less: Accrual Adjustments | 4 |
| Accrual at June 30, 2006 | \$ - |

The accrual adjustments were recorded primarily in Maintenance and Other Operation on our Condensed Consolidated Statements of Operations.

8. DISPOSITIONS, DISCONTINUED OPERATIONS AND ASSETS HELD FOR SALE

DISPOSITIONS

2006

Compresion Bajio S de R.L. de C.V. (Investments - Other segment)

In January 2002, we acquired a 50% interest in Compresion Bajio S de R.L. de C.V. (Bajio), a 600-MW power plant in Mexico. We received an indicative offer for Bajio in September 2005. The sale was completed in February 2006 for approximately \$29 million with no effect on our 2006 results of operations.

2005

Houston Pipe Line Company LP (HPL) (Investments - Gas Operations segment)

During 2005, we sold our interest in HPL, 30 billion cubic feet (BCF) of working gas and working capital for approximately \$1 billion, subject to a working capital and inventory true-up adjustment. Although the assets were legally transferred, it is not possible to determine all costs associated with the transfer until the Bank of America (BOA) litigation is resolved. Accordingly, we recorded the excess of the sales price over the carrying cost of the net assets transferred as a deferred gain of \$379 million as of June 30, 2006 and December 31, 2005, which is reflected in Deferred Credits and Other on our accompanying Condensed Consolidated Balance Sheets. We provided an indemnity in an amount up to the purchase price to the purchaser for damages, if any, arising from litigation with BOA and a potential resulting inability to use the cushion gas (see "Enron Bankruptcy" section of Note 5). The HPL operations did not meet the criteria to be shown as discontinued operations due to continuing involvement associated with various contractual obligations. Significant continuing involvement includes cash flows from long-term gas contracts with the buyer through 2008 and the cushion gas arrangement. In addition, we continue to hold forward gas contracts not sold with the gas pipeline and storage assets.

Texas REPs (Utility Operations segment)

In December 2002, we sold two of our Texas REPs to Centrica, a UK-based provider of retail energy. The sales price was \$146 million plus certain other payments including an earnings-sharing mechanism (ESM) for AEP and Centrica to share in the earnings of the sold business for the years 2003 through 2006. The method of calculating the annual earnings-sharing amount was included in the Purchase and Sales Agreement and was amended through a series of agreements that AEP and Centrica entered in March 2005. Also in March 2005, we received payments related to the ESM of \$45 million and \$70 million for 2003 and 2004, respectively, resulting in a pretax gain of \$112 million in 2005. In March 2006, we received a payment of \$70 million related to the ESM for 2005. The ESM payment for 2006 is contingent on Centrica's future operating results and is capped at \$20 million. The payments are reflected in Gain/Loss on Disposition of Assets, Net on our accompanying Condensed Consolidated Statements of Operations.

DISCONTINUED OPERATIONS

Certain of our operations were determined to be discontinued operations and have been classified as such for all periods presented. Results of operations of these businesses have been classified as shown in the following table (in millions):

Three Months ended June 30, 2006 and 2005:

| | SEEBOARD | | | |
|---------------------------|-----------------|------|----------------------------|--------------|
| | (a) | | U.K. Generation (b) | Total |
| 2006 Revenue | \$ - | \$ - | \$ - | \$ - |
| 2006 Pretax Income | - | | 4 | 4 |
| 2006 Earnings, Net of Tax | - | | 3 | 3 |
| 2005 Revenue | \$ - | \$ - | \$ - | \$ - |
| 2005 Pretax Income | - | | - | - |
| 2005 Earnings, Net of Tax | 3 | | - | 3 |

Six Months ended June 30, 2006 and 2005:

| | SEEBOARD | | | |
|----------------------------------|-----------------|------|---------------------------|--------------|
| | (a) | | U.K. Generation(c) | Total |
| 2006 Revenue | \$ - | \$ - | \$ - | \$ - |
| 2006 Pretax Income | - | | 9 | 9 |
| 2006 Earnings, Net of Tax | - | | 6 | 6 |
| 2005 Revenue (Expense) | \$ - | \$ - | (8) | \$ (8) |
| 2005 Pretax Loss | - | | (8) | (8) |
| 2005 Earnings (Loss), Net of Tax | 9 | | (5) | 4 |

- (a) The amounts relate to purchase price true-up adjustments and tax adjustments from the sale of SEEBOARD.
- (b) The amounts relate to tax adjustments from the sale.
- (c) The 2006 amounts relate to a release of accrued liabilities for the London office lease and tax adjustments from the sale. Amounts in 2005 relate to purchase price true-up adjustments and tax adjustments from the sale.

There were no cash flows used for or provided by operating, investing or financing activities related to our discontinued operations for the six months ended June 30, 2006 and 2005.

ASSETS HELD FOR SALE***Texas Plants - Oklaunion Power Station (Utility Operations segment)***

In January 2004, we signed an agreement to sell TCC's 7.81% share of Oklaunion Power Station for approximately \$43 million (subject to closing adjustments) to Golden Spread Electric Cooperative, Inc. (Golden Spread), subject to a right of first refusal by the Oklahoma Municipal Power Authority and the Public Utilities Board of the City of Brownsfield (the nonaffiliated co-owners). By May 2004, we received notice from the nonaffiliated co-owners of the Oklaunion Power Station, announcing their decision to exercise their right of first refusal with terms similar to the original agreement. In June 2004 and September 2004, we entered into sales agreements with both of the nonaffiliated co-owners for the sale of TCC's 7.81% ownership of the Oklaunion Power Station. These agreements were challenged in State District Court in Dallas County by Golden Spread. Golden Spread alleges that the Public Utilities Board of the City of Brownsfield exceeded its legal authority and that the Oklahoma Municipal Power Authority did not exercise its right of first refusal in a timely manner. Golden Spread requested that the court declare the nonaffiliated co-owners' exercise of their rights of first refusal void. The court entered a judgment in favor of Golden Spread on October 10, 2005. TCC and the nonaffiliated co-owners filed an appeal to the Court of Appeals for the Fifth District at Dallas. On May 18, 2006, the Court of Appeals for the Fifth District at Dallas reversed the trial court's judgment in favor of Golden Spread and held that the City of Brownsville properly exercised its right of first refusal to acquire TCC's share of Oklaunion. Golden Spread requested a rehearing in the matter, and its petition was denied. We cannot predict when these issues will be resolved. We do not expect the sale to have a significant effect on our future results

of operations. TCC's assets related to the Oklaunion Power Station are classified as Assets Held for Sale on our Condensed Consolidated Balance Sheets at June 30, 2006 and December 31, 2005. The plant does not meet the "component-of-an-entity" criteria because it does not have cash flows that can be clearly distinguished operationally. The plant also does not meet the "component-of-an-entity" criteria for financial reporting purposes because it does not operate individually, but rather as a part of the AEP System, which includes all of the generation facilities owned by our Registrant Subsidiaries.

Assets Held for Sale at June 30, 2006 and December 31, 2005 are as follows:

| Texas Plants | June 30, 2006 | December 31, 2005 |
|------------------------------------|----------------------|----------------------|
| Assets: | (in millions) | |
| Other Current Assets | \$ 2 | \$ 1 |
| Property, Plant and Equipment, Net | 44 | 43 |
| Total Assets Held for Sale | \$ 46 | \$ 44 |

9. BENEFIT PLANS

Components of Net Periodic Benefit Cost

The following table provides the components of our net periodic benefit cost for the following plans for the three and six months ended June 30, 2006 and 2005:

| Three Months Ended June 30, 2006 and 2005: | Pension Plans | | Other Postretirement Benefit Plans | |
|---|---------------|--------------|---------------------------------------|--------------|
| | 2006 | 2005 | 2006 | 2005 |
| | (in millions) | | | |
| Service Cost | \$ 24 | \$ 23 | \$ 10 | \$ 10 |
| Interest Cost | 57 | 56 | 25 | 26 |
| Expected Return on Plan Assets | (83) | (78) | (23) | (22) |
| Amortization of Transition Obligation | - | - | 7 | 7 |
| Amortization of Net Actuarial Loss | 19 | 14 | 5 | 7 |
| Net Periodic Benefit Cost | \$ 17 | \$ 15 | \$ 24 | \$ 28 |

| Six Months Ended June 30, 2006 and 2005: | Pension Plans | | Other Postretirement Benefit Plans | |
|---|---------------|--------------|---------------------------------------|--------------|
| | 2006 | 2005 | 2006 | 2005 |
| | (in millions) | | | |
| Service Cost | \$ 48 | \$ 46 | \$ 20 | \$ 21 |
| Interest Cost | 114 | 112 | 50 | 53 |
| Expected Return on Plan Assets | (166) | (155) | (46) | (45) |
| Amortization of Transition Obligation | - | - | 14 | 14 |
| Amortization of Net Actuarial Loss | 39 | 27 | 10 | 14 |
| Net Periodic Benefit Cost | \$ 35 | \$ 30 | \$ 48 | \$ 57 |

10. STOCK-BASED COMPENSATION

The Amended and Restated American Electric Power System Long-Term Incentive Plan (the Plan) authorizes the use of 19,200,000 shares of AEP common stock for various types of stock-based compensation awards, including stock

option awards, to key employees. A maximum of 9,000,000 shares may be used under this plan for full value shares awards, which include performance units, restricted shares and restricted stock units. The Board of Directors and shareholders both adopted the original Plan in 2000 and the amended and restated version in 2005. Except for 10,000 stock options granted in the third quarter of 2005, the Board of Directors has not granted stock options since 2004. The following sections provide further information regarding each type of stock-based compensation award the Board of Directors has granted.

We adopted SFAS 123R, effective January 1, 2006. See the SFAS 123 (revised 2004) "Share-Based Payment" section of Note 2 for additional information.

Stock Options

For all stock options previously granted, the exercise price equaled or exceeded the market price of AEP's common stock on the date of grant. Historically the Board of Directors has granted stock options with a ten-year term that generally vest, subject to the participant's continued employment, in approximately equal 1/3 increments on January 1st of the year following the first, second and third anniversary of the grant date. Compensation cost for stock options is recorded over the vesting period based on the fair value on the grant date. The Plan does not specify a maximum contractual term for stock options.

CSW maintained a stock option plan prior to the merger with AEP in 2000. Effective with the merger, all CSW stock options outstanding were converted into AEP stock options at an exchange ratio of one CSW stock option for 0.6 of an AEP stock option. The exercise price for each CSW stock option was adjusted for the exchange ratio. Outstanding CSW stock options will continue in effect until all options are exercised, cancelled, expired or forfeited. Under the CSW stock option plan, the option price was equal to the fair market value of the stock on the grant date. All CSW options fully vested upon the completion of the merger and expire 10 years after their original grant date.

The Board of Directors did not award any stock options during the three and six months ended June 30, 2006 and 2005.

The total fair value of stock options vested and the total intrinsic value of options exercised during the three and six months ended June 30, 2006 and 2005 are as follows:

| Stock Options | Three Months Ended | | Six Months Ended | |
|--|--------------------|-------|------------------|----------|
| | 2006 | 2005 | 2006 | 2005 |
| | (in thousands) | | | |
| Fair Value of Stock Options Vested | \$ - | \$ 6 | \$ 3,665 | \$ 5,036 |
| Intrinsic Value of Options Exercised (a) | 148 | 3,337 | 1,537 | 7,657 |

(a) Intrinsic value is calculated as market price at exercise date less the option exercise price.

A summary of AEP stock option transactions during the three and six months ended June 30, 2006 is as follows:

| | Three Months Ended | | Six Months Ended | |
|------------------------------------|---------------------------|---------------------------------------|---------------------------|---------------------------------------|
| | Options (in thousands) | Weighted Average Exercise Price | Options (in thousands) | Weighted Average Exercise Price |
| Outstanding at beginning of period | 5,962 | \$ 34.11 | 6,222 | \$ 34.16 |
| Granted | - | N/A | - | N/A |

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| | | | | |
|--------------------------------------|-------|----------|-------|----------|
| Exercised/converted | (22) | 27.27 | (195) | 28.51 |
| Expired | - | N/A | - | N/A |
| Forfeited | (88) | 37.77 | (175) | 43.10 |
| Outstanding at June 30, 2006 | 5,852 | 34.08 | 5,852 | 34.08 |
| Options exercisable at June 30, 2006 | 5,587 | \$ 34.33 | 5,587 | \$ 34.33 |

The following table summarizes information about AEP stock options outstanding at June 30, 2006.

Options Outstanding

| 2006 Range of Exercise Prices | Number Outstanding (in thousands) | Weighted Average Remaining Life (in years) | Weighted Average Exercise Price | Aggregate Intrinsic Value (in thousands) |
|-------------------------------|--------------------------------------|---|---------------------------------|---|
| \$25.73 - \$27.95 | 1,443 | 6.1 | \$ 27.37 | \$ 9,924 |
| \$30.76 - \$38.65 | 4,039 | 3.5 | 35.44 | 520 |
| \$43.79 - \$49.00 | 370 | 4.9 | 45.43 | - |
| | 5,852 | 4.2 | 34.08 | \$ 10,444 |

The following table summarizes information about AEP stock options exercisable at June 30, 2006.

Options Exercisable

| 2006 Range of Exercise Prices | Number Exercisable (in thousands) | Weighted Average Remaining Life (in years) | Weighted Average Exercise Price | Aggregate Intrinsic Value (in thousands) |
|-------------------------------|--------------------------------------|---|---------------------------------|---|
| \$25.73 - \$27.95 | 1,238 | 5.9 | \$ 27.29 | \$ 8,621 |
| \$30.76 - \$35.63 | 3,979 | 3.4 | 35.50 | 347 |
| \$43.79 - \$49.00 | 370 | 4.9 | 45.43 | - |
| | 5,587 | 4.1 | 34.33 | \$ 8,968 |

The proceeds received from exercised stock options are included in common stock and paid-in capital. For options issued through December 31, 2005, the grant date fair value of each option award was estimated using a Black-Scholes option-pricing model with weighted average assumptions. Expected volatilities are estimated using the historical monthly volatility of our common stock for the 36-month period prior to each grant. A seven-year average expected term is also assumed. The risk-free rate is the yield for U.S. Treasury securities with a remaining life equal to the expected seven-year term of AEP stock options on the grant date.

Performance Units

Our performance units are equal in value to an equivalent number of shares of AEP common stock. The number of performance units held is multiplied by a performance score to determine the actual number of performance units realized. The performance score is determined at the end of the performance period based on performance measure(s) established for each grant at the beginning of the performance period by the Human Resources Committee of the Board of Directors (HR Committee) and can range from 0 percent to 200 percent. Performance units are typically paid in cash at the end of a three-year performance and vesting period, unless they are needed to satisfy a participant's stock ownership requirement, in which case they are mandatorily deferred as phantom stock units ("AEP Career Shares") until after the end of the participant's AEP career. AEP Career Shares have a value equivalent to the market value of an equal number of AEP common shares and are generally paid in cash after the participant's termination of employment.

Amounts equivalent to cash dividends on both performance units and AEP Career Shares accrue as additional units. The compensation cost for performance units is recorded over the vesting period and the liability for both the performance units and AEP Career Shares is adjusted for changes in value. The vesting period of all performance units is three years.

Our Board of Directors awarded performance units and reinvested dividends on outstanding performance units and AEP Career Shares for the three and six months ended June 30, 2006 and 2005 as follows:

| | Three Months Ended | | Six Months Ended | |
|-------------------------------|--------------------|--------|------------------|----------|
| | 2006 | 2005 | 2006 | 2005 |
| Performance Units | | | | |
| Awarded Units (in thousands) | - | - | 864 | 1,013 |
| Unit Fair Value at Grant Date | \$ N/A | \$ N/A | \$ 37.36 | \$ 34.02 |
| Vesting Period (years) | N/A | N/A | 3 | 3 |

Performance Units and AEP Career Shares (Reinvested Dividends Portion)

| | | | | |
|--|----------|----------|----------|----------|
| Awarded Units (in thousands) | 31 | 22 | 61 | 46 |
| Weighted Average Grant Date Fair Value | \$ 34.90 | \$ 35.73 | \$ 35.10 | \$ 34.94 |
| Vesting Period (years) (a) | 3 | 3 | 3 | 3 |

(a) Vesting Period (years) range from 0 - 3 years. The Vesting Period of the reinvested dividends is equal to the remaining life of the related performance units and AEP Career Shares.

In January 2006, the HR Committee certified a performance score of 49% for performance units originally granted for the 2003 through 2005 performance period. As a result, 108,486 performance units were earned. Of this amount 33,296 were mandatorily deferred as AEP Career Shares, 4,360 were voluntarily deferred into the Incentive Compensation Deferral Program and the remainder were paid in cash. The score for the 2002 through 2004 performance period was discretionarily reduced to 0% by the HR Committee so no performance units were earned, paid or deferred during the three and six months ended June 30, 2005.

The cash payouts for the three and six months ended June 30, 2006 and 2005 were as follows:

| | Three Months Ended | | Six Months Ended | |
|---|--------------------|------|------------------|-------|
| | 2006 | 2005 | 2006 | 2005 |
| (in thousands) | | | | |
| Cash payouts for Performance Units | \$ - | \$ - | \$ 2,630 | \$ - |
| Cash payouts for AEP Career Share distributions | 479 | 463 | 955 | 1,028 |

The performance unit scores for all open performance periods are dependent on two equally-weighted performance measures: three-year total shareholder return measured relative to the S&P Utilities Index and three-year cumulative earnings per share measured relative to a board-approved target. The value of each performance unit earned equals the average closing price of AEP common stock for the last 20 days of the performance period.

The fair value of performance unit awards is based on the estimated performance score and the current 20-day average closing price of AEP common stock at the date of valuation.

Restricted Shares and Restricted Stock Units

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Our Board of Directors granted 300,000 restricted shares to the Chairman, President and CEO on January 2, 2004 upon the commencement of his AEP employment. Of these restricted shares, 50,000 vested on January 1, 2005 and 50,000 vested on January 1, 2006. The remaining 200,000 restricted shares vest, subject to his continued employment, in approximately equal thirds on November 30, 2009, 2010 and 2011. Compensation cost is measured at fair value on the grant date and recorded over the vesting period. The maximum term for these restricted shares is eight years. The Board of Directors has not granted other restricted shares. Dividends on our restricted shares are paid in cash.

Our Board of Directors may also grant restricted stock units, which generally vest, subject to the participant's continued employment, over at least three years in approximately equal annual increments on the anniversaries of the grant date. Amounts equivalent to dividends paid on AEP shares accrue as additional restricted stock units that vest on the last vesting date associated with the underlying units. Compensation cost is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of units granted by the grant date market price. The maximum contractual term of these restricted stock units is six years.

In January 2006, our Board of Directors also granted restricted stock units with performance vesting conditions to certain employees who are integral to our project to design and build an IGCC power plant. Twenty percent of these awards vest on each of the first three anniversaries of the grant date. An additional 20% vest on the date the IGCC plant achieves commercial operations. The remaining 20% vest one year after the IGCC plant achieves commercial operations, subject to achievement of plant availability targets.

Our Board of Directors awarded restricted stock units, including units awarded for dividends, for the three and six months ended June 30, 2006 and 2005 as follows:

| Restricted Stock Units | Three Months Ended | | Six Months Ended | |
|--|---------------------------|-------------|-------------------------|-------------|
| | 2006 | 2005 | 2006 | 2005 |
| Awarded Units (in thousands) | 8 | 99 | 45 | 126 |
| Weighted Average Grant Date Fair Value | \$ 34.49 | \$ 35.55 | \$ 35.57 | \$ 35.03 |

The total fair value and total intrinsic value of restricted shares and restricted stock units vested during the three and six months ended June 30, 2006 and 2005 were as follows:

| Restricted Shares and Restricted Stock Units | Three Months Ended | | Six Months Ended | |
|--|---------------------------|-------------|-------------------------|-------------|
| | 2006 | 2005 | 2006 | 2005 |
| | (in thousands) | | | |
| Fair Value of Restricted Shares and Restricted Stock Units Vested | \$ 609 | \$ 26 | \$ 2,889 | \$ 2,159 |
| Intrinsic Value of Restricted Shares and Restricted Stock Units Vested | 571 | 30 | 3,515 | 2,608 |

A summary of the status of our nonvested restricted shares and restricted stock units as of June 30, 2006, and changes during the three and six months ended June 30, 2006 are as follows:

| Nonvested Restricted Shares and Restricted Stock Units | Three Months Ended | | Six Months Ended | |
|---|---------------------------|---|-------------------------|---|
| | Shares/Units | Weighted Average Grant Date Fair Value | Shares/Units | Weighted Average Grant Date Fair Value |
| | | | | |

| | (in thousands) | | (in thousands) | | |
|----------------------------------|----------------|----|----------------|----|-------|
| Nonvested at beginning of period | 454 | \$ | 33.06 | \$ | 32.19 |
| Granted | 8 | | 34.49 | | 35.57 |
| Vested | (17) | | 35.36 | | 30.04 |
| Forfeited | (15) | | 35.59 | | 35.49 |
| Nonvested at June 30, 2006 | 430 | | 32.91 | | 32.91 |

The total aggregate intrinsic value of nonvested restricted shares and restricted stock units as of June 30, 2006 was \$14.7 million and the weighted average remaining contractual life was 3.05 years.

Share-based Compensation Plans

Compensation cost and the actual tax benefit realized for the tax deductions from compensation cost for share-based payment arrangements recognized in income and total compensation cost capitalized in relation to the cost of an asset for the three and six months ended June 30, 2006 and 2005 were as follows:

| Share-based Compensation Plans | Three Months Ended | | Six Months Ended | | | | | |
|--|--------------------|-------|------------------|-------|----|-------|----|-------|
| | 2006 | 2005 | 2006 | 2005 | | | | |
| | (in thousands) | | | | | | | |
| Compensation cost for share-based payment arrangements | \$ | 1,209 | \$ | 5,352 | \$ | 3,639 | \$ | 8,268 |
| Actual tax benefit realized | | 424 | | 1,873 | | 1,274 | | 2,894 |
| Total compensation cost capitalized | | 42 | | 995 | | 620 | | 1,396 |

During the three and six months ended June 30, 2006 and 2005, there were no significant modifications affecting any of our share-based payment arrangements.

As of June 30, 2006, there was \$43 million of total unrecognized compensation cost related to unvested share-based compensation arrangements granted under the Plan. Unrecognized compensation cost related to the performance units and AEP Career Shares will change as the liability is revalued each period and forfeitures for all award types are realized. Our unrecognized compensation cost will be recognized over a weighted-average period of 1.63 years.

Cash received from stock options exercised and actual tax benefit realized for the tax deductions from stock options exercised during the three and six months ended June 30, 2006 and 2005 were as follows:

| Share-based Compensation Plans | Three Months Ended | | Six Months Ended | | | | | |
|---|--------------------|------|------------------|--------|----|-------|----|--------|
| | 2006 | 2005 | 2006 | 2005 | | | | |
| | (in thousands) | | | | | | | |
| Cash received from stock options exercised | \$ | 609 | \$ | 13,260 | \$ | 5,561 | \$ | 28,413 |
| Actual tax benefit realized for the tax deductions from stock options exercised | | 52 | | 1,160 | | 538 | | 2,675 |

Our practice is to use authorized but unissued shares to fulfill share commitments for stock option exercises and restricted stock unit vesting. Although we do not currently anticipate any changes to this practice, we could use reacquired shares, shares acquired in the open market specifically for distribution under the Plan or any combination thereof for this purpose. The number of new shares issued to fulfill vesting restricted stock units is generally reduced, at the participant's election, to offset AEP's tax withholding obligation.

11. INCOME TAXES

In the second quarter of 2006, the Texas state legislature replaced the existing franchise/income tax with a gross margin tax at a 1% rate for electric utilities. Overall, the new law reduces Texas income tax rates and is effective January 1, 2007. The new gross margin tax is income-based for purposes of the application of SFAS 109 "Accounting for Income Taxes." Based on the new law, we reviewed deferred tax liabilities with consideration given to the rate changes and changes to the allowed deductible items with temporary differences. As a result, in the second quarter of 2006 we recorded a net reduction to Deferred Income Taxes on the Condensed Consolidated Balance Sheet of \$48 million of which \$2 million was credited to Income Tax Expense and \$46 million credited to Regulatory Assets based upon the related rate-making treatment.

12. BUSINESS SEGMENTS

As outlined in our 2005 Annual Report, our business strategy and the core of our business are to focus on domestic electric utility operations. Our previous decision to no longer pursue business interests outside of our domestic core utility assets led us to divest such noncore assets. Consequently, the significance of our three Investments segments has declined.

Our segments and their related business activities are as follows:

Utility Operations

- Generation of electricity for sale to U.S. retail and wholesale customers.
- Electricity transmission and distribution in the U.S.

Investments - Gas Operations

- Gas pipeline and storage services.
- Gas marketing and risk management activities.
- We disposed of our gas pipeline and storage assets in 2005 with the sale of HPL (see "Dispositions" section of Note 8).

Investments - UK Operations

- International generation of electricity for sale to wholesale customers.
- Coal procurement and transportation to our plants.
- We classified UK Operations as Discontinued Operations during 2003 and sold them in 2004.

Investments - Other

- Bulk commodity barging operations, wind farms, IPPs and other energy supply-related businesses.

The tables below present segment income statement information for the three and six months ended June 30, 2006 and 2005 and balance sheet information as of June 30, 2006 and December 31, 2005. These amounts include certain estimates and allocations where necessary. Prior year amounts have been reclassified to conform to the current year's presentation.

Investments

Other

Consolidated

| | Utility Operations | Gas Operations | UK Operations | | All Other (a) | Reconciling Adjustments | |
|--|-----------------------|-------------------|------------------|--|---------------------|----------------------------|--|
|--|-----------------------|-------------------|------------------|--|---------------------|----------------------------|--|

(in millions)

**Three Months Ended
June 30, 2006**

Revenues from:

| | | | | | | | |
|--------------------------|-----------------|-------------|-------------|---------------|-------------|---------------|-----------------|
| External Customers | \$ 2,810 | \$ (15) | \$ - | \$ 141 | \$ - | \$ - | \$ 2,936 |
| Other Operating Segments | (11) | 17 | - | 2 | - | (8) | - |
| Total Revenues | \$ 2,799 | \$ 2 | \$ - | \$ 143 | \$ - | \$ (8) | \$ 2,936 |

Income (Loss) Before

| | | | | | | | |
|--|---------------|-------------|-------------|--------------|---------------|-------------|---------------|
| Discontinued Operations | \$ 160 | \$ 2 | \$ - | \$ 13 | \$ (3) | \$ - | \$ 172 |
| Discontinued Operations, Net of Tax | - | - | 3 | - | - | - | 3 |
| Net Income (Loss) | \$ 160 | \$ 2 | \$ 3 | \$ 13 | \$ (3) | \$ - | \$ 175 |

Investments

| | Utility Operations | Gas Operations | UK Operations | Other | All Other (a) | Reconciling Adjustments | Consolidated |
|--|-----------------------|-------------------|------------------|-------|---------------------|----------------------------|--------------|
|--|-----------------------|-------------------|------------------|-------|---------------------|----------------------------|--------------|

(in millions)

**Three Months Ended
June 30, 2005**

Revenues from:

| | | | | | | | |
|--------------------------|-----------------|-------------|-------------|---------------|-------------|---------------|-----------------|
| External Customers | \$ 2,680 | \$ 19 | \$ - | \$ 120 | \$ - | \$ - | \$ 2,819 |
| Other Operating Segments | 22 | (17) | - | 3 | - | (8) | - |
| Total Revenues | \$ 2,702 | \$ 2 | \$ - | \$ 123 | \$ - | \$ (8) | \$ 2,819 |

Income (Loss) Before

| | | | | | | | |
|--|---------------|---------------|-------------|-------------|----------------|-------------|---------------|
| Discontinued Operations | \$ 247 | \$ (2) | \$ - | \$ (1) | \$ (26) | \$ - | \$ 218 |
| Discontinued Operations, Net of Tax | - | - | - | 3 | - | - | 3 |
| Net Income (Loss) | \$ 247 | \$ (2) | \$ - | \$ 2 | \$ (26) | \$ - | \$ 221 |

Investments

| | Utility Operations | Gas Operations | UK Operations | Other | All Other (a) | Reconciling Adjustments | Consolidated |
|--|-----------------------|-------------------|------------------|-------|---------------------|----------------------------|--------------|
|--|-----------------------|-------------------|------------------|-------|---------------------|----------------------------|--------------|

(in millions)

**Six Months Ended
June 30, 2006**

Revenues from:

| | | | | | | | |
|--------------------------|-----------------|-------------|-------------|---------------|-------------|----------------|-----------------|
| External Customers | \$ 5,797 | \$ (33) | \$ - | \$ 280 | \$ - | \$ - | \$ 6,044 |
| Other Operating Segments | (29) | 38 | - | 5 | 1 | (15) | - |
| Total Revenues | \$ 5,768 | \$ 5 | \$ - | \$ 285 | \$ 1 | \$ (15) | \$ 6,044 |

Income (Loss) Before

| | | | | | | | |
|-------------------------|--------|------|------|-------|--------|------|--------|
| Discontinued Operations | \$ 525 | \$ 1 | \$ - | \$ 29 | \$ (5) | \$ - | \$ 550 |
| | - | - | 6 | - | - | - | 6 |

Discontinued Operations, Net of
Tax

| | | | | | | | |
|-------------------|--------|------|------|-------|--------|------|--------|
| Net Income (Loss) | \$ 525 | \$ 1 | \$ 6 | \$ 29 | \$ (5) | \$ - | \$ 556 |
|-------------------|--------|------|------|-------|--------|------|--------|

Investments

| | Utility Operations | Gas Operations | UK Operations | Other | All Other (a) | Reconciling Adjustments | Consolidated |
|--|-----------------------|-------------------|------------------|-------|---------------------|----------------------------|--------------|
|--|-----------------------|-------------------|------------------|-------|---------------------|----------------------------|--------------|

(in millions)

Three Months Ended
June 30, 2005

Revenues from:

| | | | | | | | |
|--------------------------|----------|--------|------|--------|------|---------|----------|
| External Customers | \$ 5,285 | \$ 376 | \$ - | \$ 223 | \$ - | \$ - | \$ 5,884 |
| Other Operating Segments | 101 | (90) | - | 9 | 1 | (21) | - |
| Total Revenues | \$ 5,386 | \$ 286 | \$ - | \$ 232 | \$ 1 | \$ (21) | \$ 5,884 |

Income (Loss) Before

| | | | | | | | |
|-------------------------|--------|------|------|------|---------|------|--------|
| Discontinued Operations | \$ 600 | \$ 8 | \$ - | \$ 4 | \$ (40) | \$ - | \$ 572 |
|-------------------------|--------|------|------|------|---------|------|--------|

Discontinued Operations, Net of

| | | | | | | | |
|-------------------|--------|------|--------|-------|---------|------|--------|
| Tax | - | - | (5) | 9 | - | - | 4 |
| Net Income (Loss) | \$ 600 | \$ 8 | \$ (5) | \$ 13 | \$ (40) | \$ - | \$ 576 |

Investments

| | Utility Operations | Gas Operations | UK Operations | Other | All Other (b) | Reconciling Adjustments (b) | Consolidated |
|--|-----------------------|-------------------|------------------|-------|---------------------|-----------------------------------|--------------|
|--|-----------------------|-------------------|------------------|-------|---------------------|-----------------------------------|--------------|

(in millions)

As of June 30, 2006

| | | | | | | | |
|---|-----------|-----------|-----------|--------|-----------|-------------|-----------|
| Total Property, Plant and Equipment | \$ 39,653 | \$ 1 | \$ - | \$ 834 | \$ 3 | \$ - | \$ 40,491 |
| Accumulated Depreciation and Amortization | 14,965 | - | - | 126 | 2 | - | 15,093 |
| Total Property, Plant and Equipment - Net | \$ 24,688 | \$ 1 | \$ - | \$ 708 | \$ 1 | \$ - | \$ 25,398 |
| Total Assets | \$ 34,689 | \$ 735(c) | \$ 630(d) | \$ 577 | \$ 10,400 | \$ (10,847) | \$ 36,184 |
| Assets Held for Sale | 46 | - | - | - | - | - | 46 |

Investments

| | Utility Operations | Gas Operations | UK Operations | Other | All Other (b) | Reconciling Adjustments (b) | Consolidated |
|--|-----------------------|-------------------|------------------|-------|---------------------|-----------------------------------|--------------|
|--|-----------------------|-------------------|------------------|-------|---------------------|-----------------------------------|--------------|

(in millions)

As of December 31, 2005

| | | | | | | | |
|---|-----------|------|------|--------|------|------|-----------|
| Total Property, Plant and Equipment | \$ 38,283 | \$ 2 | \$ - | \$ 833 | \$ 3 | \$ - | \$ 39,121 |
| Accumulated Depreciation and Amortization | 14,723 | 1 | - | 112 | 1 | - | 14,837 |

| | | | | | | | |
|---|-----------|-------------|-----------|--------|----------|------------|-----------|
| Total Property, Plant and Equipment - Net | \$ 23,560 | \$ 1 | \$ - | \$ 721 | \$ 2 | \$ - | \$ 24,284 |
| Total Assets | \$ 34,339 | \$ 1,199(e) | \$ 632(f) | \$ 509 | \$ 9,463 | \$ (9,970) | \$ 36,172 |
| Assets Held for Sale | 44 | - | - | - | - | - | 44 |

- (a) All Other includes the parent company's interest income and expense, as well as other nonallocated costs.
- (b) Reconciling Adjustments for Total Assets primarily include the elimination of intercompany advances to affiliates and intercompany accounts receivable along with the elimination of AEP's investments (included in All Other) in subsidiary companies.
- (c) Total Assets of \$735 million for the Investments-Gas Operations segment include \$344 million in affiliated accounts receivable related to the corporate borrowing program and risk management contracts that are eliminated in consolidation. The majority of the remaining \$391 million in assets represents third party risk management contracts, margin deposits, and accounts receivable.
- (d) Total Assets of \$630 million for the Investments-UK Operations segment include \$614 million in affiliated accounts receivable related mainly to federal income taxes that are eliminated in consolidation. The majority of the remaining \$16 million in assets represents value-added tax receivables.
- (e) Total Assets of \$1.2 billion for the Investments-Gas Operations segment include \$429 million in affiliated accounts receivable related to the corporate borrowing program and risk management contracts that are eliminated in consolidation. The majority of the remaining \$770 million in assets represents third party risk management contracts, margin deposits, and accounts receivable.
- (f) Total Assets of \$632 million for the Investments-UK Operations segment include \$613 million in affiliated accounts receivable related to federal income taxes that are eliminated in consolidation. The majority of the remaining \$19 million in assets represents cash equivalents and value-added tax receivables.

13. FINANCING ACTIVITIES

Short-term Debt

Short-term debt is used to fund our corporate borrowing program and fund other short-term cash needs. Our outstanding short-term debt is as follows:

| Type of Debt | June 30, 2006 | December 31, 2005 |
|-----------------------------|------------------|----------------------|
| | (in millions) | |
| Commercial Paper - AEP (a) | \$ 144 | \$ - |
| Commercial Paper - JMG (b) | 5 | 10 |
| Line of Credit - Sabine (c) | 10 | - |
| | \$ 159 | \$ 10 |

(a) The interest rate at June 30, 2006 was 5.37%.

(b) The interest rate at June 30, 2006 and December 31, 2005 was 5.47% and 4.47%, respectively.

(c) The interest rate at June 30, 2006 was 6.38%.

Long-term Debt

Our outstanding long-term debt is as follows:

| Type of Debt | June 30, 2006 | December 31, 2005 |
|---|------------------|----------------------|
| | (in millions) | |
| Pollution Control Bonds | \$ 2,051 | \$ 1,935 |
| Senior Unsecured Notes | 8,677 | 8,226 |
| First Mortgage Bonds | 96 | 196 |
| Defeased First Mortgage Bonds (a) | 26 | 26 |
| Notes Payable | 886 | 904 |
| Securitization Bonds | 617 | 648 |
| Notes Payable To Trust | 113 | 113 |
| Other Long-Term Debt (b) | 244 | 236 |
| Unamortized Discount (net) | (65) | (58) |
| Total Long-term Debt Outstanding | 12,645 | 12,226 |
| Less Portion Due Within One Year | 800 | 1,153 |
| Long-term Portion | \$ 11,845 | \$ 11,073 |

(a) In May 2004, we deposited cash and treasury securities with a trustee to defease all of TCC's outstanding First Mortgage Bonds. The defeased TCC First Mortgage Bonds had a balance of \$18 million at both June 30, 2006 and December 31, 2005. Trust fund assets related to this obligation of \$2 million are included in Other Temporary Cash Investments at both June 30, 2006 and December 31, 2005 and \$21 million is included in Other Noncurrent Assets in the Condensed Consolidated Balance Sheets at both June 30, 2006 and December 31, 2005. In December 2005, we deposited cash and treasury securities with a trustee to defease the remaining TNC outstanding First Mortgage Bond. The defeased TNC First Mortgage Bond had a balance of \$8 million at both June 30, 2006 and December 31, 2005. Trust fund assets related to this obligation of \$9 million and \$1 million at June 30, 2006 and December 31, 2005, respectively, are included in Other Temporary Cash Investments and \$0 and \$8 million are included in Other Noncurrent Assets in the Condensed Consolidated Balance Sheets at June 30, 2006 and December 31, 2005, respectively. 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. Trust fund assets of \$267 million and \$264 million related to this obligation are included in Spent Nuclear Fuel and Decommissioning Trusts in the Condensed Consolidated Balance Sheets at June 30, 2006 and December 31, 2005, respectively.

Long-term debt issued, retired and principal payments made during the first six months of 2006 are shown in the tables below.

| Company | Type of Debt | Principal Amount (in millions) | Interest Rate (%) | Due Date |
|------------------------|-------------------------|-----------------------------------|----------------------|----------|
| Issuances: | | | | |
| APCo | Pollution Control Bonds | \$ 50 | Variable | 2036 |
| APCo | Senior Unsecured Note | 250 | 5.55 | 2011 |
| APCo | Senior Unsecured Note | 250 | 6.375 | 2036 |
| I&M | Pollution Control Bonds | 50 | Variable | 2025 |
| OPCo | Pollution Control Bonds | 65 | Variable | 2036 |
| OPCo | Senior Unsecured Note | 350 | 6.00 | 2016 |
| SWEPCo | Pollution Control Bonds | 82 | Variable | 2018 |
| Total Issuances | | \$ 1,097(a) | | |

The above borrowing arrangements do not contain guarantees, collateral or dividend restrictions.

(a) Amount indicated on statement of cash flows of \$1,081 million is net of issuance costs and unamortized premium or discount.

In July 2006, AEGCo remarketed its outstanding \$45 million pollution control bonds, resulting in a new interest rate of 4.15%. No proceeds were received related to this remarketing. The principal amount of the pollution control bonds is reflected in Long-term Debt on our Condensed Consolidated Balance Sheet as of June 30, 2006.

| Company | Type of Debt | Principal Amount Paid (in millions) | Interest Rate (%) | Due Date |
|--|-------------------------|---|----------------------|----------|
| Retirements and Principal Payments: | | | | |
| AEP | Senior Unsecured Note | \$ 396 | 6.125 | 2006 |
| APCo | First Mortgage Bonds | 100 | 6.80 | 2006 |
| I&M | Pollution Control Bonds | 50 | 6.55 | 2025 |
| OPCo | Notes Payable | 3 | 6.81 | 2008 |
| OPCo | Notes Payable | 3 | 6.27 | 2009 |
| SWEPCo | Notes Payable | 3 | 4.47 | 2011 |
| SWEPCo | Notes Payable | 1 | Variable | 2008 |

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| | | | | |
|------------------------------|----------------------|----|----------|------|
| SWEPCo | Pollution Control | | | 2018 |
| | Bonds | 82 | 6.10 | |
| TCC | Securitization Bonds | 31 | 5.01 | 2010 |
| Non-Registrant: | | | | |
| AEP Subsidiaries | Notes Payable | 3 | Variable | 2017 |
| CSW Energy | Notes Payable | 4 | 5.88 | 2011 |
| Total Retirements and | | | | |
| Principal | | | | |
| Payments | | | | |
| | | \$ | 676 | |

Credit Facilities

In April 2006, we amended the terms and increased the size of our credit facilities from \$2.7 billion to \$3 billion. The amended facilities are structured as two \$1.5 billion credit facilities, with an option in each to issue up to \$200 million as letters of credit, expiring separately in March 2010 and April 2011. We also terminated an existing \$200 million letter of credit facility.

AEP GENERATING COMPANY

AEP GENERATING COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

As co-owner of the Rockport Plant, we engage in the generation and wholesale sale of electric power to two affiliates, I&M and KPCo, under long-term agreements. I&M is the operator and co-owner of the Rockport Plant.

We derive operating revenues from the sale of Rockport Plant energy and capacity to I&M and KPCo pursuant to FERC approved long-term unit power agreements. The unit power agreements provide for a FERC-approved rate of return on common equity, a return on other capital (net of temporary cash investments) and recovery of costs including operation and maintenance, fuel and taxes. Under the terms of the unit power agreements, we accumulate all expenses monthly and prepare bills for our affiliates. In the month the expenses are incurred, we recognize the billing revenues and establish a receivable from the affiliated companies. Costs of operating the plant are divided between the co-owners.

Results of Operations

Net Income increased \$0.1 million for the second quarter of 2006 compared with the second quarter of 2005. Net Income increased \$0.5 million for the six months ended 2006 compared with the six months ended 2005. The fluctuation in Net Income is a result of terms in the unit power agreements which allow for a return on total capital of the Rockport Plant which is calculated and adjusted monthly.

Second Quarter of 2006 Compared to Second Quarter of 2005

**Reconciliation of Second Quarter of 2005 to Second Quarter of 2006 Net Income
(in millions)**

| | | |
|---|-----------|------------|
| Second Quarter of 2005 | \$ | 2.1 |
| Change in Gross Margin: | | |
| Wholesale Sales | | 0.3 |
| Changes in Operating Expenses and Other: | | |
| Other Operation and Maintenance | 0.3 | |
| Interest Expense | (0.1) | |
| Total Change in Operating Expenses and Other | | 0.2 |
| Income Tax Expense | | (0.4) |
| Second Quarter of 2006 | \$ | 2.2 |

Gross Margin, defined as Operating Revenues less Fuel for Electric Generation, increased \$0.3 million primarily due to recovery of higher expenses and higher returns earned on plant and capital investment.

The decrease in Other Operation and Maintenance expenses resulted from decreased maintenance cost at Rockport Plant during 2006 due to the timing of outages in 2006 and 2005.

Income Taxes

The increase in Income Tax Expense is primarily due to an increase in pretax book income, state income taxes and changes in certain book/tax differences accounted for on a flow-through basis.

Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2005

**Reconciliation of Six Months Ended June 30, 2005 to Six Months Ended June 30, 2006 Net Income
(in millions)**

| | |
|---|---------------|
| Six Months Ended June 30, 2005 | \$ 4.6 |
| Change in Gross Margin: | |
| Wholesale Sales | 3.0 |
| Changes in Operating Expenses and Other: | |
| Other Operation and Maintenance | (1.4) |
| Interest Expense | (0.2) |
| Total Change in Operating Expenses and Other | (1.6) |
| Income Tax Expense | (0.9) |
| Six Months Ended June 30, 2006 | \$ 5.1 |

Gross Margin, defined as Operating Revenues less Fuel for Electric Generation, increased \$3 million primarily due to recovery of higher expenses and higher returns earned on plant and capital investment.

The increase in Other Operation and Maintenance expenses resulted from increased maintenance cost at Rockport Plant during a planned outage in 2006 and credits allocated to us in February 2005 from the cancellation and settlement of corporate owned life insurance policies.

Income Taxes

The increase in Income Tax Expense is primarily due to an increase in pretax book income, state income taxes and changes in certain book/tax differences accounted for on a flow-through basis.

Off-Balance Sheet Arrangements

In prior years, we entered into an off-balance sheet arrangement for the lease of Rockport Plant Unit 2. Our current guidelines restrict the use of off-balance sheet financing entities or structures to allow only traditional operating lease arrangements. Our off-balance sheet arrangement has not changed significantly since year-end. For complete information on our off-balance sheet arrangement see "Off-balance Sheet Arrangements" in the "Management's Narrative Financial Discussion and Analysis" section of our 2005 Annual Report.

Summary Obligation Information

A summary of our contractual obligations is included in our 2005 Annual Report and has not changed significantly from year-end.

Significant Factors

In July 2006, we remarketed \$45 million of pollution control bonds at a rate of 4.15% compared to a previous rate of 4.05% until July 14, 2011, the next remarketing date.

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

Critical Accounting Estimates

See the “Critical Accounting Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” in the 2005 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets and the impact of new accounting pronouncements.

AEP GENERATING COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2006 and 2005
(Unaudited)
(in thousands)

| | Three Months Ended | | Six Months Ended | |
|--|---------------------------|-----------------|-------------------------|-----------------|
| | 2006 | 2005 | 2006 | 2005 |
| OPERATING REVENUES | \$ 77,195 | \$ 65,082 | \$ 155,346 | \$ 131,628 |
| EXPENSES | | | | |
| Fuel for Electric Generation | 45,087 | 33,233 | 89,048 | 68,368 |
| Rent - Rockport Plant Unit 2 | 17,071 | 17,071 | 34,142 | 34,142 |
| Other Operation | 3,122 | 3,126 | 6,217 | 5,573 |
| Maintenance | 1,930 | 2,272 | 4,716 | 3,990 |
| Depreciation and Amortization | 5,959 | 5,989 | 11,907 | 11,945 |
| Taxes Other Than Income Taxes | 1,028 | 1,051 | 2,098 | 2,075 |
| TOTAL | 74,197 | 62,742 | 148,128 | 126,093 |
| OPERATING INCOME | 2,998 | 2,340 | 7,218 | 5,535 |
| Other Income (Expense): | | | | |
| Interest Income | - | 24 | - | 24 |
| Allowance for Equity Funds Used During Construction | 24 | 60 | 24 | 60 |
| Interest Expense | (641) | (562) | (1,363) | (1,196) |
| INCOME BEFORE INCOME TAXES | 2,381 | 1,862 | 5,879 | 4,423 |
| Income Tax Expense (Credit) | 161 | (211) | 731 | (166) |
| NET INCOME | \$ 2,220 | \$ 2,073 | \$ 5,148 | \$ 4,589 |

CONDENSED STATEMENTS OF RETAINED EARNINGS
For the Three and Six Months Ended June 30, 2006 and 2005
(Unaudited)
(in thousands)

| | Three Months Ended | | Six Months Ended | |
|---|---------------------------|------------------|-------------------------|------------------|
| | 2006 | 2005 | 2006 | 2005 |
| BALANCE AT BEGINNING OF PERIOD | \$ 26,968 | \$ 25,813 | \$ 26,038 | \$ 24,237 |
| Net Income | 2,220 | 2,073 | 5,148 | 4,589 |
| Cash Dividends Declared | 2,012 | 939 | 4,010 | 1,879 |
| BALANCE AT END OF PERIOD | \$ 27,176 | \$ 26,947 | \$ 27,176 | \$ 26,947 |

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY
CONDENSED BALANCE SHEETS
ASSETS
June 30, 2006 and December 31, 2005
(Unaudited)
(in thousands)

| | 2006 | 2005 |
|--|-------------------|-------------------|
| CURRENT ASSETS | | |
| Accounts Receivable - Affiliated Companies | \$ 26,930 | \$ 29,671 |
| Fuel | 18,513 | 14,897 |
| Materials and Supplies | 7,614 | 7,017 |
| Accrued Tax Benefits | 1,311 | 2,074 |
| Prepayments and Other | 88 | 9 |
| TOTAL | 54,456 | 53,668 |
| PROPERTY, PLANT AND EQUIPMENT | | |
| Electric - Production | 689,407 | 684,721 |
| Other | 2,342 | 2,369 |
| Construction Work in Progress | 9,759 | 12,252 |
| Total | 701,508 | 699,342 |
| Accumulated Depreciation and Amortization | 393,630 | 382,925 |
| TOTAL - NET | 307,878 | 316,417 |
| Noncurrent Assets | 8,409 | 6,618 |
| TOTAL ASSETS | \$ 370,743 | \$ 376,703 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
June 30, 2006 and December 31, 2005
(Unaudited)

| | 2006 | 2005 |
|---|-------------------|-------------------|
| | (in thousands) | |
| CURRENT LIABILITIES | | |
| Advances from Affiliates | \$ 36,989 | \$ 35,131 |
| Accounts Payable: | | |
| General | 494 | 926 |
| Affiliated Companies | 17,351 | 22,161 |
| Long-term Debt Due Within One Year | - | 44,828 |
| Accrued Taxes | 5,486 | 3,055 |
| Accrued Rent - Rockport Plant Unit 2 | 4,963 | 4,963 |
| Other | 1,319 | 1,228 |
| TOTAL | 66,602 | 112,292 |
| NONCURRENT LIABILITIES | | |
| Long-term Debt | 44,833 | - |
| Deferred Income Taxes | 21,765 | 23,617 |
| Asset Retirement Obligations | 1,400 | 1,370 |
| Regulatory Liabilities and Deferred Investment Tax Credits | 81,154 | 82,689 |
| Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2 | 91,548 | 94,333 |
| Obligations Under Capital Leases | 11,831 | 11,930 |
| TOTAL | 252,531 | 213,939 |
| TOTAL LIABILITIES | 319,133 | 326,231 |
| Commitments and Contingencies (Note 5) | | |
| COMMON SHAREHOLDER'S EQUITY | | |
| Common Stock - \$1,000 Par Value Per Share | | |
| Authorized and Outstanding - 1,000 Shares | 1,000 | 1,000 |
| Paid-in Capital | 23,434 | 23,434 |
| Retained Earnings | 27,176 | 26,038 |
| TOTAL | 51,610 | 50,472 |
| TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY | \$ 370,743 | \$ 376,703 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

| | 2006 | 2005 |
|---|----------------|----------------|
| OPERATING ACTIVITIES | | |
| Net Income | \$ 5,148 | \$ 4,589 |
| Adjustments for Noncash Items: | | |
| Depreciation and Amortization | 11,907 | 11,945 |
| Deferred Income Taxes | (2,298) | (2,379) |
| Deferred Investment Tax Credits | (1,655) | (1,668) |
| Amortization of Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2 | (2,785) | (2,785) |
| Deferred Property Taxes | (1,813) | (1,950) |
| Changes in Other Noncurrent Assets | (456) | (1,270) |
| Changes in Other Noncurrent Liabilities | 579 | 1,648 |
| Changes in Components of Working Capital: | | |
| Accounts Receivable | 2,741 | (1,081) |
| Fuel, Materials and Supplies | (4,213) | 4,265 |
| Accounts Payable | (5,242) | (2,405) |
| Accrued Taxes, Net | 3,194 | (2,042) |
| Other Current Assets | (79) | (26) |
| Other Current Liabilities | 91 | 354 |
| Net Cash Flows From Operating Activities | 5,119 | 7,195 |
| INVESTING ACTIVITIES | | |
| Construction Expenditures | (2,816) | (2,882) |
| FINANCING ACTIVITIES | | |
| Change in Advances from Affiliates, Net | 1,858 | (2,294) |
| Principal Payments for Capital Lease Obligations | (151) | (140) |
| Dividends Paid | (4,010) | (1,879) |
| Net Cash Flows Used For Financing Activities | (2,303) | (4,313) |
| Net Change in Cash and Cash Equivalents | - | - |
| Cash and Cash Equivalents at Beginning of Period | - | - |
| Cash and Cash Equivalents at End of Period | \$ - | \$ - |
| SUPPLEMENTARY INFORMATION | | |
| Cash Paid for Interest, Net of Capitalized Amounts | \$ 1,230 | \$ 1,063 |
| Cash Paid for Income Taxes, Net of Refunds | 3,624 | 8,080 |
| Noncash Acquisitions Under Capital Leases | 74 | 26 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP GENERATING COMPANY
INDEX TO CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT
SUBSIDIARIES

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

| | Footnote Reference |
|---|-------------------------------|
| Significant Accounting Matters | Note 1 |
| New Accounting Pronouncements | Note 2 |
| Commitments and Contingencies | Note 5 |
| Guarantees | Note 6 |
| Company-wide Staffing and Budget Review | Note 7 |
| Business Segments | Note 11 |
| Financing Activities | Note 12 |

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY

**AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS**

Allocation Agreement between AEP East companies and AEP West companies

Under the Texas Restructuring Legislation, we are completing the final stage of exiting the generation business and have ceased serving retail load. Based on the corporate separation and generation divestiture activities underway, the nature of our business is no longer compatible with our participation in the CSW Operating Agreement and the SIA since these agreements involve the coordinated planning and operation of power supply facilities. Accordingly, on behalf of the AEP East companies and the AEP West companies, AEPSC filed with the FERC to remove us from those agreements. The FERC approved the filing in March 2006. The SIA includes a methodology for sharing trading and marketing margins among the AEP East companies and the AEP West companies. Therefore, our sharing of margins under the CSW Operating Agreement and the SIA ceased effective May 1, 2006, which affects our future results of operations and cash flows. We will continue to have margin and collateral deposits, risk management assets and liabilities and trading gains or losses to the extent that we have contracts dedicated specifically to us. As of June 30, 2006, we have no dedicated contracts.

Results of Operations

Second Quarter of 2006 Compared to Second Quarter of 2005

**Reconciliation of Second Quarter of 2005 to Second Quarter of 2006 Net Income
(in millions)**

| | | |
|---|------|------|
| Second Quarter of 2005 | \$ | 28 |
| Changes in Gross Margin: | | |
| Texas Supply | (30) | |
| Texas Wires | 8 | |
| Off-system Sales | (2) | |
| Transmission Revenues | (4) | |
| Other | (1) | |
| Total Change in Gross Margin | | (29) |
| Changes in Operating Expenses and Other: | | |
| Other Operation and Maintenance | 17 | |
| Depreciation and Amortization | (2) | |
| Taxes Other Than Income Taxes | 4 | |
| Other Income (Expense), Net | (1) | |
| Total Change in Operating Expenses and Other | | 18 |
| Second Quarter of 2006 | \$ | 17 |

Net Income decreased \$11 million in the second quarter of 2006. The key drivers of the decrease were a \$29 million decrease in Gross Margin, partially offset by a reduction in Other Operation and Maintenance expenses of \$17 million. We substantially exited the generation market with the sale of STP in May 2005.

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

- Texas Supply margins decreased \$30 million primarily due to the sale of STP, which resulted in lower nonaffiliated sales of \$38 million, and a \$5 million provision for refund primarily due to the fuel reconciliation adjustment in 2005. These decreases were partially offset by lower fuel and purchased power expenses of \$12 million.
- Texas Wires revenues increased \$8 million primarily due to an increase in sales volumes resulting mainly from a 23% increase in cooling degree days.
- Margins from Off-system Sales decreased \$2 million primarily due to lower optimization activities.
- Transmission Revenues decreased \$4 million primarily due to lower ERCOT transmission rates and reduced affiliated transmission fees resulting from the elimination of the affiliated OATT.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased \$17 million primarily due to a \$7 million decrease in power plant operations, a \$4 million decrease in plant maintenance and the absence of \$3 million in accretion expense all related to the sale of the STP. Customer service and administrative and general expenses decreased \$6 million partially offset by increased transmission-related expense of \$3 million.
- Taxes Other than Income Taxes decreased \$4 million due to the favorable settlement of a state use tax audit in 2006.

Income Taxes

Income Tax Expense remained relatively flat for the second quarter of 2006 compared to the second quarter of 2005.

Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2005

Reconciliation of Six Months Ended June 30, 2005 to Six Months Ended June 30, 2006 Net Income (in millions)

| | |
|---|--------------|
| Six Months Ended June 30, 2005 | \$ 30 |
| Changes in Gross Margin: | |
| Texas Supply | (74) |
| Texas Wires | 11 |
| Off-system Sales | (2) |
| Transmission Revenues | (9) |
| Other | (3) |
| Total Change in Gross Margin | (77) |
| Changes in Operating Expenses and Other: | |
| Other Operation and Maintenance | 48 |
| Depreciation and Amortization | (6) |
| Taxes Other Than Income Taxes | 6 |
| Interest Income and Expense, Net | (3) |
| Carrying Costs on Stranded Cost Recovery | 25 |
| Total Change in Operating Expenses and Other | 70 |
| Income Tax Expense | (2) |

Six Months Ended June 30, 2006**\$ 21**

Net Income decreased \$9 million in the first six months of 2006. The key drivers of the decrease were a \$77 million decrease in Gross Margin, partially offset by a reduction in Other Operation and Maintenance expenses of \$48 million and increased Carrying Costs on Stranded Cost Recovery of \$25 million. We substantially exited the generation market with the sale of STP in May 2005.

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

- Texas Supply margins decreased \$74 million primarily due to the sale of STP which resulted in lower nonaffiliated sales of \$98 million and a \$6 million provision for refund primarily due to the fuel reconciliation adjustment in 2005. These decreases were partially offset by lower fuel and purchased power expenses of \$30 million.
- Texas Wires revenues increased \$11 million primarily due to an increase in sales volumes resulting mainly from a 28% increase in cooling degree days.
- Margins from Off-system Sales decreased \$2 million primarily due to lower optimization activities.
- Transmission Revenues decreased \$9 million primarily due to lower ERCOT transmission rates and reduced affiliated transmission fees resulting from the elimination of the affiliated OATT.
- Other revenues decreased \$3 million primarily due to lower third party construction project revenues related to work performed for the Lower Colorado River Authority.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased \$48 million primarily due to a \$14 million decrease in power plant operations, a \$13 million decrease in plant maintenance and the absence of \$8 million in accretion expense all related to the sale of STP. An additional \$5 million decrease resulted from lower expenses related to construction activities performed for third parties, primarily the Lower Colorado River Authority.
- Depreciation and Amortization expense increased \$6 million primarily related to the refund and amortization of excess earnings credits in 2005 partially offset by the recovery and amortization of securitized assets.
- Taxes Other Than Income Taxes decreased \$6 million primarily due to lower property-related taxes as a result of the sale of STP in 2005 and the favorable settlement of a state use tax audit in 2006.
- Interest Income and Expense, Net changed unfavorably \$3 million primarily due to higher interest on long-term debt and interest related to the Texas competition transition charge liability (See "Texas Restructuring" section of Note 4) partially offset by lower short-term interest expense.
- Carrying Costs on Stranded Cost Recovery increased \$25 million primarily due to a \$27 million negative adjustment related to prior years, recorded in the first quarter of 2005.

Income Taxes

The increase in Income Tax Expense of \$2 million is primarily due to the tax reserve adjustments, a decrease in the amortization of investment tax credits due to the sale in May 2005 of the STP nuclear plant and a decrease in consolidated tax savings from AEP, offset in part by a decrease in pretax book income.

Financial Condition**Credit Ratings**

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

| | Moody's | S&P | Fitch |
|-----------------------|----------------|----------------|--------------|
| First Mortgage Bonds | Baa1 | BBB | A |
| Senior Unsecured Debt | Baa2 | BBB | A- |

Cash Flow

Cash flows for the six months ended June 30, 2006 and 2005 were as follows:

| | 2006 | 2005 |
|---|-----------------------|-------------|
| | (in thousands) | |
| Cash and Cash Equivalents at Beginning of Period | \$ - | \$ 26 |
| Net Cash Flows From (Used For): | | |
| Operating Activities | 81,341 | (105,434) |
| Investing Activities | (121,052) | 140,683 |
| Financing Activities | 39,711 | (33,181) |
| Net Increase in Cash and Cash Equivalents | - | 2,068 |
| Cash and Cash Equivalents at End of Period | \$ - | \$ 2,094 |

Operating Activities

Net Cash Flows From Operating Activities were \$81 million in the first six months of 2006. We produced Net Income of \$21 million during the period and incurred noncash items of \$71 million for Depreciation and Amortization and \$(40) million for Carrying Costs on Stranded Cost Recovery. 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 working capital relates to a number of items; the most significant are decreases in Accounts Receivable, Net partially offset by a decrease in Accounts Payable. Accounts Receivable, Net decreased \$164 million primarily due to cash received for the retail clawback of \$61 million and 2005 storm restoration performed for non-affiliated companies of \$29 million. In addition, our removal from the SIA and CSW operating agreement resulted in fewer energy-related receivables. Accounts Payable decreased \$102 million primarily due to lower energy-related transactions resulting from our removal from the SIA and CSW Operating Agreement.

Net Cash Flows Used For Operating Activities were \$105 million in the first six months of 2005. We produced income of \$30 million during the period including noncash expense items of \$65 million for Depreciation and Amortization and \$(83) million for Deferred Income Taxes. 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 activity in these asset and liability accounts relate to a number of items; the most significant are decreases in Accounts Payable and Accrued Taxes, offset in part by a decrease in Accounts Receivable, Net. Accounts Payable decreased \$46 million while Accounts Receivable decreased \$29 million primarily due to energy-related system sales. Accounts Payable also had an additional decrease related to the sale of STP. Accrued Taxes decreased \$69 million primarily as a result of taxes remitted to the government related to prior year and current year tax accruals.

Investing Activities

Net Cash Flows Used For Investing Activities in 2006 were \$121 million primarily due to \$136 million of Construction Expenditures focused on improved service reliability projects for transmission and distribution systems.

Net Cash Flows From Investing Activities in 2005 were \$141 million primarily due to \$314 million of net proceeds from the sale of the STP nuclear plant. The proceeds were partially offset by an increase of \$107 million in Other Cash Deposits, Net related to the issuance of new pollution control revenue bonds, the proceeds which were used specifically for refinancing activities in the third quarter of 2005, and also by Construction Expenditures of \$61 million related to projects for improved transmission and distribution service reliability.

For the remainder of 2006, we expect \$150 million in Construction Expenditures.

Financing Activities

Net Cash Flows From Financing Activities in 2006 were \$40 million primarily due to the issuance of a \$125 million affiliated note with AEP. This increase in long-term debt was partially offset by a decrease in Advances from Affiliates, Net of \$54 million and the retirement of \$31 million of securitization bonds.

Net Cash Flows Used for Financing Activities in 2005 were \$33 million primarily due to the retirement of Senior Unsecured Notes Payable and Securitization Bonds of \$279 million along with payment of dividends. This was partially offset by a \$120 million increase in Advances from Affiliates, Net and issuances of pollution control bonds of \$277 million, \$120 million of which was issued for the purpose of funding the July 1, 2005 retirement of our \$120 million, 6.0% Pollution Control Bonds.

Financing Activity

Long-term debt issuances and retirements during the first six months of 2006 were:

Issuances

| Type of Debt | Principal Amount (in thousands) | Interest Rate (%) | Due Date |
|--------------------------|--|------------------------------|-----------------|
| Notes Payable-Affiliated | \$ 125,000 | 5.14 | 2007 |

Retirements

| Type of Debt | Principal Amount (in thousands) | Interest Rate (%) | Due Date |
|----------------------|--|------------------------------|-----------------|
| Securitization Bonds | \$ 30,641 | 5.01 | 2010 |

In August 2006, an affiliate issued us a 5.86%, \$70 million note due August 16, 2007.

Liquidity

We have solid investment grade ratings, which provide us ready access to capital markets in order to issue new debt or refinance long-term debt maturities. In addition, we participate in the Utility Money Pool, which provides access to AEP's liquidity.

We will use any proceeds received from the securitization (discussed below under Texas Restructuring) to pay down a portion of our equity and debt.

Summary Obligation Information

A summary of our contractual obligations is included in our 2005 Annual Report and has not changed significantly from year-end.

Significant Factors

Texas Restructuring

The PUCT issued an order in our True-up Proceeding in February 2006, which determined that our true-up regulatory asset was \$1.475 billion including carrying costs through September 2005. In December 2005, we adjusted our recorded net true-up regulatory asset to comply with the order. We appealed, seeking additional recovery consistent with the Texas Restructuring Legislation and related rules. Other parties have appealed the PUCT's order claiming it permits us to over-recover stranded costs.

We filed an application in March 2006 requesting to securitize our net stranded generation plant costs and related carrying costs through August 31, 2006. In June 2006, the PUCT approved our settlement with intervenors authorizing the securitization of \$1.697 billion of net stranded generation costs including carrying costs through August 31, 2006, the assumed securitization date, plus estimated issuance costs of \$23 million, for a total of \$1.72 billion. We anticipate issuing the securitization bonds by the end of the third quarter of 2006.

The differences between the securitization amount ordered by the PUCT of \$1.7 billion and the recorded securitizable true-up regulatory asset of \$1.5 billion at June 30, 2006 are detailed in the table below:

| | (in millions) |
|--|------------------|
| Stranded Generation Plant Costs | \$ 974 |
| Net Generation-related Regulatory Asset | 249 |
| Excess Earnings | (49) |
| Recorded Net Stranded Generation Plant Costs | 1,174 |
| Recorded Debt Carrying Costs on Net Stranded Generation Plant Costs | 375 |
| Recorded Securitizable True-up Regulatory Asset | 1,549 |
| Unrecorded But Recoverable Equity Carrying Costs | 217 |
| Unrecorded Estimated July 2006 - August 2006 Debt Carrying Costs | 17 |
| Unrecorded Excess Earnings, Related Carrying Costs and Other | 52 |
| Settlement Reduction | (77) |
| Reduction for ADITC and EDFIT Benefits | (61) |
| Approved Securitizable Amount | 1,697 |
| Unrecorded Securitization Issuance Costs | 23 |
| Amount to be Securitized | \$ 1,720 |

In June 2006, we filed to implement a CTC refund of \$355 million for our net other true-up items over eight years. The differences between the components of our Recorded Net Regulatory Liabilities for Other True-up Items as of June 30, 2006 and our CTC proceeding request are detailed below:

| | (in millions) |
|--|------------------|
| Wholesale Capacity Auction True-up | \$ 61 |
| Carrying Costs on Wholesale Capacity Auction True-up | 28 |
| Retail Clawback including Carrying Costs | (63) |
| Deferred Over-recovered Fuel Balance | (181) |
| Retrospective ADFIT Benefit | (70) |
| Other | (4) |
| Recorded Net Regulatory Liabilities - Other True-up Items | (229) |
| Unrecorded Prospective ADFIT Benefit | (240) |
| Unrecorded Estimated July 2006 - August 2006 Carrying Costs | (6) |
| Gross CTC Refund | (475) |
| FERC Jurisdictional Fuel Refund Deferral | 16 |
| ADITC and EDFIT Benefit Refund Deferral | 97 |
| Net CTC Refund Proposed, After Deferrals | (362) |
| Rate Case Expense Surcharge | 7 |
| Net Refund Proposed, After Deferrals and Expenses | \$ (355) |

We requested that a portion of the refund be deferred, pending the outcome of two contingent federal matters related to the refund of \$16 million of FERC jurisdictional fuel over-recoveries and \$97 million for potential tax normalization violation matters related to the refund of ADITC and EDFIT benefits. Although we proposed to refund the \$355 million over eight years, certain intervenors have supported accelerated refunds. Management cannot predict the outcome of this filing. If the two contingent federal matters are resolved unfavorably, we will refund the \$16 million and the \$97 million plus carrying costs.

Municipal customers and other intervenors are appealing the PUCT orders seeking to further reduce our true-up recoveries. If we determine as a result of future PUCT orders or appeal court rulings that it is probable we cannot recover a portion of our recorded net true-up regulatory asset and we are able to estimate the amount of a resultant impairment, we would record a provision for such amount which would have an adverse effect on future results of operations, cash flows and possibly financial condition. We are appealing the PUCT orders seeking relief in both state and federal court where we believe the PUCT's rulings are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law.

These appeals could take years to resolve and could result in material effects on future results of operations. If the PUCT rejects our deferral proposal and a normalization violation occurs, future results of operations and cash flows could be adversely affected by the recapture of \$105 million of our ADITC and the loss of our future accelerated tax depreciation election. The estimated future impact on earnings of the Texas restructuring as of June 30, 2006, exclusive of a possible normalization violation and any effects of appeal litigation, over the 14-year securitization net recovery period assuming the PUCT approves our CTC filing is detailed below:

| | (in millions) |
|--|------------------|
| ADITC and EDFIT Benefits Reducing Securitization | \$ 97 |

| | |
|--|-----------------|
| ADFIT Benefit Applied to Reduce 2002 Securitization of Regulatory Assets | (64) |
| Securitization Settlement | (77) |
| Unrecorded Prospective ADFIT Benefit Increasing the CTC Refund | (240) |
| Unrecorded Equity Carrying Costs Recognized as Collected | 217 |
| Future Carrying Cost Payable on Proposed CTC Refund | (113) |
| Deferred Fuel - Federal Jurisdictional Issue | 16 |
| Net Adverse Earnings Impact Over 14 Years | \$ (164) |

If the proposed CTC deferral is rejected by the PUCT or the two contingencies are refunded to customers, the future adverse impact on results of operations over the next 14 years will increase to \$317 million. This potential adverse impact on results of operations over the next 14 years would be more than offset by the annual cost of money benefit from the \$2.2 billion in net proceeds that resulted from the sale of bonds in connection with the initial regulatory asset securitization in 2002 of \$797 million and from the upcoming \$1.720 billion sale of securitization bonds later this year less the proposed \$355 million CTC refund over the next eight years.

Litigation and Regulatory Activity

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our pending litigation and regulatory proceedings, see Note 4 - Rate Matters, Note 6 - Customer Choice and Industry Restructuring and Note 7 - Commitments and Contingencies in our 2005 Annual Report. Also, see Note 3 - Rate Matters, Note 4 - Customer Choice and Industry Restructuring and Note 5 - Commitments and Contingencies in the "Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries" section. An adverse result in these proceedings has the potential to materially affect our results of operations, financial condition and cash flows.

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

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2005 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES**Market Risks**

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

MTM Risk Management Contract Net Assets

Our MTM Risk Management Contract Net Assets are zero as of June 30, 2006. For further explanation, see "Allocating Agreement between AEP East companies and AEP West companies" section of this Management's Financial Discussion and Analysis.

The following table summarizes the reasons for changes in our total MTM value as compared to December 31, 2005.

MTM Risk Management Contract Net Assets
Six Months Ended June 30, 2006
(in thousands)

| | | |
|---|----|---------|
| Total MTM Risk Management Contract Net Assets at December 31, 2005 | \$ | 5,426 |
| (Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period | | (1,362) |
| Fair Value of New Contracts at Inception When Entered During the Period (a) | | - |
| Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period | | - |
| Changes in Fair Value Due to Valuation Methodology Changes on Forward Contracts | | - |
| Changes in Fair Value Due to Market Fluctuations During the Period (b) | | (3,681) |
| Changes Due to SIA and CSW Operating Agreement (c) | | (383) |
| Changes in Fair Value Allocated to Regulated Jurisdictions (d) | | - |
| Total MTM Risk Management Contract Net Assets | | - |
| Net Cash Flow Hedge Contracts | | - |
| Total MTM Risk Management Contract Net Assets at June 30, 2006 | \$ | - |

- (a) 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.
- (b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
- (c) See "Allocating Agreement between AEP East companies and AEP West companies" section of this Management's Financial Discussion and Analysis.
- (d) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

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

Our net MTM Risk Management Contracts are zero as of June 30, 2006. Therefore, there is no maturity and source of fair value to report.

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

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

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Condensed Consolidated Balance Sheets and the reasons for the changes from December 31, 2005 to June 30, 2006. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity Six Months Ended June 30, 2006 (in thousands)

| | Power |
|--|--------------|
| Beginning Balance in AOCI December 31, 2005 | \$ (224) |
| Changes in Fair Value | - |
| Impact Due to Changes in SIA (a) | 218 |
| Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled | 6 |
| Ending Balance in AOCI June 30, 2006 | \$ - |

(a) See "Allocating Agreement between AEP East companies and AEP West companies" section of this Management's Financial Discussion and Analysis.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is zero.

Credit Risk

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

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at June 30, 2006, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

| | Six Months Ended June 30, 2006 (in thousands) | | | | Twelve Months Ended December 31, 2005 (in thousands) | | | |
|--|--|-------------|----------------|------------|---|-------------|----------------|------------|
| | End | High | Average | Low | End | High | Average | Low |
| | \$- | \$11 | \$3 | \$- | \$111 | \$184 | \$88 | \$32 |

VaR Associated with Debt Outstanding

We also utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was \$94 million and \$93 million at June 30, 2006 and December 31, 2005, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

| | Three Months Ended | | Six Months Ended | |
|---|---------------------------|------------------|-------------------------|------------------|
| | 2006 | 2005 | 2006 | 2005 |
| REVENUES | | | | |
| Electric Generation, Transmission and Distribution | \$ 149,688 | \$ 184,743 | \$ 272,899 | \$ 366,890 |
| Sales to AEP Affiliates | 1,546 | 5,302 | 3,144 | 10,266 |
| Other - Nonaffiliated | 10,255 | 12,281 | 20,734 | 26,527 |
| TOTAL | 161,489 | 202,326 | 296,777 | 403,683 |
| EXPENSES | | | | |
| Fuel and Other Consumables for Electric Generation | 996 | 4,034 | 2,722 | 10,132 |
| Purchased Electricity for Resale | 1,152 | 9,996 | 2,832 | 25,366 |
| Other Operation | 63,257 | 76,584 | 122,184 | 157,333 |
| Maintenance | 8,787 | 12,433 | 16,576 | 29,472 |
| Depreciation and Amortization | 37,215 | 35,434 | 70,550 | 64,720 |
| Taxes Other Than Income Taxes | 16,671 | 20,923 | 37,034 | 43,454 |
| TOTAL | 128,078 | 159,404 | 251,898 | 330,477 |
| OPERATING INCOME | 33,411 | 42,922 | 44,879 | 73,206 |
| Other Income (Expense): | | | | |
| Interest Income | 527 | 5,929 | 1,032 | 7,427 |
| Carrying Costs Income | 20,413 | 19,938 | 39,836 | 14,797 |
| Allowance for Equity Funds Used During Construction | 631 | 149 | 1,004 | 700 |
| Interest Expense | (29,882) | (32,642) | (56,655) | (59,721) |
| INCOME BEFORE INCOME TAXES | 25,100 | 36,296 | 30,096 | 36,409 |
| Income Tax Expense | 8,125 | 7,928 | 9,348 | 6,904 |
| NET INCOME | 16,975 | 28,368 | 20,748 | 29,505 |
| Preferred Stock Dividend Requirements | 61 | 61 | 121 | 121 |
| EARNINGS APPLICABLE TO COMMON STOCK | \$ 16,914 | \$ 28,307 | \$ 20,627 | \$ 29,384 |

The common stock of TCC is owned by a wholly-owned subsidiary of AEP.

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

| | Common Stock | Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total |
|--|-----------------|--------------------|----------------------|--|--------------|
| DECEMBER 31, 2004 | \$ 55,292 | \$ 132,606 | \$ 1,084,904 | \$ (4,159) | \$ 1,268,643 |
| Common Stock Dividends | | | (150,000) | | (150,000) |
| Preferred Stock Dividends | | | (121) | | (121) |
| TOTAL | | | | | 1,118,522 |
| COMPREHENSIVE INCOME | | | | | |
| Other Comprehensive Loss, Net of Taxes: | | | | | |
| Cash Flow Hedges, Net of Tax of \$546 | | | | (1,014) | (1,014) |
| NET INCOME | | | 29,505 | | 29,505 |
| TOTAL COMPREHENSIVE INCOME | | | | | 28,491 |
| JUNE 30, 2005 | \$ 55,292 | \$ 132,606 | \$ 964,288 | \$ (5,173) | \$ 1,147,013 |
| DECEMBER 31, 2005 | \$ 55,292 | \$ 132,606 | \$ 760,884 | \$ (1,152) | \$ 947,630 |
| Preferred Stock Dividends | | | (121) | | (121) |
| TOTAL | | | | | 947,509 |
| COMPREHENSIVE INCOME | | | | | |
| Other Comprehensive Income, Net of Taxes: | | | | | |
| Cash Flow Hedges, Net of Tax of \$121 | | | | 224 | 224 |
| NET INCOME | | | 20,748 | | 20,748 |
| TOTAL COMPREHENSIVE INCOME | | | | | 20,972 |
| JUNE 30, 2006 | \$ 55,292 | \$ 132,606 | \$ 781,511 | \$ (928) | \$ 968,481 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

**AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED BALANCE SHEETS**

ASSETS

June 30, 2006 and December 31, 2005

(in thousands)

(Unaudited)

| | 2006 | 2005 |
|---|---------------------|---------------------|
| CURRENT ASSETS | | |
| Cash and Cash Equivalents | \$ - | \$ - |
| Other Cash Deposits | 57,456 | 66,153 |
| Accounts Receivable: | | |
| Customers | 64,155 | 209,957 |
| Affiliated Companies | 4,002 | 23,486 |
| Accrued Unbilled Revenues | 26,481 | 25,606 |
| Allowance for Uncollectible Accounts | (185) | (143) |
| Total Accounts Receivable | 94,453 | 258,906 |
| Unbilled Construction Costs | 13,177 | 19,440 |
| Materials and Supplies | 20,951 | 13,897 |
| Risk Management Assets | - | 14,311 |
| Prepayments and Other | 6,822 | 5,231 |
| TOTAL | 192,859 | 377,938 |
| PROPERTY, PLANT AND EQUIPMENT | | |
| Electric: | | |
| Transmission | 892,979 | 817,351 |
| Distribution | 1,543,035 | 1,476,683 |
| Other | 229,915 | 233,361 |
| Construction Work in Progress | 97,407 | 129,800 |
| Total | 2,763,336 | 2,657,195 |
| Accumulated Depreciation and Amortization | 627,669 | 636,078 |
| TOTAL - NET | 2,135,667 | 2,021,117 |
| OTHER NONCURRENT ASSETS | | |
| Regulatory Assets | 1,688,536 | 1,688,787 |
| Securitized Transition Assets | 572,157 | 593,401 |
| Long-term Risk Management Assets | - | 11,609 |
| Employee Benefits and Pension Assets | 113,299 | 114,733 |
| Deferred Charges and Other | 67,292 | 53,011 |
| TOTAL | 2,441,284 | 2,461,541 |
| Assets Held for Sale - Texas Generation Plants | 45,608 | 44,316 |
| TOTAL ASSETS | \$ 4,815,418 | \$ 4,904,912 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
June 30, 2006 and December 31, 2005
(Unaudited)

| | 2006 | 2005 |
|--|---------------------|---------------------|
| | (in thousands) | |
| CURRENT LIABILITIES | | |
| Advances from Affiliates | \$ 27,926 | \$ 82,080 |
| Accounts Payable: | | |
| General | 32,661 | 82,666 |
| Affiliated Companies | 16,960 | 65,574 |
| Long-term Debt Due Within One Year - Nonaffiliated | 154,384 | 152,900 |
| Risk Management Liabilities | - | 13,024 |
| Accrued Taxes | 50,221 | 54,566 |
| Accrued Interest | 31,767 | 32,497 |
| Other | 26,606 | 45,927 |
| TOTAL | 340,525 | 529,234 |
| NONCURRENT LIABILITIES | | |
| Long-term Debt - Nonaffiliated | 1,518,580 | 1,550,596 |
| Long-term Debt - Affiliated | 275,000 | 150,000 |
| Long-term Risk Management Liabilities | - | 7,857 |
| Deferred Income Taxes | 1,014,520 | 1,048,372 |
| Regulatory Liabilities and Deferred Investment Tax Credits | 674,269 | 652,143 |
| Deferred Credits and Other | 18,104 | 13,140 |
| TOTAL | 3,500,473 | 3,422,108 |
| TOTAL LIABILITIES | 3,840,998 | 3,951,342 |
| Cumulative Preferred Stock Not Subject to Mandatory Redemption | 5,939 | 5,940 |
| Commitments and Contingencies (Note 5) | | |
| COMMON SHAREHOLDER'S EQUITY | | |
| Common Stock - \$25 Par Value Per Share: | | |
| Authorized - 12,000,000 Shares | | |
| Outstanding - 2,211,678 Shares | 55,292 | 55,292 |
| Paid-in Capital | 132,606 | 132,606 |
| Retained Earnings | 781,511 | 760,884 |
| Accumulated Other Comprehensive Income (Loss) | (928) | (1,152) |
| TOTAL | 968,481 | 947,630 |
| TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY | \$ 4,815,418 | \$ 4,904,912 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

| | 2006 | 2005 |
|--|------------------|------------------|
| OPERATING ACTIVITIES | | |
| Net Income | \$ 20,748 | \$ 29,505 |
| Adjustments for Noncash Items: | | |
| Depreciation and Amortization | 70,550 | 64,720 |
| Accretion of Asset Retirement Obligations | 37 | 7,549 |
| Deferred Income Taxes | 6,095 | (83,369) |
| Carrying Costs on Stranded Cost Recovery | (39,836) | (14,797) |
| Mark-to-Market of Risk Management Contracts | 5,426 | 7,085 |
| Over/Under Fuel Recovery | 3,908 | (2,400) |
| Deferred Property Taxes | (16,592) | (15,450) |
| Change in Other Noncurrent Assets | 21,686 | (1,908) |
| Change in Other Noncurrent Liabilities | (25,338) | 9 |
| Changes in Components of Working Capital: | | |
| Accounts Receivable, Net | 164,453 | 28,976 |
| Fuel, Materials and Supplies | (7,652) | (969) |
| Accounts Payable | (102,422) | (45,594) |
| Accrued Taxes, Net | (9,596) | (69,046) |
| Customer Deposits | (6,876) | (733) |
| Accrued Interest | (730) | (2,555) |
| Other Current Assets | 9,924 | (8,279) |
| Other Current Liabilities | (12,444) | 1,822 |
| Net Cash Flows From (Used For) Operating Activities | 81,341 | (105,434) |
| INVESTING ACTIVITIES | | |
| Construction Expenditures | (136,475) | (60,972) |
| Change in Other Cash Deposits, Net | 9,340 | (107,494) |
| Purchases of Investment Securities | - | (154,364) |
| Sales of Investment Securities | - | 149,804 |
| Proceeds from Sale of Assets | 6,083 | 313,709 |
| Net Cash Flows From (Used For) Investing Activities | (121,052) | 140,683 |
| FINANCING ACTIVITIES | | |
| Issuance of Long-term Debt - Nonaffiliated | - | 276,690 |
| Issuance of Long-term Debt - Affiliated | 125,000 | - |
| Change in Advances from Affiliates, Net | (54,154) | 119,857 |
| Retirement of Long-term Debt | (30,641) | (279,386) |
| Retirement of Preferred Stock | (1) | - |
| Principal Payments for Capital Lease Obligations | (372) | (221) |
| Dividends Paid on Cumulative Preferred Stock | (121) | (121) |
| Dividends Paid on Common Stock | - | (150,000) |
| Net Cash From (Used For) Financing Activities | 39,711 | (33,181) |

| | | |
|---|------|----------|
| Net Increase in Cash and Cash Equivalents | - | 2,068 |
| Cash and Cash Equivalents at Beginning of Period | - | 26 |
| Cash and Cash Equivalents at End of Period | \$ - | \$ 2,094 |

SUPPLEMENTAL DISCLOSURE

| | | |
|--|-----------|-----------|
| Cash Paid for Interest, Net of Capitalized Amounts | \$ 51,577 | \$ 52,441 |
| Cash Paid for Income Taxes, Net of Refunds | 13,440 | 161,372 |
| Noncash Acquisitions Under Capital Leases | 2,145 | 261 |
| Construction Expenditures Included in Accounts Payable at June 30, | 14,840 | 3,970 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries .

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARY
INDEX TO CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT
SUBSIDIARIES

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

| | Footnote Reference |
|--|-------------------------------|
| Significant Accounting Matters | Note 1 |
| New Accounting Pronouncements | Note 2 |
| Rate Matters | Note 3 |
| Customer Choice and Industry Restructuring | Note 4 |
| Commitments and Contingencies | Note 5 |
| Guarantees | Note 6 |
| Company-wide Staffing and Budget Review | Note 7 |
| Assets Held for Sale | Note 8 |
| Benefit Plans | Note 9 |
| Income Taxes | Note 10 |
| Business Segments | Note 11 |
| Financing Activities | Note 12 |

AEP TEXAS NORTH COMPANY

AEP TEXAS NORTH COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

Allocation Agreement between AEP East companies and AEP West companies

Under the Texas Restructuring Legislation, we are completing the final stage of exiting the generation business and have ceased serving retail load. Based on the corporate separation and generation divestiture activities underway, the nature of our business is no longer compatible with our participation in the CSW Operating Agreement and the SIA since these agreements involve the coordinated planning and operation of power supply facilities. Accordingly, on behalf of the AEP East companies and the AEP West companies, AEPSC filed with the FERC to remove us from those agreements. The FERC approved the filing in March 2006. The SIA includes a methodology for sharing trading and marketing margins among the AEP East companies and the AEP West companies. Therefore, our sharing of margins under the CSW Operating Agreement and the SIA ceased effective May 1, 2006, which affects our future results of operations and cash flows. We will continue to have margin and collateral deposits, risk management assets and liabilities and trading gains or losses to the extent that we have contracts dedicated specifically to us.

Results of Operations

Second Quarter of 2006 Compared to Second Quarter of 2005

Reconciliation of Second Quarter of 2005 to Second Quarter of 2006 Net Income (Loss)
(in millions)

| | | |
|---|-----------|-------------|
| Second Quarter of 2005 | \$ | 12 |
| Changes in Gross Margin: | | |
| Texas Supply | (14) | |
| Texas Wires | (1) | |
| Off-system Sales | (2) | |
| Transmission Revenues | (3) | |
| Other | (3) | |
| Total Change in Gross Margin | | (23) |
| Changes in Operating Expenses and Other: | | |
| Other Operation and Maintenance | | 3 |
| Income Tax Expense | | 7 |
| Second Quarter of 2006 | \$ | (1) |

Net Income decreased \$13 million in the second quarter of 2006 primarily due to a decrease in Gross Margin of \$23 million partially offset by a reduction in Other Operation and Maintenance expenses of \$3 million.

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

- Texas Supply margins decreased \$14 million primarily due to a \$19 million decrease in dedicated ERCOT energy sales, offset by \$9 million of lower fuel and purchased power costs. This decrease in Texas Supply margins was affected by increased generation outages and

market conditions within ERCOT.

- Transmission Revenues decreased \$3 million primarily due to reduced affiliated transmission fees resulting from the elimination of the affiliated OATT.
- Other revenues decreased \$3 million primarily due to the completion of certain third party construction projects, primarily related to work performed for the Lower Colorado River Authority.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased \$3 million primarily due to lower expenses related to the completion of certain third party construction projects, primarily related to work performed for the Lower Colorado River Authority.

Income Taxes

The decrease in Income Tax Expense of \$7 million is primarily due to a decrease in pretax book income.

Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2005

Reconciliation of Six Months Ended June 30, 2005 to Six Months Ended June 30, 2006 Net Income (in millions)

| | | |
|---|------|------|
| Six Months Ended June 30, 2005 | \$ | 19 |
| Changes in Gross Margin: | | |
| Texas Supply | (17) | |
| Texas Wires | (1) | |
| Off-system Sales | (1) | |
| Transmission Revenues | (5) | |
| Other | (40) | |
| Total Change in Gross Margin | | (64) |
| Changes in Operating Expenses and Other: | | |
| Other Operation and Maintenance | 37 | |
| Interest Expense | 1 | |
| Total Change in Operating Expenses and Other | | 38 |
| Income Tax Expense | | 10 |
| Six Months Ended June 30, 2006 | \$ | 3 |

Net Income decreased \$16 million in the first six months of 2006 primarily due to a decrease in Gross Margin of \$64 million partially offset by a reduction in Other Operation and Maintenance expenses of \$37 million.

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

- Texas Supply margins decreased \$17 million primarily due to a \$25 million decrease in dedicated ERCOT energy sales, offset by \$12 million of lower fuel and purchased power costs. This decrease in Texas Supply margins was affected by increased generation outages and market conditions within ERCOT.

- Transmission Revenues decreased \$5 million primarily due to reduced affiliated transmission fees resulting from the elimination of the affiliated OATT.
- Other revenues decreased \$40 million primarily resulting from the completion of certain third party construction projects, primarily related to work performed for the Lower Colorado River Authority.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased \$37 million primarily due to lower expenses related to the completion of certain third party construction projects, primarily related to work performed for the Lower Colorado River Authority.

Income Taxes

The decrease in Income Tax Expense of \$10 million is primarily due to a decrease in pretax book income.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook, except for Fitch which moved us to negative outlook. Our current ratings are as follows:

| | Moody's | S&P | Fitch |
|-----------------------|----------------|----------------|--------------|
| First Mortgage Bonds | A3 | BBB | A |
| Senior Unsecured Debt | Baa1 | BBB | A- |

Financing Activity

There were no long-term debt issuances or retirements during the first six months of 2006.

Liquidity

We have solid investment grade ratings, which provide us ready access to capital markets in order to issue new debt or refinance long-term debt maturities. In addition, we participate in the Utility Money Pool, which provides access to AEP's liquidity.

Summary Obligation Information

A summary of our contractual obligations is included in our 2005 Annual Report and has not changed significantly from year-end except for Energy and Capacity Purchase Contracts. We exited both the SIA and CSW Operating Agreement eliminating our future obligation in Energy and Capacity Purchase Contracts. See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section within Note 3 - Rate Matters.

Significant Factors

Litigation and Regulatory Activity

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our pending litigation and regulatory proceedings, see Note 4 - Rate Matters, Note 6 - Customer Choice and Industry Restructuring and Note 7 - Commitments and Contingencies in our 2005 Annual Report. Also, see Note 3 - Rate Matters, Note 4 - Customer Choice and Industry Restructuring and Note 5 - Commitments and Contingencies in the "Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries" section. An adverse result in these proceedings has the potential to materially affect our results of operations, financial condition and cash flows.

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

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2005 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES**Market Risks**

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

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our condensed balance sheet as of June 30, 2006 and the reasons for changes in our total MTM value as compared to December 31, 2005.

**Reconciliation of MTM Risk Management Contracts to
Condensed Balance Sheet
As of June 30, 2006
(in thousands)**

| | MTM Risk Management Contracts | Cash Flow Hedges | Total |
|--|--|-----------------------------|--------------|
| Current Assets | \$ - | \$ 552 | \$ 552 |
| Noncurrent Assets | - | 4,027 | 4,027 |
| Total MTM Derivative Contract Assets | - | 4,579 | 4,579 |
| Current Liabilities | - | (843) | (843) |
| Noncurrent Liabilities | - | - | - |
| Total MTM Derivative Contract Liabilities | - | (843) | (843) |
| Total MTM Derivative Contract Net Assets | \$ - | \$ 3,736 | \$ 3,736 |

**MTM Risk Management Contract Net Assets
Six Months Ended June 30, 2006
(in thousands)**

| | |
|---|----------|
| Total MTM Risk Management Contract Net Assets at December 31, 2005 | \$ 2,698 |
| (Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period | (678) |
| Fair Value of New Contracts at Inception When Entered During the Period (a) | - |
| Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period | - |
| Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts | - |
| Changes in Fair Value Due to Market Fluctuations During the Period (b) | (1,206) |
| Changes Due to SIA and CSW Operating Agreement (c) | (814) |
| Changes in Fair Value Allocated to Regulated Jurisdictions (d) | - |
| Total MTM Risk Management Contract Net Assets | - |
| Net Cash Flow Hedge Contracts | 3,736 |
| Total MTM Risk Management Contract Net Assets at June 30, 2006 | \$ 3,736 |

(a) 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.

- (b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
- (c) See “Allocation Agreement between AEP East companies and AEP West companies” section of this Management's Financial Discussion and Analysis.
- (d) “Changes in Fair Value Allocated to Regulated Jurisdictions” relates to the net gains (losses) of those contracts that are not reflected in the Condensed Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

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

Our MTM Risk Management Contract Net Assets are zero as of June 30, 2006. Therefore, there is no Maturity and Source of Fair Value to report.

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

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

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Condensed Balance Sheets and the reasons for the changes from December 31, 2005 to June 30, 2006. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity Six Months Ended June 30, 2006 (in thousands)

| | Power |
|--|-----------------|
| Beginning Balance in AOCI December 31, 2005 | \$ (111) |
| Changes in Fair Value | 2,429 |
| Impact Due to Change in SIA (a) | 98 |
| Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled | 13 |
| Ending Balance in AOCI June 30, 2006 | \$ 2,429 |

- (a) See “Allocating Agreement between AEP East companies and AEP West companies” section of this Management’s Financial Discussion and Analysis.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a \$189 thousand loss.

Credit Risk

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

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at June 30, 2006, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

| Six Months Ended June 30, 2006 (in thousands) | | | | Twelve Months Ended December 31, 2005 (in thousands) | | | |
|--|-------------|----------------|------------|---|-------------|----------------|------------|
| End | High | Average | Low | End | High | Average | Low |
| \$- | \$23 | \$6 | \$- | \$55 | \$92 | \$44 | \$16 |

VaR Associated with Debt Outstanding

We also utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was \$15 million and \$13 million at June 30, 2006 and December 31, 2005, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or financial position.

AEP TEXAS NORTH COMPANY
CONDENSED STATEMENTS OF OPERATIONS
For the Three and Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

| | Three Months Ended | | Six Months Ended | |
|---|--------------------|------------------|------------------|------------------|
| | 2006 | 2005 | 2006 | 2005 |
| REVENUES | | | | |
| Electric Generation, Transmission and Distribution | \$ 71,051 | \$ 97,199 | \$ 139,876 | \$ 169,088 |
| Sales to AEP Affiliates | 11,860 | 12,880 | 17,885 | 24,170 |
| Other | 87 | 4,625 | (97) | 40,353 |
| TOTAL | 82,998 | 114,704 | 157,664 | 233,611 |
| EXPENSES | | | | |
| Fuel and Other Consumables for Electric Generation | 7,044 | 11,356 | 19,159 | 24,339 |
| Purchased Electricity for Resale | 32,883 | 37,604 | 47,279 | 53,964 |
| Other Operation | 21,633 | 24,587 | 40,189 | 78,257 |
| Maintenance | 5,216 | 4,920 | 10,417 | 9,139 |
| Depreciation and Amortization | 10,182 | 10,362 | 20,405 | 20,517 |
| Taxes Other Than Income Taxes | 5,856 | 5,713 | 11,396 | 11,418 |
| TOTAL | 82,814 | 94,542 | 148,845 | 197,634 |
| OPERATING INCOME | 184 | 20,162 | 8,819 | 35,977 |
| Other Income (Expense): | | | | |
| Interest Income | 120 | 542 | 339 | 798 |
| Allowance for Equity Funds Used During Construction | 108 | 156 | 490 | 229 |
| Interest Expense | (4,517) | (4,869) | (8,879) | (9,853) |
| INCOME (LOSS) BEFORE INCOME TAXES | (4,105) | 15,991 | 769 | 27,151 |
| Income Tax Expense (Credit) | (3,513) | 3,987 | (2,473) | 7,753 |
| NET INCOME (LOSS) | (592) | 12,004 | 3,242 | 19,398 |
| Preferred Stock Dividend Requirements | 26 | 26 | 52 | 52 |
| Gain on Reacquired Preferred Stock | - | - | 2 | - |
| EARNINGS (LOSS) APPLICABLE TO COMMON STOCK | \$ (618) | \$ 11,978 | \$ 3,192 | \$ 19,346 |

T The common stock of TNC is owned by a wholly-owned subsidiary of AEP.

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

| | Common Stock | Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total |
|--|-----------------|--------------------|----------------------|--|----------------|
| DECEMBER 31, 2004 | \$ 137,214 | \$ 2,351 | \$ 170,984 | \$ (128) | \$ 310,421 |
| Common Stock Dividends | | | (12,626) | | (12,626) |
| Preferred Stock Dividends | | | (52) | | (52) |
| TOTAL | | | | | 297,743 |
| COMPREHENSIVE INCOME | | | | | |
| Other Comprehensive Loss, Net of Taxes: | | | | | |
| Cash Flow Hedges, Net of Tax of \$236 | | | | (439) | (439) |
| NET INCOME | | | 19,398 | | 19,398 |
| TOTAL COMPREHENSIVE INCOME | | | | | 18,959 |
| JUNE 30, 2005 | \$ 137,214 | \$ 2,351 | \$ 177,704 | \$ (567) | \$ 316,702 |
| DECEMBER 31, 2005 | \$ 137,214 | \$ 2,351 | \$ 174,858 | \$ (504) | \$ 313,919 |
| Common Stock Dividends | | | (12,750) | | (12,750) |
| Preferred Stock Dividends | | | (52) | | (52) |
| Gain on Reacquired Preferred Stock | | | 2 | | 2 |
| TOTAL | | | | | 301,119 |
| COMPREHENSIVE INCOME | | | | | |
| Other Comprehensive Income, Net of Taxes: | | | | | |
| Cash Flow Hedges, Net of Tax of \$1,368 | | | | 2,540 | 2,540 |
| NET INCOME | | | 3,242 | | 3,242 |
| TOTAL COMPREHENSIVE INCOME | | | | | 5,782 |
| JUNE 30, 2006 | \$ 137,214 | \$ 2,351 | \$ 165,300 | \$ 2,036 | \$ 306,901 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

**AEP TEXAS NORTH COMPANY
CONDENSED BALANCE SHEETS**

ASSETS

June 30, 2006 and December 31, 2005

(in thousands)

(Unaudited)

| | 2006 | 2005 |
|---|-------------------|---------------------|
| CURRENT ASSETS | | |
| Cash and Cash Equivalents | \$ - | \$ - |
| Other Cash Deposits | 8,993 | 1,432 |
| Advances to Affiliates | - | 34,286 |
| Accounts Receivable: | | |
| Customers | 24,702 | 77,678 |
| Affiliated Companies | 8,176 | 26,149 |
| Accrued Unbilled Revenues | 4,383 | 5,016 |
| Allowance for Uncollectible Accounts | (23) | (18) |
| Total Accounts Receivable | 37,238 | 108,825 |
| Fuel | 7,000 | 2,636 |
| Materials and Supplies | 7,743 | 6,858 |
| Risk Management Assets | 552 | 7,114 |
| Prepayments and Other | 3,665 | 3,772 |
| TOTAL | 65,191 | 164,923 |
| PROPERTY, PLANT AND EQUIPMENT | | |
| Electric: | | |
| Production | 290,261 | 288,934 |
| Transmission | 324,294 | 289,029 |
| Distribution | 502,917 | 492,878 |
| Other | 164,500 | 167,849 |
| Construction Work in Progress | 23,223 | 46,424 |
| Total | 1,305,195 | 1,285,114 |
| Accumulated Depreciation and Amortization | 479,043 | 478,519 |
| TOTAL - NET | 826,152 | 806,595 |
| OTHER NONCURRENT ASSETS | | |
| Regulatory Assets | 9,078 | 9,787 |
| Long-term Risk Management Assets | 4,027 | 5,772 |
| Employee Benefits and Pension Assets | 45,702 | 46,289 |
| Deferred Charges and Other | 10,930 | 10,468 |
| TOTAL | 69,737 | 72,316 |
| TOTAL ASSETS | \$ 961,080 | \$ 1,043,834 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
June 30, 2006 and December 31, 2005
(Unaudited)

| | 2006 | 2005 |
|--|-------------------|---------------------|
| | (in thousands) | |
| CURRENT LIABILITIES | | |
| Advances from Affiliates | \$ 6,005 | \$ - |
| Accounts Payable: | | |
| General | 13,767 | 19,739 |
| Affiliated Companies | 27,450 | 84,923 |
| Long-term Debt Due Within One Year - Nonaffiliated | 8,151 | - |
| Risk Management Liabilities | 843 | 6,475 |
| Accrued Taxes | 19,904 | 21,212 |
| Other | 11,926 | 21,050 |
| TOTAL | 88,046 | 153,399 |
| NONCURRENT LIABILITIES | | |
| Long-term Debt - Nonaffiliated | 268,739 | 276,845 |
| Long-term Risk Management Liabilities | - | 3,906 |
| Deferred Income Taxes | 127,114 | 132,335 |
| Regulatory Liabilities and Deferred Investment Tax Credits | 146,653 | 139,732 |
| Deferred Credits and Other | 21,278 | 21,341 |
| TOTAL | 563,784 | 574,159 |
| TOTAL LIABILITIES | 651,830 | 727,558 |
| Cumulative Preferred Stock Not Subject to Mandatory Redemption | 2,349 | 2,357 |
| Commitments and Contingencies (Note 5) | | |
| COMMON SHAREHOLDER'S EQUITY | | |
| Common Stock - \$25 Par Value Per Share: | | |
| Authorized - 7,800,000 Shares | | |
| Outstanding - 5,488,560 Shares | 137,214 | 137,214 |
| Paid-in Capital | 2,351 | 2,351 |
| Retained Earnings | 165,300 | 174,858 |
| Accumulated Other Comprehensive Income (Loss) | 2,036 | (504) |
| TOTAL | 306,901 | 313,919 |
| TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY | \$ 961,080 | \$ 1,043,834 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

| | 2006 | 2005 |
|---|----------------|-----------------|
| OPERATING ACTIVITIES | | |
| Net Income | \$ 3,242 | \$ 19,398 |
| Adjustments for Noncash Items: | | |
| Depreciation and Amortization | 20,405 | 20,517 |
| Deferred Income Taxes | (3,183) | (1,742) |
| Mark-to-Market of Risk Management Contracts | 2,698 | 3,062 |
| Deferred Property Taxes | (8,408) | (8,145) |
| Change in Other Noncurrent Assets | (3,302) | (1,937) |
| Change in Other Noncurrent Liabilities | 1,904 | 2,202 |
| Changes in Components of Working Capital: | | |
| Accounts Receivable, Net | 71,587 | 4,654 |
| Fuel, Materials and Supplies | (5,249) | (2,495) |
| Accounts Payable | (62,323) | 11,893 |
| Accrued Taxes, Net | (4,046) | (11,847) |
| Customer Deposits | (3,571) | (388) |
| Other Current Assets | 2,845 | 14,577 |
| Other Current Liabilities | (4,582) | (710) |
| Net Cash Flows From Operating Activities | 8,017 | 49,039 |
| INVESTING ACTIVITIES | | |
| Construction Expenditures | (36,675) | (24,177) |
| Change in Other Cash Deposits, Net | 1,073 | - |
| Change In Advances to Affiliates, Net | 34,286 | (12,161) |
| Proceeds from Sale of Assets | 250 | 1,033 |
| Net Cash Flows Used For Investing Activities | (1,066) | (35,305) |
| FINANCING ACTIVITIES | | |
| Change in Advances from Affiliates, Net | 6,005 | - |
| Retirement of Preferred Stock | (6) | - |
| Principal Payments for Capital Lease Obligations | (148) | (118) |
| Dividends Paid on Common Stock | (12,750) | (12,626) |
| Dividends Paid on Cumulative Preferred Stock | (52) | (52) |
| Net Cash Flows Used For Financing Activities | (6,951) | (12,796) |
| Net Increase in Cash and Cash Equivalents | - | 938 |
| Cash and Cash Equivalents at Beginning of Period | - | - |
| Cash and Cash Equivalents at End of Period | \$ - | \$ 938 |
| SUPPLEMENTAL DISCLOSURE | | |
| Cash Paid for Interest, Net of Capitalized Amounts | \$ 7,809 | \$ 9,014 |
| Cash Paid for Income Taxes, Net of Refunds | 6,079 | 21,865 |
| Noncash Acquisitions Under Capital Leases | 749 | 171 |
| | 2,037 | 1,726 |

Construction Expenditures Included in Accounts
Payable at June 30,

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

AEP TEXAS NORTH COMPANY
INDEX TO CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT
SUBSIDIARIES

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

| | Footnote Reference |
|--|-------------------------------|
| Significant Accounting Matters | Note 1 |
| New Accounting Pronouncements | Note 2 |
| Rate Matters | Note 3 |
| Customer Choice and Industry Restructuring | Note 4 |
| Commitments and Contingencies | Note 5 |
| Guarantees | Note 6 |
| Company-wide Staffing and Budget Review | Note 7 |
| Benefit Plans | Note 9 |
| Income Taxes | Note 10 |
| Business Segments | Note 11 |
| Financing Activities | Note 12 |

**APPALACHIAN POWER COMPANY
AND SUBSIDIARIES**

**APPALACHIAN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS**

Results of Operations

Second Quarter of 2006 Compared to Second Quarter of 2005

**Reconciliation of Second Quarter of 2005 to Second Quarter of 2006 Net Income
(in millions)**

| | | |
|---|-----------|-------------|
| Second Quarter of 2005 | \$ | 24 |
| Changes in Gross Margin: | | |
| Retail Margins | 5 | |
| Off-system Sales | 1 | |
| Transmission Revenues | (17) | |
| Other | (1) | |
| Total Change in Gross Margin | | (12) |
| Changes in Operating Expenses and Other: | | |
| Other Operation and Maintenance | (10) | |
| Depreciation and Amortization | (2) | |
| Taxes Other Than Income Taxes | 1 | |
| Carrying Costs Income | 4 | |
| Interest Expense | (4) | |
| Other Income | 4 | |
| Total Change in Operating Expenses and Other | | (7) |
| Income Tax Expense | | 5 |
| Second Quarter of 2006 | \$ | 10 |

Net Income decreased \$14 million to \$10 million in 2006. The key drivers of the decrease were a \$12 million net decrease in Gross Margin and a \$7 million net increase in Operating Expenses and Other, offset by a \$5 million decrease in Income Tax Expense.

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

- Retail Margins increased \$5 million in comparison to 2005 primarily due to an \$8 million reduction in capacity settlement payments under the Interconnection Agreement due to our lower member load ratio (MLR) share and our increased capacity, an \$8 million increase in revenues related to financial transmission rights, net of congestion, and a \$7 million increase in retail revenues primarily related to two new industrial customers. The increase in financial transmission rights revenue is due to improved management of price risk related to serving retail load under current transmission constraints. These increases were partially offset by a \$15 million decline in fuel margins caused primarily by higher fuel costs.

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Transmission Revenues decreased \$17 million primarily due to the elimination of SECA revenues as of April 1, 2006 and a \$5 million provision for potential SECA refunds pending settlement negotiations with various intervenors. See the "SECA Revenue Subject to Refund" section of Note 3 - Rate Matters.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased \$10 million mainly due to a \$5 million increase in planned maintenance outages and an increase of \$4 million related to increased expenses for overhead line right-of-way clearing and overhead line repairs.
- Carrying Costs Income increased \$4 million primarily due to the establishment of a regulatory asset for carrying costs related to the Virginia environmental and reliability costs incurred.
- Interest Expense increased \$4 million primarily due to long-term debt issuances in 2006, partially offset by an increase in allowance for borrowed funds used during construction.
- Other Income increased \$4 million primarily due to interest income related to an increase in Advances to Affiliates.

Income Taxes

The decrease in Income Tax Expense of \$5 million is primarily due to a decrease in pretax book income and changes in certain book/tax differences accounted for on a flow-through basis, offset in part by an increase in state income taxes.

Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2005

**Reconciliation of Six Months Ended June 30, 2005 to Six Months Ended June 30, 2006 Net Income
(in millions)**

| | |
|---|--------------|
| Six Months Ended June 30, 2005 | \$ 71 |
| Changes in Gross Margin: | |
| Retail Margins | 33 |
| Transmission Revenues | (16) |
| Other | 1 |
| Total Change in Gross Margin | 18 |
| Changes in Operating Expenses and Other: | |
| Other Operation and Maintenance | 3 |
| Taxes Other Than Income Taxes | 2 |
| Carrying Costs Income | 10 |
| Interest Expense | (11) |
| Other Income | 4 |
| Total Change in Operating Expenses and Other | 8 |
| Income Tax Expense | (14) |
| Six Months Ended June 30, 2006 | \$ 83 |

Net Income increased \$12 million to \$83 million in 2006. The key drivers of the increase were an \$18 million net increase in Gross Margin and an \$8 million net decrease in Operating Expenses and Other, offset by a \$14 million

increase in Income Tax Expense.

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

- Retail Margins increased \$33 million in comparison to 2005 primarily due to a \$24 million increase in revenues related to financial transmission rights, net of congestion, a \$17 million increase in retail revenues primarily related to two new industrial customers and a \$12 million reduction in capacity settlement payments under the Interconnection Agreement due to our lower MLR share and our increased capacity. These increases were partially offset by a \$14 million decline in fuel margins caused primarily by higher fuel costs.
- Transmission Revenues decreased \$16 million primarily due to the elimination of SECA revenues as of April 1, 2006 and a \$5 million provision for potential SECA refunds pending settlement negotiations with various intervenors. See the "SECA Revenue Subject to Refund" section of Note 3 - Rate Matters.

Operating Expenses and Other changed between years as follows:

- Carrying Costs Income increased \$10 million primarily due to the establishment of a regulatory asset for carrying costs related to the Virginia environmental and reliability costs incurred.
- Interest Expense increased \$11 million primarily due to long-term debt issuances in 2006, partially offset by an increase in allowance for borrowed funds used during construction.
- Other Income increased \$4 million primarily due to interest income related to an increase in Advances to Affiliates.

Income Taxes

The increase in Income Tax Expense of \$14 million is primarily due to an increase in pretax book income and state income taxes.

Financial Condition

Credit Ratings

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

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

Cash Flow

Cash flows for the six months ended June 30, 2006 and 2005 were as follows:

| | 2006 | 2005 |
|---|-----------------------|-------------|
| | (in thousands) | |
| Cash and Cash Equivalents at Beginning of Period | \$ 1,741 | \$ 1,543 |
| Net Cash Flows From (Used For): | | |
| Operating Activities | 320,554 | 87,588 |

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| | | |
|---|-----------------|-----------------|
| Investing Activities | (622,504) | (269,487) |
| Financing Activities | 301,555 | 181,637 |
| Net Decrease in Cash and Cash Equivalents | (395) | (262) |
| Cash and Cash Equivalents at End of Period | \$ 1,346 | \$ 1,281 |

Operating Activities

Net Cash Flows From Operating Activities were \$321 million in 2006. We produced Net Income of \$83 million during the period and a noncash expense item of \$96 million for Depreciation and Amortization. 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 working capital included two significant items. We had a decrease of \$60 million in Accounts Receivable, Net due to the collection of receivables related to power sales to affiliates, settled litigation and sales on emission allowances. We had an increase of \$42 million in Accrued Taxes, Net related to the lack of federal income tax payments made in 2006.

Net Cash Flows From Operating Activities were \$88 million in 2005. We produced income of \$71 million during the period and a noncash expense item of \$96 million for Depreciation and Amortization partially offset by Pension Contributions to Qualified Plan Trusts of \$40 million. 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 working capital had no significant items.

Investing Activities

Net Cash Flows Used For Investing Activities during 2006 and 2005 primarily reflect our construction expenditures of \$404 million and \$277 million, respectively. Construction expenditures are primarily for projects to improve service reliability for transmission and distribution, as well as environmental upgrades for both periods. In 2006 and 2005, capital projects for transmission expenditures primarily relate to the Wyoming-Jacksons Ferry 765 kV line placed in service in June 2006. Environmental upgrades include the flue gas desulphurization (FGD) projects at the Amos and Mountaineer Plants. For the remainder of 2006, we expect \$530 million of construction expenditures. In addition, we invested \$219 million into the Utility Money Pool, in 2006.

Financing Activities

Net Cash Flows From Financing Activities were \$302 million in 2006. We issued \$500 million in senior notes and issued \$50 million in pollution control bonds. We also retired a First Mortgage Bond of \$100 million. We repaid short-term borrowings from the Utility Money Pool of \$194 million. In addition, we received funds of \$68 million related to a long-term coal purchase contract amended in March 2006. See "Coal Contract Amendment" within "Significant Factors" for additional information.

Net Cash Flows From Financing Activities were \$182 million in 2005. We issued three Senior Unsecured Notes totaling \$600 million. We also issued Notes Payable - Affiliates of \$100 million and received a capital contribution from our parent of \$100 million. We retired \$450 million of Senior Unsecured Notes and three First Mortgage Bonds totaling \$125 million. In addition, we repaid \$34 million of advances from the Utility Money Pool.

Financing Activity

Long-term debt issuances and retirements during the first six months of 2006 were:

Issuances

| Type of Debt | Principal Amount (in thousands) | Interest Rate (%) | Due Date |
|-------------------------|---|-----------------------------|-----------------|
| Pollution Control Bonds | \$ 50,275 | Variable | 2036 |
| Senior Unsecured Notes | 250,000 | 5.55 | 2011 |
| Senior Unsecured Notes | 250,000 | 6.375 | 2036 |

Retirements

| Type of Debt | Principal Amount (in thousands) | Interest Rate (%) | Due Date |
|----------------------|---|-----------------------------|-----------------|
| First Mortgage Bonds | \$ 100,000 | 6.80 | 2006 |
| Other Debt | 5 | 13.718 | 2026 |

Liquidity

We have solid investment grade ratings, which provide us ready access to capital markets in order to issue new debt or refinance long-term debt maturities. In addition, we participate in the Utility Money Pool, which provides access to AEP's liquidity.

Summary Obligation Information

A summary of our contractual obligations is included in our 2005 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed above.

Significant Factors***Coal Contract Amendment***

We negotiated an amendment to a nonderivative coal contract that was assigned to a new owner of a coal supplier to which we were contractually obligated. The amended contract includes adjustments in the quantity related to the shortfall of tons in prior years, escalated tonnage deliveries in 2006 and a pricing change related to future coal deliveries. In March 2006, the new owner agreed to pay us \$80 million for the settlement, release and amendment of the original contract. With respect to prior years' undelivered coal, the new owner paid us \$12 million for the shortfall tons. With respect to deliveries of coal in 2006-2007, the third party paid us the remaining \$68 million for the agreed upon price increase.

The receipt of funds reduces the risk that the third party will short future deliveries. However, if they fail to deliver, we are not contractually obligated to repay any portion of the settlement payment. Our net coal price will not materially change from the original contract price as a result of the \$68 million payment that we received for future coal deliveries through 2007.

Since there are no further requirements related to the liquidation of the shortfall tons, we recognized the \$12 million shortfall payment in the first quarter of 2006. We recorded a \$5 million reduction in Regulatory Assets on our Condensed Consolidated Balance Sheet and recorded the remaining \$7 million as a reduction to Fuel and Other Consumables for Electric Generation on our Condensed Consolidated Statement of Income. We recorded the \$68 million payment within Deferred Credits and Other on our Condensed Consolidated Balance Sheet. To the extent tons are received, payment of the higher contracted price per ton will effectively result in a repayment of funds to the coal supplier.

Litigation and Regulatory Activity

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our pending litigation and regulatory proceedings, see Note 4 - Rate Matters, Note 6 - Customer Choice and Industry Restructuring and Note 7 - Commitments and Contingencies in our 2005 Annual Report. Also, see Note 3 - Rate Matters and Note 5 - Commitments and Contingencies in the "Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries" section. An adverse result in these proceedings has the potential to materially affect our results of operations, financial condition and cash flows.

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

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2005 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES**Market Risks**

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

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our condensed consolidated balance sheet as of June 30, 2006 and the reasons for changes in our total MTM value as compared to December 31, 2005.

**Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheet
As of June 30, 2006
(in thousands)**

| | MTM Risk Management Contracts | Cash Flow & Fair Value Hedges | DETM Assignment (a) | Total |
|---|--|--|------------------------------------|------------------|
| Current Assets | \$ 71,996 | \$ 18,587 | \$ - | \$ 90,583 |
| Noncurrent Assets | 126,964 | 989 | - | 127,953 |
| Total MTM Derivative Contract Assets | 198,960 | 19,576 | - | 218,536 |
| Current Liabilities | (54,973) | (4,849) | (1,610) | (61,432) |
| Noncurrent Liabilities | (88,104) | (936) | (10,331) | (99,371) |
| Total MTM Derivative Contract Liabilities | (143,077) | (5,785) | (11,941) | (160,803) |
| Total MTM Derivative Contract Net Assets (Liabilities) | \$ 55,883 | \$ 13,791 | \$ (11,941) | \$ 57,733 |

(a) See "Natural Gas Contracts with DETM" section of Note 17 of the 2005 Annual Report.

**MTM Risk Management Contract Net Assets
Six Months Ended June 30, 2006
(in thousands)**

| | |
|---|------------------|
| Total MTM Risk Management Contract Net Assets at December 31, 2005 | \$ 56,407 |
| (Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period | (4,766) |
| Fair Value of New Contracts at Inception When Entered During the Period (a) | 137 |
| Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period | (1,234) |
| Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts | 359 |
| Changes in Fair Value Due to Market Fluctuations During the Period (b) | 4,968 |
| Changes due to SIA Agreement (c) | (6,533) |
| Changes in Fair Value Allocated to Regulated Jurisdictions (d) | 6,545 |

| | |
|---|------------------|
| Total MTM Risk Management Contract Net Assets | 55,883 |
| Net Cash Flow & Fair Value Hedge Contracts | 13,791 |
| DETM Assignment (e) | (11,941) |
| Total MTM Risk Management Contract Net Assets at June 30, 2006 | \$ 57,733 |

- (a) 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.
- (b) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
- (c) See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 3.
- (d) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
- (e) See "Natural Gas Contracts with DETM" section of Note 17 of the 2005 Annual Report.

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

The following table presents:

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

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets Fair Value of Contracts as of June 30, 2006 (in thousands)

| | Remainder 2006 | 2007 | 2008 | 2009 | 2010 | After 2010 | Total |
|---|---------------------------|------------------|------------------|------------------|-----------------|-----------------------|------------------|
| Prices Actively Quoted - Exchange Traded Contracts | \$ (3,470) | \$ 3,878 | \$ 3,971 | \$ - | \$ - | \$ - | 4,379 |
| Prices Provided by Other External Sources - OTC | | | | | | | |
| Broker Quotes (a) | 11,195 | 10,112 | 3,861 | 7,480 | - | - | 32,648 |
| Prices Based on Models and Other Valuation Methods (b) | 276 | 450 | 2,585 | 4,118 | 8,704 | 2,723 | 18,856 |
| Total | \$ 8,001 | \$ 14,440 | \$ 10,417 | \$ 11,598 | \$ 8,704 | \$ 2,723 | \$ 55,883 |

- (a) "Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
- (b) "Prices Based on Models and Other Valuation Methods" is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying

commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

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

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

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

We employ forward contracts as cash flow hedges to lock-in prices on certain transactions which have been denominated in foreign currencies where deemed necessary. We do not hedge all foreign currency exposure.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Condensed Consolidated Balance Sheets and the reasons for the changes from December 31, 2005 to June 30, 2006. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity Six Months Ended June 30, 2006 (in thousands)

| | Power | Foreign Currency | Interest Rate | Total |
|--|------------|---------------------|------------------|-------------|
| Beginning Balance in AOCI December 31, 2005 | \$ (1,480) | \$ (171) | \$ (14,770) | \$ (16,421) |
| Changes in Fair Value | 10,987 | - | 4,951 | 15,938 |
| Impact due to Changes in SIA (a) | (442) | - | - | (442) |
| Reclassifications from AOCI to Net Income for Cash Flow | | | | |
| Hedges Settled | 1,089 | 3 | 1,410 | 2,502 |
| Ending Balance in AOCI June 30, 2006 | \$ 10,154 | \$ (168) | \$ (8,409) | \$ 1,577 |

(a) See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 3.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a \$7,941 thousand gain.

Credit Risk

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

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate

volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at June 30, 2006, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

| Six Months Ended June 30, 2006 (in thousands) | | | | Twelve Months Ended December 31, 2005 (in thousands) | | | |
|--|-------------|----------------|------------|---|-------------|----------------|------------|
| End | High | Average | Low | End | High | Average | Low |
| \$685 | \$1,604 | \$695 | \$401 | \$732 | \$1,216 | \$579 | \$209 |

VaR Associated with Debt Outstanding

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was \$178 million and \$142 million at June 30, 2006 and December 31, 2005, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

| | Three Months Ended | | Six Months Ended | |
|---|--------------------|------------------|------------------|------------------|
| | 2006 | 2005 | 2006 | 2005 |
| REVENUES | | | | |
| Electric Generation, Transmission and Distribution | \$ 464,058 | \$ 436,343 | \$ 1,024,051 | \$ 912,370 |
| Sales to AEP Affiliates | 48,608 | 58,927 | 120,380 | 138,097 |
| Other | 1,922 | 1,832 | 4,598 | 4,330 |
| TOTAL | 514,588 | 497,102 | 1,149,029 | 1,054,797 |
| EXPENSES | | | | |
| Fuel and Other Consumables for Electric Generation | 155,240 | 125,759 | 322,093 | 240,903 |
| Purchased Electricity for Resale | 29,979 | 26,732 | 57,595 | 54,965 |
| Purchased Electricity from AEP Affiliates | 103,457 | 107,023 | 225,856 | 233,986 |
| Other Operation | 77,458 | 76,722 | 147,655 | 150,495 |
| Maintenance | 46,668 | 37,266 | 84,507 | 84,456 |
| Depreciation and Amortization | 48,386 | 46,491 | 96,358 | 96,450 |
| Taxes Other Than Income Taxes | 22,799 | 23,357 | 45,891 | 47,431 |
| TOTAL | 483,987 | 443,350 | 979,955 | 908,686 |
| OPERATING INCOME | 30,601 | 53,752 | 169,074 | 146,111 |
| Other Income (Expense): | | | | |
| Interest Income | 2,814 | 443 | 3,765 | 1,005 |
| Carrying Costs Income | 7,773 | 3,967 | 13,784 | 4,065 |
| Allowance for Equity Funds Used During Construction | 4,083 | 2,557 | 6,559 | 4,768 |
| Interest Expense | (31,653) | (27,145) | (61,921) | (51,344) |
| INCOME BEFORE INCOME TAXES | 13,618 | 33,574 | 131,261 | 104,605 |
| Income Tax Expense | 3,971 | 9,361 | 48,020 | 33,720 |
| NET INCOME | 9,647 | 24,213 | 83,241 | 70,885 |
| Preferred Stock Dividend Requirements Including Capital Stock Expense and Other | 238 | 905 | 476 | 1,702 |
| EARNINGS APPLICABLE TO COMMON STOCK | \$ 9,409 | \$ 23,308 | \$ 82,765 | \$ 69,183 |

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

| | Common Stock | Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total |
|--|-----------------|--------------------|----------------------|---|--------------|
| DECEMBER 31, 2004 | \$ 260,458 | \$ 722,314 | \$ 508,618 | \$ (81,672) | \$ 1,409,718 |
| Capital Contribution From Parent | | 100,000 | | | 100,000 |
| Preferred Stock Dividends | | | (400) | | (400) |
| Capital Stock Expense and Other | | 2,447 | (1,302) | | 1,145 |
| TOTAL | | | | | 1,510,463 |
| COMPREHENSIVE INCOME | | | | | |
| Other Comprehensive Loss, Net of Taxes: | | | | | |
| Cash Flow Hedges, Net of Tax of \$7,474 | | | | (13,882) | (13,882) |
| NET INCOME | | | 70,885 | | 70,885 |
| TOTAL COMPREHENSIVE INCOME | | | | | 57,003 |
| JUNE 30, 2005 | \$ 260,458 | \$ 824,761 | \$ 577,801 | \$ (95,554) | \$ 1,567,466 |
| DECEMBER 31, 2005 | \$ 260,458 | \$ 924,837 | \$ 635,016 | \$ (16,610) | \$ 1,803,701 |
| Common Stock Dividends | | | (5,000) | | (5,000) |
| Preferred Stock Dividends | | | (400) | | (400) |
| Capital Stock Expense and Other | | 80 | (76) | | 4 |
| TOTAL | | | | | 1,798,305 |
| COMPREHENSIVE INCOME | | | | | |
| Other Comprehensive Income, Net of Taxes: | | | | | |
| Cash Flow Hedges, Net of Tax of \$9,692 | | | | 17,998 | 17,998 |
| NET INCOME | | | 83,241 | | 83,241 |
| TOTAL COMPREHENSIVE INCOME | | | | | 101,239 |
| JUNE 30, 2006 | \$ 260,458 | \$ 924,917 | \$ 712,781 | \$ 1,388 | \$ 1,899,544 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS

ASSETS

June 30, 2006 and December 31, 2005

(in thousands)

(Unaudited)

| | 2006 | 2005 |
|---|---------------------|---------------------|
| CURRENT ASSETS | | |
| Cash and Cash Equivalents | \$ 1,346 | \$ 1,741 |
| Advances to Affiliates | 218,702 | - |
| Accounts Receivable: | | |
| Customers | 168,893 | 141,810 |
| Affiliated Companies | 86,461 | 153,453 |
| Accrued Unbilled Revenues | 30,571 | 51,201 |
| Miscellaneous | 3,658 | 527 |
| Allowance for Uncollectible Accounts | (4,742) | (1,805) |
| Total Accounts Receivable | 284,841 | 345,186 |
| Fuel | 72,947 | 64,657 |
| Materials and Supplies | 55,288 | 54,967 |
| Risk Management Assets | 90,583 | 132,247 |
| Accrued Tax Benefits | - | 32,979 |
| Prepayments and Other | 37,559 | 75,129 |
| TOTAL | 761,266 | 706,906 |
| PROPERTY, PLANT AND EQUIPMENT | | |
| Electric: | | |
| Production | 2,826,293 | 2,798,157 |
| Transmission | 1,585,714 | 1,266,855 |
| Distribution | 2,202,696 | 2,141,153 |
| Other | 337,359 | 323,158 |
| Construction Work in Progress | 593,062 | 647,638 |
| Total | 7,545,124 | 7,176,961 |
| Accumulated Depreciation and Amortization | 2,556,021 | 2,524,855 |
| TOTAL - NET | 4,989,103 | 4,652,106 |
| OTHER NONCURRENT ASSETS | | |
| Regulatory Assets | 452,651 | 457,294 |
| Long-term Risk Management Assets | 127,953 | 176,231 |
| Deferred Charges and Other | 252,291 | 261,556 |
| TOTAL | 832,895 | 895,081 |
| TOTAL ASSETS | \$ 6,583,264 | \$ 6,254,093 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
June 30, 2006 and December 31, 2005
(Unaudited)

| | 2006 | 2005 |
|--|---------------------|---------------------|
| | (in thousands) | |
| CURRENT LIABILITIES | | |
| Advances from Affiliates | \$ - | \$ 194,133 |
| Accounts Payable: | | |
| General | 276,383 | 230,570 |
| Affiliated Companies | 78,307 | 85,941 |
| Long-term Debt Due Within One Year - Nonaffiliated | 171,645 | 146,999 |
| Risk Management Liabilities | 61,432 | 121,165 |
| Customer Deposits | 55,030 | 79,854 |
| Accrued Taxes | 59,211 | 49,833 |
| Other | 113,883 | 108,746 |
| TOTAL | 815,891 | 1,017,241 |
| NONCURRENT LIABILITIES | | |
| Long-term Debt - Nonaffiliated | 2,325,465 | 1,904,379 |
| Long-term Debt - Affiliated | 100,000 | 100,000 |
| Long-term Risk Management Liabilities | 99,371 | 147,117 |
| Deferred Income Taxes | 943,008 | 952,497 |
| Regulatory Liabilities and Deferred Investment Tax Credits | 208,725 | 201,230 |
| Deferred Credits and Other | 173,494 | 110,144 |
| TOTAL | 3,850,063 | 3,415,367 |
| TOTAL LIABILITIES | 4,665,954 | 4,432,608 |
| Cumulative Preferred Stock Not Subject to Mandatory Redemption | 17,766 | 17,784 |
| Commitments and Contingencies (Note 5) | | |
| COMMON SHAREHOLDER'S EQUITY | | |
| Common Stock - No Par Value: | | |
| Authorized - 30,000,000 Shares | | |
| Outstanding - 13,499,500 Shares | 260,458 | 260,458 |
| Paid-in Capital | 924,917 | 924,837 |
| Retained Earnings | 712,781 | 635,016 |
| Accumulated Other Comprehensive Income (Loss) | 1,388 | (16,610) |
| TOTAL | 1,899,544 | 1,803,701 |
| TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY | \$ 6,583,264 | \$ 6,254,093 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

| | 2006 | 2005 |
|---|------------------|------------------|
| OPERATING ACTIVITIES | | |
| Net Income | \$ 83,241 | \$ 70,885 |
| Adjustments for Noncash Items: | | |
| Depreciation and Amortization | 96,358 | 96,450 |
| Deferred Income Taxes | (1,466) | 18,206 |
| Carrying Costs Income | (13,784) | (4,065) |
| Mark-to-Market of Risk Management Contracts | 147 | (13,473) |
| Pension Contributions to Qualified Plan Trusts | - | (39,875) |
| Over/Under Fuel Recovery, Net | 3,636 | (8,759) |
| Change in Other Noncurrent Assets | 9,872 | (11,224) |
| Change in Other Noncurrent Liabilities | 17,986 | (20,276) |
| Changes in Components of Working Capital: | | |
| Accounts Receivable, Net | 60,345 | 16,710 |
| Fuel, Materials and Supplies | (8,611) | (25,875) |
| Margin Deposits | 27,872 | (4,899) |
| Accounts Payable | 14,993 | 36,157 |
| Customer Deposits | (24,824) | 15,447 |
| Accrued Taxes, Net | 42,357 | (29,847) |
| Other Current Assets | 7,295 | (4,394) |
| Other Current Liabilities | 5,137 | (3,580) |
| Net Cash Flows From Operating Activities | 320,554 | 87,588 |
| INVESTING ACTIVITIES | | |
| Construction Expenditures | (404,252) | (277,177) |
| Change in Other Cash Deposits, Net | - | (41) |
| Change in Advances to Affiliates, Net | (218,702) | - |
| Proceeds from Sales of Assets | 450 | 7,731 |
| Net Cash Flows Used For Investing Activities | (622,504) | (269,487) |
| FINANCING ACTIVITIES | | |
| Capital Contributions from Parent | - | 100,000 |
| Issuance of Long-term Debt - Nonaffiliated | 544,364 | 594,717 |
| Issuance of Long-term Debt - Affiliated | - | 100,000 |
| Change in Advances from Affiliates, Net | (194,133) | (34,368) |
| Retirement of Long-term Debt - Nonaffiliated | (100,005) | (575,005) |
| Retirement of Preferred Stock | (14) | - |
| Principal Payments for Capital Lease Obligations | (2,768) | (3,307) |
| Funds From Amended Coal Contract, Net | 59,511 | - |
| Dividends Paid on Common Stock | (5,000) | - |
| Dividends Paid on Cumulative Preferred Stock | (400) | (400) |
| Net Cash Flows From Financing Activities | 301,555 | 181,637 |
| Net Decrease in Cash and Cash Equivalents | (395) | (262) |

| | | | | |
|---|----|-------|----|-------|
| Cash and Cash Equivalents at Beginning of Period | | 1,741 | | 1,543 |
| Cash and Cash Equivalents at End of Period | \$ | 1,346 | \$ | 1,281 |

SUPPLEMENTAL DISCLOSURE

| | | | | |
|--|----|---------|----|--------|
| Cash Paid for Interest, Net of Capitalized Amounts | \$ | 51,558 | \$ | 45,064 |
| Cash Paid for Income Taxes, Net of Refunds | | 4,562 | | 47,461 |
| Noncash Acquisitions Under Capital Leases | | 2,287 | | 748 |
| Construction Expenditures Included in Accounts Payable at June 30, | | 105,826 | | 36,339 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
INDEX TO CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT
SUBSIDIARIES

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

| | Footnote Reference |
|---|-------------------------------|
| Significant Accounting Matters | Note 1 |
| New Accounting Pronouncements | Note 2 |
| Rate Matters | Note 3 |
| Commitments and Contingencies | Note 5 |
| Guarantees | Note 6 |
| Company-wide Staffing and Budget Review | Note 7 |
| Benefit Plans | Note 9 |
| Business Segments | Note 11 |
| Financing Activities | Note 12 |

**COLUMBUS SOUTHERN POWER COMPANY
AND SUBSIDIARIES**

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

Second Quarter of 2006 Compared to Second Quarter of 2005

**Reconciliation of Second Quarter of 2005 to Second Quarter of 2006 Net Income
(in millions)**

| | | |
|---|------|-------------|
| Second Quarter of 2005 | \$ | 35 |
| Changes in Gross Margin: | | |
| Retail Margins | 32 | |
| Off-system Sales | 2 | |
| Transmission Revenues | (9) | |
| Other | 2 | |
| Total Change in Gross Margin | | 27 |
| Changes in Operating Expenses and Other: | | |
| Other Operation and Maintenance | (1) | |
| Depreciation and Amortization | (19) | |
| Taxes Other Than Income Taxes | (9) | |
| Carrying Costs Income | (3) | |
| Interest Expense | (2) | |
| Total Change in Operating Expenses and Other | | (34) |
| Income Tax Expense | | 4 |
| Second Quarter of 2006 | \$ | 32 |

Net Income remained relatively flat in the second quarter of 2006 compared to the second quarter of 2005.

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

- Retail Margins were \$32 million higher than the prior period primarily due to Rate Stabilization Plan (RSP) and Transition Regulatory Asset rate increases effective January 1, 2006 as well as the addition of Monongahela Power's Ohio customers on December 31, 2005, partially offset by an increase in delivered fuel costs.
- Transmission Revenues decreased \$9 million primarily due to the elimination of SECA revenues as of April 1, 2006 and a \$3 million provision for potential SECA refunds pending settlement negotiations with various intervenors. See the "SECA Revenue Subject to Refund" section of Note 3 - Rate Matters.

Operating Expenses and Other changed between years as follows:

Depreciation and Amortization expense increased \$19 million due to the 2005 RSP order that resulted in the reversal of unused shopping credits of \$18 million partially offset by the establishment of a \$7 million regulatory liability to benefit low-income customers and for economic development. Depreciation expense also increased due to a greater depreciable base resulting primarily from the acquisitions of the Waterford Plant and Monongahela Power's Ohio assets in the second half of 2005.

- Taxes Other Than Income Taxes increased \$9 million due to an increase in real and personal property taxes.

Income Tax

The decrease of \$4 million in Income Tax Expense is primarily due to a decrease in pretax book income and state income taxes.

Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2005

Reconciliation of Six Months Ended June 30, 2005 to Six Months Ended June 30, 2006 Net Income (in millions)

| | | |
|---|------|------|
| Six Months Ended June 30, 2005 | \$ | 82 |
| Changes in Gross Margin: | | |
| Retail Margins | 56 | |
| Off-system Sales | 9 | |
| Transmission Revenues | (7) | |
| Other | 9 | |
| Total Change in Gross Margin | | 67 |
| Changes in Operating Expenses and Other: | | |
| Other Operation and Maintenance | (16) | |
| Depreciation and Amortization | (27) | |
| Taxes Other Than Income Taxes | (12) | |
| Carrying Costs Income | (5) | |
| Interest Expense | (6) | |
| Total Change in Operating Expenses and Other | | (66) |
| Income Tax Expense | | 1 |
| Six Months Ended June 30, 2006 | \$ | 84 |

Net Income remained relatively flat for the six months ended June 30, 2006 compared to the six months ended June 30, 2005.

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

- Retail Margins increased \$56 million primarily due to the RSP and Transition Regulatory Asset rate increases effective January 1, 2006 as well as the addition of Monongahela Power Ohio customers on December 31, 2005, partially offset by an increase in delivered fuel costs.
- Off-system Sales increased \$9 million due to higher physical sales partially offset by lower optimization activity.

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- Transmission Revenues decreased \$7 million primarily due to the elimination of SECA revenues as of April 1, 2006 and a \$3 million provision for potential SECA refunds pending settlement negotiations with various intervenors. See the “SECA Revenue Subject to Refund” section of Note 3 - Rate Matters.
- Other revenues increased \$9 million primarily due to higher gains on sales of emission allowances.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance increased \$16 million due to the 2005 establishment of a regulatory asset for PJM administrative fees, an increase in transmission expenses related to the AEP Transmission Equalization Agreement and favorable adjustments in the prior year related to the corporate-owned life insurance policy.
- Depreciation and Amortization expense increased \$27 million primarily due to the 2005 RSP order that resulted in the reversal of unused shopping credits of \$18 million partially offset by the establishment of a \$7 million regulatory liability to benefit low-income customers and for economic development. Depreciation expense also increased due to a greater depreciable base resulting primarily from the acquisitions of the Waterford Plant and Monongahela Power’s Ohio assets in the second half of 2005.
- Taxes Other Than Income Taxes increased \$12 million due to increases in real and personal property taxes.
- Carrying Costs Income decreased \$5 million primarily due to the completion of deferrals of the environmental carrying costs from 2004 and 2005 that are now recovered during 2006 through 2008 according to RSP.
- Interest Expense increased \$6 million primarily due to a new long-term debt issuance during the fourth quarter of 2005.

Income Tax

The decrease of \$1 million in Income Tax Expense is primarily due to a decrease in state income taxes.

Financial Condition

Credit Ratings

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

| | Moody’s | S&P | Fitch |
|-----------------------|----------------|----------------|--------------|
| Senior Unsecured Debt | A3 | BBB | A- |

Financing Activity

There were no long-term debt issuances or retirements during the first six months of 2006.

Liquidity

We have solid investment grade ratings, which provide us ready access to capital markets in order to issue new debt or refinance long-term debt maturities. In addition, we participate in the Utility Money Pool, which provides access to AEP’s liquidity.

Summary Obligation Information

A summary of our contractual obligations is included in our 2005 Annual Report and has not changed significantly from year-end.

Significant Factors

Litigation and Regulatory Activity

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our pending litigation and regulatory proceedings, see Note 4 - Rate Matters, Note 6 - Customer Choice and Industry Restructuring and Note 7 - Commitments and Contingencies in our 2005 Annual Report. Also, see Note 3 - Rate Matters, Note 4 - Customer Choice and Industry Restructuring and Note 5 - Commitments and Contingencies in the "Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries" section. An adverse result in these proceedings has the potential to materially affect our results of operations, financial condition and cash flows.

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

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2005 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES**Market Risks**

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

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our condensed consolidated balance sheet as of June 30, 2006 and the reasons for changes in our total MTM value as compared to December 31, 2005.

**Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheet
As of June 30, 2006
(in thousands)**

| | MTM Risk Management Contracts | Cash Flow Hedges | DETM Assignment (a) | Total |
|---|--|-----------------------------|------------------------------------|------------------|
| Current Assets | \$ 42,197 | \$ 10,989 | \$ - | \$ 53,186 |
| Noncurrent Assets | 74,861 | 585 | - | 75,446 |
| Total MTM Derivative Contract Assets | 117,058 | 11,574 | - | 128,632 |
| Current Liabilities | (31,803) | (2,354) | (952) | (35,109) |
| Noncurrent Liabilities | (51,549) | - | (6,108) | (57,657) |
| Total MTM Derivative Contract Liabilities | (83,352) | (2,354) | (7,060) | (92,766) |
| Total MTM Derivative Contract Net Assets (Liabilities) | \$ 33,706 | \$ 9,220 | \$ (7,060) | \$ 35,866 |

(a) See "Natural Gas Contracts with DETM" section of Note 17 of the 2005 Annual Report.

**MTM Risk Management Contract Net Assets
Six Months Ended June 30, 2006
(in thousands)**

| | |
|---|------------------|
| Total MTM Risk Management Contract Net Assets at December 31, 2005 | \$ 33,322 |
| (Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period | (4,894) |
| Fair Value of New Contracts at Inception When Entered During the Period (a) | 139 |
| Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period | (673) |
| Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts | 364 |
| Changes in Fair Value Due to Market Fluctuations During the Period (b) | 9,198 |
| Changes Due to SIA (c) | (3,864) |
| Changes in Fair Value Allocated to Regulated Jurisdictions (d) | 114 |
| Total MTM Risk Management Contract Net Assets | 33,706 |

| | |
|---|------------------|
| Net Cash Flow Hedge Contracts | 9,220 |
| DETM Assignment (e) | (7,060) |
| Total MTM Risk Management Contract Net Assets at June 30, 2006 | \$ 35,866 |

- (a) 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.
- (b) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
- (c) See “Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement” section of Note 3.
- (d) “Changes in Fair Value Allocated to Regulated Jurisdictions” relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
- (e) See “Natural Gas Contracts with DETM” section of Note 17 of the 2005 Annual Report.

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

The following table presents:

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

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets Fair Value of Contracts as of June 30, 2006 (in thousands)

| | Remainder 2006 | 2007 | 2008 | 2009 | 2010 | After 2010 | Total |
|--|-------------------|-----------------|-----------------|-----------------|-----------------|-----------------|------------------|
| Prices Actively Quoted - Exchange Traded Contracts | \$ (2,051) | \$ 2,293 | \$ 2,348 | \$ - | \$ - | \$ - | \$ 2,590 |
| Prices Provided by Other External Sources - OTC Broker | | | | | | | |
| Quotes (a) | 6,669 | 6,064 | 2,261 | 4,422 | - | - | 19,416 |
| Prices Based on Models and Other Valuation Methods (b) | 178 | 618 | 1,714 | 2,434 | 5,146 | 1,610 | 11,700 |
| Total | \$ 4,796 | \$ 8,975 | \$ 6,323 | \$ 6,856 | \$ 5,146 | \$ 1,610 | \$ 33,706 |

- (a) “Prices Provided by Other External Sources - OTC Broker Quotes” reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
- (b) “Prices Based on Models and Other Valuation Methods” is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition,

where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

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

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

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Condensed Consolidated Balance Sheets and the reasons for the changes from December 31, 2005 to June 30, 2006. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity Six Months Ended June 30, 2006 (in thousands)

| | Power |
|---|-----------------|
| Beginning Balance in AOCI December 31, 2005 | \$ (859) |
| Changes in Fair Value | 6,479 |
| Impact due to Changes in SIA (a) | (261) |
| Reclassifications from AOCI to Net Income for Cash Flow | |
| Hedges Settled | 643 |
| Ending Balance in AOCI June 30, 2006 | \$ 6,002 |

(a) See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 3.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a \$5,624 thousand gain.

Credit Risk

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

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at June 30, 2006, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

| Six Months Ended June 30, 2006 (in thousands) | | | | Twelve Months Ended December 31, 2005 (in thousands) | | | |
|--|-------------|----------------|------------|---|-------------|----------------|------------|
| End | High | Average | Low | End | High | Average | Low |
| \$405 | \$948 | \$411 | \$237 | \$424 | \$705 | \$335 | \$121 |

VaR Associated with Debt Outstanding

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was \$84 million and \$86 million at June 30, 2006 and December 31, 2005, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

| | Three Months Ended | | Six Months Ended | |
|---|--------------------|------------------|------------------|------------------|
| | 2006 | 2005 | 2006 | 2005 |
| REVENUES | | | | |
| Electric Generation, Transmission and Distribution | \$ 395,347 | \$ 337,563 | \$ 810,346 | \$ 669,882 |
| Sales to AEP Affiliates | 21,762 | 22,427 | 35,531 | 57,241 |
| TOTAL | 417,109 | 359,990 | 845,877 | 727,123 |
| EXPENSES | | | | |
| Fuel and Other Consumables for Electric Generation | 71,213 | 52,203 | 141,033 | 118,638 |
| Purchased Electricity for Resale | 27,688 | 8,703 | 52,453 | 17,906 |
| Purchased Electricity from AEP Affiliates | 87,188 | 95,172 | 169,665 | 174,947 |
| Other Operation | 57,866 | 53,328 | 113,827 | 96,557 |
| Maintenance | 23,502 | 26,700 | 41,436 | 42,084 |
| Depreciation and Amortization | 46,534 | 27,333 | 92,346 | 65,531 |
| Taxes Other Than Income Taxes | 41,787 | 32,993 | 81,289 | 69,235 |
| TOTAL | 355,778 | 296,432 | 692,049 | 584,898 |
| OPERATING INCOME | 61,331 | 63,558 | 153,828 | 142,225 |
| Other Income (Expense): | | | | |
| Interest Income | 475 | 711 | 930 | 1,628 |
| Carrying Costs Income | 1,320 | 4,159 | 2,036 | 6,916 |
| Allowance for Equity Funds Used During Construction | 343 | 528 | 807 | 807 |
| Interest Expense | (16,914) | (15,669) | (34,434) | (28,581) |
| INCOME BEFORE INCOME TAXES | 46,555 | 53,287 | 123,167 | 122,995 |
| Income Tax Expense | 14,293 | 18,636 | 39,568 | 40,876 |
| NET INCOME | 32,262 | 34,651 | 83,599 | 82,119 |
| Capital Stock Expense | 40 | 1,858 | 79 | 2,112 |
| EARNINGS APPLICABLE TO COMMON STOCK | \$ 32,222 | \$ 32,793 | \$ 83,520 | \$ 80,007 |

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

| | Common Stock | Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total |
|--|-----------------|--------------------|----------------------|--|----------------|
| DECEMBER 31, 2004 | \$ 41,026 | \$ 577,415 | \$ 341,025 | \$ (60,816) | \$ 898,650 |
| Common Stock Dividends | | | (57,000) | | (57,000) |
| Capital Stock Expense | | 2,112 | (2,112) | | - |
| TOTAL | | | | | 841,650 |
| COMPREHENSIVE INCOME | | | | | |
| Other Comprehensive Loss, Net of Taxes: | | | | | |
| Cash Flow Hedges, Net of Tax of \$2,307 | | | | (4,285) | (4,285) |
| NET INCOME | | | 82,119 | | 82,119 |
| TOTAL COMPREHENSIVE INCOME | | | | | 77,834 |
| JUNE 30, 2005 | \$ 41,026 | \$ 579,527 | \$ 364,032 | \$ (65,101) | \$ 919,484 |
| DECEMBER 31, 2005 | \$ 41,026 | \$ 580,035 | \$ 361,365 | \$ (880) | \$ 981,546 |
| Common Stock Dividends | | | (45,000) | | (45,000) |
| Capital Stock Expense | | 79 | (79) | | - |
| TOTAL | | | | | 936,546 |
| COMPREHENSIVE INCOME | | | | | |
| Other Comprehensive Income, Net of Taxes: | | | | | |
| Cash Flow Hedges, Net of Tax of \$3,695 | | | | 6,861 | 6,861 |
| NET INCOME | | | 83,599 | | 83,599 |
| TOTAL COMPREHENSIVE INCOME | | | | | 90,460 |
| JUNE 30, 2006 | \$ 41,026 | \$ 580,114 | \$ 399,885 | \$ 5,981 | \$ 1,027,006 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS

ASSETS

June 30, 2006 and December 31, 2005

(in thousands)

(Unaudited)

| | 2006 | 2005 |
|---|---------------------|---------------------|
| CURRENT ASSETS | | |
| Cash and Cash Equivalents | \$ 810 | \$ 940 |
| Advances to Affiliates | 12,616 | - |
| Accounts Receivable: | | |
| Customers | 52,106 | 43,143 |
| Affiliated Companies | 30,840 | 67,694 |
| Accrued Unbilled Revenues | 8,361 | 10,086 |
| Miscellaneous | 2,592 | 2,012 |
| Allowance for Uncollectible Accounts | (1,320) | (1,082) |
| Total Accounts Receivable | 92,579 | 121,853 |
| Fuel | 40,277 | 28,579 |
| Materials and Supplies | 30,485 | 27,519 |
| Emission Allowances | 11,283 | 20,181 |
| Risk Management Assets | 53,186 | 76,507 |
| Accrued Tax Benefits | 4,360 | 36,838 |
| Margin Deposits | 584 | 16,832 |
| Prepayments and Other | 8,529 | 6,714 |
| TOTAL | 254,709 | 335,963 |
| PROPERTY, PLANT AND EQUIPMENT | | |
| Electric: | | |
| Production | 1,883,890 | 1,874,652 |
| Transmission | 470,586 | 457,937 |
| Distribution | 1,441,468 | 1,380,722 |
| Other | 186,456 | 184,096 |
| Construction Work in Progress | 179,675 | 129,246 |
| Total | 4,162,075 | 4,026,653 |
| Accumulated Depreciation and Amortization | 1,564,597 | 1,500,858 |
| TOTAL - NET | 2,597,478 | 2,525,795 |
| OTHER NONCURRENT ASSETS | | |
| Regulatory Assets | 223,554 | 231,599 |
| Long-term Risk Management Assets | 75,446 | 101,512 |
| Deferred Charges and Other | 208,185 | 237,925 |
| TOTAL | 507,185 | 571,036 |
| TOTAL ASSETS | \$ 3,359,372 | \$ 3,432,794 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
June 30, 2006 and December 31, 2005
(Unaudited)

| | 2006 | 2005 |
|--|---------------------|---------------------|
| | (in thousands) | |
| CURRENT LIABILITIES | | |
| Advances from Affiliates | \$ - | \$ 17,609 |
| Accounts Payable: | | |
| General | 85,945 | 59,134 |
| Affiliated Companies | 50,801 | 59,399 |
| Risk Management Liabilities | 35,109 | 69,036 |
| Customer Deposits | 32,170 | 47,013 |
| Accrued Taxes | 103,342 | 157,729 |
| Accrued Interest | 19,395 | 18,908 |
| Other | 29,772 | 31,321 |
| TOTAL | 356,534 | 460,149 |
| NONCURRENT LIABILITIES | | |
| Long-term Debt - Nonaffiliated | 1,097,121 | 1,096,920 |
| Long-term Debt - Affiliated | 100,000 | 100,000 |
| Long-term Risk Management Liabilities | 57,657 | 84,291 |
| Deferred Income Taxes | 501,286 | 498,232 |
| Regulatory Liabilities and Deferred Investment Tax Credits | 173,058 | 165,344 |
| Deferred Credits and Other | 46,710 | 46,312 |
| TOTAL | 1,975,832 | 1,991,099 |
| TOTAL LIABILITIES | 2,332,366 | 2,451,248 |
| Commitments and Contingencies (Note 5) | | |
| COMMON SHAREHOLDER'S EQUITY | | |
| Common Stock - No Par Value Per Share: | | |
| Authorized - 24,000,000 Shares | | |
| Outstanding - 16,410,426 Shares | 41,026 | 41,026 |
| Paid-in Capital | 580,114 | 580,035 |
| Retained Earnings | 399,885 | 361,365 |
| Accumulated Other Comprehensive Income (Loss) | 5,981 | (880) |
| TOTAL | 1,027,006 | 981,546 |
| TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY | \$ 3,359,372 | \$ 3,432,794 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Six Months Ended June 30, 2006 and 2005

(in thousands)

(Unaudited)

| | 2006 | | 2005 | |
|--|-------------|------------------|-------------|-----------------|
| OPERATING ACTIVITIES | | | | |
| Net Income | \$ | 83,599 | \$ | 82,119 |
| Adjustments for Noncash Items: | | | | |
| Depreciation and Amortization | | 92,346 | | 65,531 |
| Deferred Income Taxes | | (250) | | (1,593) |
| Mark-to-Market of Risk Management Contracts | | (466) | | (5,171) |
| Deferred Property Taxes | | 30,201 | | 32,210 |
| Change in Other Noncurrent Assets | | (17,206) | | (55,746) |
| Change in Other Noncurrent Liabilities | | 7,111 | | 4,287 |
| Changes in Components of Working Capital: | | | | |
| Accounts Receivable, Net | | 29,274 | | 21,688 |
| Fuel, Materials and Supplies | | (14,664) | | (2,493) |
| Accounts Payable | | 16,866 | | (1,220) |
| Accrued Taxes, Net | | (21,909) | | (93,089) |
| Customer Deposits | | (14,843) | | 7,618 |
| Other Current Assets | | 24,796 | | 334 |
| Other Current Liabilities | | (1,062) | | 948 |
| Net Cash Flows From Operating Activities | | 213,793 | | 55,423 |
| INVESTING ACTIVITIES | | | | |
| Construction Expenditures | | (137,728) | | (79,013) |
| Change in Advances to Affiliates, Net | | (12,616) | | 79,378 |
| Other | | 600 | | 3,663 |
| Net Cash Flows From (Used For) Investing Activities | | (149,744) | | 4,028 |
| FINANCING ACTIVITIES | | | | |
| Change in Advances from Affiliates, Net | | (17,609) | | - |
| Principal Payments for Capital Lease Obligations | | (1,570) | | (1,815) |
| Dividends Paid on Common Stock | | (45,000) | | (57,000) |
| Net Cash Flows Used For Financing Activities | | (64,179) | | (58,815) |
| Net Increase (Decrease) in Cash and Cash Equivalents | | | | |
| Cash and Cash Equivalents at Beginning of Period | | 940 | | 58 |
| Cash and Cash Equivalents at End of Period | \$ | 810 | \$ | 694 |
| SUPPLEMENTARY INFORMATION | | | | |
| Cash Paid for Interest, Net of Capitalized Amounts | \$ | 32,374 | \$ | 27,390 |
| Cash Paid for Income Taxes, Net of Refunds | | 10,713 | | 78,019 |
| Noncash Acquisitions Under Capital Leases | | 1,648 | | 343 |
| Construction Expenditures Included in Accounts Payable at June 30, | | 12,601 | | 4,426 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
INDEX TO CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT
SUBSIDIARIES

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

| | Footnote Reference |
|--|-------------------------------|
| Significant Accounting Matters | Note 1 |
| New Accounting Pronouncements | Note 2 |
| Rate Matters | Note 3 |
| Customer Choice and Industry Restructuring | Note 4 |
| Commitments and Contingencies | Note 5 |
| Guarantees | Note 6 |
| Company-wide Staffing and Budget Review | Note 7 |
| Benefit Plans | Note 9 |
| Business Segments | Note 11 |
| Financing Activities | Note 12 |

**INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES**

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

Second Quarter of 2006 Compared to Second Quarter of 2005

**Reconciliation of Second Quarter of 2005 to Second Quarter of 2006 Net Income
(in millions)**

| | | |
|---|------|-------------|
| Second Quarter of 2005 | \$ | 36 |
| Changes in Gross Margin: | | |
| Retail Margins | (18) | |
| Off-system Sales (a) | 16 | |
| Transmission Revenues | (9) | |
| Other | (4) | |
| Total Change in Gross Margin | | (15) |
| Changes in Operating Expenses and Other: | | |
| Other Operation and Maintenance | 8 | |
| Depreciation and Amortization | (2) | |
| Taxes Other Than Income Taxes | (3) | |
| Interest Expense | (1) | |
| Total Change in Operating Expenses and Other | | 2 |
| Income Tax Expense | | 6 |
| Second Quarter of 2006 | \$ | 29 |

(a) Includes firm wholesale sales to municipals and cooperatives.

Net Income decreased \$7 million to \$29 million in 2006. The key driver of the decrease was a \$15 million decrease in Gross Margin, partially offset by a \$6 million decrease in Income Tax Expense.

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

- Retail Margins decreased \$18 million primarily due to lower fuel recovery as fuel cost increases could not be recovered due to the Indiana fuel cap and a reduction in capacity settlement revenues of \$8 million under the Interconnection Agreement.
- Off-system Sales increased \$16 million primarily due to the addition of new municipal contracts including new rates and increased demand beginning January 2006.
- Transmission Revenues decreased \$9 million primarily due to the elimination of SECA revenues as of April 1, 2006 and a \$3 million provision for potential SECA refunds pending settlement negotiations with various intervenors. See the "SECA Revenue Subject to Refund" section of Note 3 - Rate Matters.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased \$8 million primarily due to a reduction in maintenance expenses for coal and nuclear generation facilities.

Income Taxes

Income Tax Expense decreased \$6 million primarily due to a decrease in pretax book income and changes in certain book/tax differences accounted for on a flow-through basis.

Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2005

Reconciliation of Six Months Ended June 30, 2005 to Six Months Ended June 30, 2006 Net Income (in millions)

| | |
|---|--------------|
| Six Months Ended June 30, 2005 | \$ 75 |
| Changes in Gross Margin: | |
| Retail Margins | (11) |
| Off-system Sales (a) | 29 |
| Transmission Revenues | (7) |
| Other | 9 |
| Total Change in Gross Margin | 20 |
| Changes in Operating Expenses and Other: | |
| Other Operation and Maintenance | 5 |
| Depreciation and Amortization | (4) |
| Taxes Other Than Income Taxes | (3) |
| Other Income (Expense), Net | (2) |
| Total Change in Operating Expenses and Other | (4) |
| Income Tax Expense | (5) |
| Six Months Ended June 30, 2006 | \$ 86 |

(a) Includes firm wholesale sales to municipals and cooperatives.

Net Income increased \$11 million to \$86 million in 2006. The key driver of the increase was a \$20 million increase in Gross Margin, partially offset by a \$5 million increase in Income Tax Expense.

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

- Retail Margins decreased \$11 million primarily due to lower fuel recovery as fuel cost increases could not be recovered due to the Indiana fuel cap and a reduction in capacity settlement revenues of \$5 million under the Interconnection Agreement.
- Off-system Sales increased \$29 million primarily due to the addition of new municipal contracts including new rates and increased demand beginning January 2006.
- Transmission Revenues decreased \$7 million primarily due to the elimination of SECA revenues as of April 1, 2006 and a \$3 million provision for potential SECA refunds pending

settlement negotiations with various intervenors. See the “SECA Revenue Subject to Refund” section of Note 3 - Rate Matters.

- Other increased \$9 million primarily due to increased River Transportation Division (RTD) revenues for barging coal and gains on sales of emission allowances. Related expenses which offset the RTD revenue increase are included in Other Operation on the Condensed Consolidated Statements of Income resulting in our earning only a return approved under regulatory order.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses decreased \$5 million primarily due to a reduction in distribution maintenance expense. Prior year distribution maintenance expense for overhead power lines included the costs of a January 2005 ice storm.

Income Taxes

Income Tax Expense increased \$5 million primarily due to an increase in pretax book income.

Financial Condition

Credit Ratings

The rating agencies currently have us on stable outlook. Current ratings, unchanged since first quarter of 2003, are as follows:

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

Cash Flow

Cash flows for the six months ended June 30, 2006 and 2005 were as follows:

| | 2006 | | 2005 | |
|---|-----------------------|-----------|-------------|-----------|
| | (in thousands) | | | |
| Cash and Cash Equivalents at Beginning of Period | \$ | 854 | \$ | 511 |
| Net Cash Flows From (Used For): | | | | |
| Operating Activities | | 291,722 | | 123,693 |
| Investing Activities | | (232,525) | | (159,964) |
| Financing Activities | | (59,517) | | 36,298 |
| Net Increase (Decrease) in Cash and Cash Equivalents | | (320) | | 27 |
| Cash and Cash Equivalents at End of Period | \$ | 534 | \$ | 538 |

Operating Activities

Net Cash Flows From Operating Activities were \$292 million in 2006. We produced Net Income of \$86 million during the period and a noncash expense item of \$89 million for Depreciation and Amortization. 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 working capital relates to a number of items; the most significant relates to Accounts Receivable, Net as we collected receivables from our affiliates related to power sales, settled litigation and emission allowances.

Net Cash Flows From Operating Activities were \$124 million in 2005. We produced Net Income of \$75 million during the period and a noncash expense item of \$85 million for Depreciation and Amortization. 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 activity in working capital relates to a number of items; the most significant relates to a \$69 million change in Accrued Taxes, Net reflecting taxes paid during 2005. We also contributed \$31 million to our pension trust.

Investing Activities

Net Cash Flows Used For Investing Activities during 2006 and 2005 primarily reflect our construction expenditures of \$169 million and \$120 million and acquisition of nuclear fuel of \$35 million and \$28 million, respectively. Construction expenditures for the nuclear plant and transmission and distribution assets are to upgrade or replace equipment and improve reliability. We also invested in capital projects to improve air quality and water intake systems. For the remainder of 2006, we expect Construction Expenditures of approximately \$160 million.

Financing Activities

Net Cash Flows Used For Financing Activities were \$60 million in 2006. We used cash from operations to repay Advances from Affiliates and pay common dividends. We also refinanced a series of pollution control bonds.

Net Cash Flows From Financing Activities were \$36 million in 2005. We retired \$61 million of preferred stock. Advances from Affiliates funded our construction expenditures.

Financing Activity

Long-term debt issuances and retirements during the first six months of 2006 were:

Issuances

| Type of Debt | Principal Amount (in thousands) | Interest Rate (%) | Due Date |
|-------------------------|--|-------------------------|-------------|
| Pollution Control Bonds | \$ 50,000 | Variable | 2025 |

Retirements

| Type of Debt | Principal Amount Paid (in thousands) | Interest Rate (%) | Due Date |
|-------------------------|---|-------------------------|-------------|
| Pollution Control Bonds | \$ 50,000 | 6.55 | 2025 |

Liquidity

We have solid investment grade ratings, which provide us ready access to capital markets in order to issue new debt or refinance long-term debt maturities. In addition, we participate in the Utility Money Pool, which provides access to AEP's liquidity.

Off-Balance Sheet Arrangements

Under a limited set of circumstances we enter into off-balance sheet arrangements to accelerate cash collections, reduce operational expenses and spread risk of loss to third parties. Our current guidelines restrict the use of off-balance sheet financing entities or structures to allow only traditional operating lease arrangements and sales of customer accounts receivable that are entered in the normal course of business. Our off-balance sheet arrangements have not changed significantly since year-end. For complete information on our off-balance sheet arrangements including the lease of Rockport Plant Unit 2 see "Off-balance Sheet Arrangements" in the "Management's Financial Discussion and Analysis" section of our 2005 Annual Report.

Summary Obligation Information

A summary of our contractual obligations is included in our 2005 Annual Report and has not changed significantly from year-end.

Significant Factors

Cook Plant Outage

On July 30, 2006, Unit 1 of our Cook Plant was taken off line due to elevated ambient temperatures in the containment building caused by a combination of high Lake Michigan water temperatures and partial blockage of cooling ventilation units. The Unit's operating license limits the containment building temperature to 120 degrees. Supplemental cooling units were installed on both units and will remain in place for the near future. Unit 1 returned to service on August 3, 2006.

Litigation and Regulatory Activity

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our pending litigation and regulatory proceedings, see Note 4 - Rate Matters, Note 6 - Customer Choice and Industry Restructuring and Note 7 - Commitments and Contingencies in our 2005 Annual Report. Also, see Note 3 - Rate Matters and Note 5 - Commitments and Contingencies in the "Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries" section. An adverse result in these proceedings has the potential to materially affect our results of operations, financial condition and cash flows.

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

Critical Accounting Estimates

See the “Critical Accounting Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” in the 2005 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES**Market Risks**

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

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our Condensed Consolidated Balance Sheet as of June 30, 2006 and the reasons for changes in our total MTM value as compared to December 31, 2005.

**Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheet
As of June 30, 2006
(in thousands)**

| | MTM Risk Management Contracts | Cash Flow & Fair Value Hedges | DETM Assignment (a) | Total |
|---|--|--|--------------------------------|------------------|
| Current Assets | \$ 43,070 | \$ 13,934 | \$ - | \$ 57,004 |
| Noncurrent Assets | 76,447 | 597 | - | 77,044 |
| Total MTM Derivative Contract Assets | 119,517 | 14,531 | - | 134,048 |
| Current Liabilities | (32,426) | (3,126) | (972) | (36,524) |
| Noncurrent Liabilities | (52,608) | - | (6,239) | (58,847) |
| Total MTM Derivative Contract Liabilities | (85,034) | (3,126) | (7,211) | (95,371) |
| Total MTM Derivative Contract Net Assets (Liabilities) | \$ 34,483 | \$ 11,405 | \$ (7,211) | \$ 38,677 |

(a) See "Natural Gas Contracts with DETM" section of Note 17 of the 2005 Annual Report.

**MTM Risk Management Contract Net Assets
Six Months Ended June 30, 2006
(in thousands)**

| | |
|---|------------------|
| Total MTM Risk Management Contract Net Assets at December 31, 2005 | \$ 33,932 |
| (Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period | 1,321 |
| Fair Value of New Contracts at Inception When Entered During the Period (a) | - |
| Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period | (682) |
| Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts | - |
| Changes in Fair Value Due to Market Fluctuations During the Period (b) | (1,356) |
| Changes Due to SIA (c) | (3,940) |

| | |
|---|------------------|
| Changes in Fair Value Allocated to Regulated Jurisdictions (d) | 5,208 |
| Total MTM Risk Management Contract Net Assets | 34,483 |
| Net Cash Flow & Fair Value Hedge Contracts | 11,405 |
| DETM Assignment (e) | (7,211) |
| Total MTM Risk Management Contract Net Assets at June 30, 2006 | \$ 38,677 |

- (a) 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.
- (b) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
- (c) See “Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement” section of Note 3.
- (d) “Changes in Fair Value Allocated to Regulated Jurisdictions” relates to the net gains (losses) of those contracts that are not reflected in our Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
- (e) See “Natural Gas Contracts with DETM” section of Note 17 of the 2005 Annual Report.

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

The following table presents:

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

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets Fair Value of Contracts as of June 30, 2006 (in thousands)

| | Remainder 2006 | 2007 | 2008 | 2009 | 2010 | After 2010 | Total |
|---|---------------------------|-----------------|-----------------|-----------------|-----------------|-----------------------|------------------|
| Prices Actively Quoted - Exchange Traded Contracts | \$ (2,096) | \$ 2,343 | \$ 2,398 | \$ - | \$ - | \$ - | 2,645 |
| Prices Provided by Other External Sources - OTC Broker Quotes (a) | 6,816 | 6,201 | 2,308 | 4,517 | - | - | 19,842 |
| Prices Based on Models and Other Valuation Methods (b) | 183 | 660 | 1,766 | 2,487 | 5,256 | 1,644 | 11,996 |
| Total | \$ 4,903 | \$ 9,204 | \$ 6,472 | \$ 7,004 | \$ 5,256 | \$ 1,644 | \$ 34,483 |

- (a) “Prices Provided by Other External Sources - OTC Broker Quotes” reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
- (b) “Prices Based on Models and Other Valuation Methods” is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying

commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

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

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

We employ the use of interest rate derivative transactions to manage interest rate risk related to existing variable rate debt and to manage interest rate exposure on anticipated borrowings of fixed-rate debt. We do not hedge all interest rate risk.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Condensed Consolidated Balance Sheets and the reasons for the changes from December 31, 2005 to June 30, 2006. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity Six Months Ended June 30, 2006 (in thousands)

| | Power | Interest Rate | Total |
|--|----------|---------------|------------|
| Beginning Balance in AOCI December 31, 2005 | \$ (877) | \$ (2,590) | \$ (3,467) |
| Changes in Fair Value | 6,619 | 1,532 | 8,151 |
| Impact due to Changes in SIA (a) | (267) | - | (267) |
| Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled | 657 | 160 | 817 |
| Ending Balance in AOCI June 30, 2006 | \$ 6,132 | \$ (898) | \$ 5,234 |

(a) See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 3.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a \$5,510 thousand gain.

Credit Risk

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

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at June 30, 2006, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

| | Six Months Ended June 30, 2006 (in thousands) | | | Twelve Months Ended December 31, 2005 (in thousands) | | | | |
|--|--|-------------|----------------|---|------------|-------------|-------|----------------|
| | End | High | Average | Low | End | High | | Average |
| | \$414 | \$968 | \$420 | \$242 | \$433 | \$720 | \$343 | \$124 |

VaR Associated with Debt Outstanding

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was \$80 million and \$55 million at June 30, 2006 and December 31, 2005, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

| | Three Months Ended | | Six Months Ended | |
|---|--------------------|------------------|------------------|------------------|
| | 2006 | 2005 | 2006 | 2005 |
| REVENUES | | | | |
| Electric Generation, Transmission and Distribution | \$ 371,581 | \$ 355,907 | \$ 775,350 | \$ 704,260 |
| Sales to AEP Affiliates | 80,401 | 81,544 | 168,935 | 174,082 |
| Other - Affiliated | 9,841 | 12,131 | 24,935 | 22,470 |
| Other - Nonaffiliated | 7,631 | 7,978 | 16,013 | 14,307 |
| TOTAL | 469,454 | 457,560 | 985,233 | 915,119 |
| EXPENSES | | | | |
| Fuel and Other Consumables for Electric Generation | 96,147 | 80,461 | 185,599 | 159,698 |
| Purchased Electricity for Resale | 15,533 | 12,730 | 26,543 | 24,002 |
| Purchased Electricity from AEP Affiliates | 80,830 | 71,984 | 167,252 | 145,993 |
| Other Operation | 115,506 | 115,910 | 232,712 | 220,312 |
| Maintenance | 40,352 | 48,366 | 85,571 | 102,688 |
| Depreciation and Amortization | 44,660 | 42,224 | 88,786 | 84,969 |
| Taxes Other Than Income Taxes | 18,965 | 16,296 | 37,871 | 34,978 |
| TOTAL | 411,993 | 387,971 | 824,334 | 772,640 |
| OPERATING INCOME | 57,461 | 69,589 | 160,899 | 142,479 |
| Other Income (Expense): | | | | |
| Interest Income | 663 | 418 | 1,357 | 851 |
| Allowance for Equity Funds Used During Construction | 1,440 | 1,040 | 3,364 | 2,689 |
| Interest Expense | (17,902) | (16,478) | (35,435) | (32,084) |
| INCOME BEFORE INCOME TAXES | 41,662 | 54,569 | 130,185 | 113,935 |
| Income Tax Expense | 13,137 | 18,976 | 43,782 | 38,673 |
| NET INCOME | 28,525 | 35,593 | 86,403 | 75,262 |
| Preferred Stock Dividend Requirements including Capital Stock Expense | 85 | 107 | 170 | 225 |
| EARNINGS APPLICABLE TO COMMON STOCK | \$ 28,440 | \$ 35,486 | \$ 86,233 | \$ 75,037 |

The common stock of I&M is wholly-owned by AEP.

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

| | Common Stock | Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total |
|--|-----------------|--------------------|----------------------|---|--------------|
| DECEMBER 31, 2004 | \$ 56,584 | \$ 858,835 | \$ 221,330 | \$ (45,251) | \$ 1,091,498 |
| Common Stock Dividends | | | (42,000) | | (42,000) |
| Preferred Stock Dividends | | | (169) | | (169) |
| Capital Stock Expense and Other | | 2,455 | (56) | | 2,399 |
| TOTAL | | | | | 1,051,728 |
| COMPREHENSIVE INCOME | | | | | |
| Other Comprehensive Loss, Net of Taxes: | | | | | |
| Cash Flow Hedges, Net of Tax of \$2,527 | | | | (4,692) | (4,692) |
| NET INCOME | | | 75,262 | | 75,262 |
| TOTAL COMPREHENSIVE INCOME | | | | | 70,570 |
| JUNE 30, 2005 | \$ 56,584 | \$ 861,290 | \$ 254,367 | \$ (49,943) | \$ 1,122,298 |
| DECEMBER 31, 2005 | \$ 56,584 | \$ 861,290 | \$ 305,787 | \$ (3,569) | \$ 1,220,092 |
| Common Stock Dividends | | | (20,000) | | (20,000) |
| Preferred Stock Dividends | | | (170) | | (170) |
| TOTAL | | | | | 1,199,922 |
| COMPREHENSIVE INCOME | | | | | |
| Other Comprehensive Income, Net of Taxes: | | | | | |
| Cash Flow Hedges, Net of Tax of \$4,685 | | | | 8,701 | 8,701 |
| NET INCOME | | | 86,403 | | 86,403 |
| TOTAL COMPREHENSIVE INCOME | | | | | 95,104 |
| JUNE 30, 2006 | \$ 56,584 | \$ 861,290 | \$ 372,020 | \$ 5,132 | \$ 1,295,026 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS

ASSETS

June 30, 2006 and December 31, 2005

(in thousands)

(Unaudited)

| | 2006 | 2005 |
|---|---------------------|---------------------|
| CURRENT ASSETS | | |
| Cash and Cash Equivalents | \$ 534 | \$ 854 |
| Accounts Receivable: | | |
| Customers | 61,036 | 62,614 |
| Affiliated Companies | 72,909 | 127,981 |
| Miscellaneous | 1,928 | 1,982 |
| Allowance for Uncollectible Accounts | (1,088) | (898) |
| Total Accounts Receivable | 134,785 | 191,679 |
| Fuel | 32,333 | 25,894 |
| Materials and Supplies | 123,692 | 118,039 |
| Risk Management Assets | 57,004 | 78,134 |
| Accrued Tax Benefits | 27,467 | 51,846 |
| Prepayments and Other | 6,031 | 31,303 |
| TOTAL | 381,846 | 497,749 |
| PROPERTY, PLANT AND EQUIPMENT | | |
| Electric: | | |
| Production | 3,216,765 | 3,128,078 |
| Transmission | 1,033,311 | 1,028,496 |
| Distribution | 1,073,159 | 1,029,498 |
| Other (including nuclear fuel and coal mining) | 478,450 | 465,130 |
| Construction Work in Progress | 288,913 | 311,080 |
| Total | 6,090,598 | 5,962,282 |
| Accumulated Depreciation, Depletion and Amortization | 2,875,115 | 2,822,558 |
| TOTAL - NET | 3,215,483 | 3,139,724 |
| OTHER NONCURRENT ASSETS | | |
| Regulatory Assets | 209,751 | 222,686 |
| Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds | 1,158,538 | 1,133,567 |
| Long-term Risk Management Assets | 77,044 | 103,645 |
| Deferred Charges and Other | 159,570 | 164,938 |
| TOTAL | 1,604,903 | 1,624,836 |
| TOTAL ASSETS | \$ 5,202,232 | \$ 5,262,309 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
June 30, 2006 and December 31, 2005
(Unaudited)

| | 2006 | 2005 |
|--|---------------------|---------------------|
| CURRENT LIABILITIES | (in thousands) | |
| Advances from Affiliates | \$ 57,749 | \$ 93,702 |
| Accounts Payable: | | |
| General | 135,405 | 139,334 |
| Affiliated Companies | 49,742 | 60,324 |
| Long-term Debt Due Within One Year | 414,632 | 364,469 |
| Risk Management Liabilities | 36,524 | 71,032 |
| Customer Deposits | 34,391 | 49,258 |
| Accrued Taxes | 60,444 | 56,567 |
| Other | 92,317 | 112,839 |
| TOTAL | 881,204 | 947,525 |
| | | |
| NONCURRENT LIABILITIES | | |
| Long-term Debt | 1,036,038 | 1,080,471 |
| Long-term Risk Management Liabilities | 58,847 | 86,159 |
| Deferred Income Taxes | 349,595 | 335,264 |
| Regulatory Liabilities and Deferred Investment Tax Credits | 684,865 | 710,015 |
| Asset Retirement Obligations | 761,890 | 737,959 |
| Deferred Credits and Other | 126,683 | 136,740 |
| TOTAL | 3,017,918 | 3,086,608 |
| | | |
| TOTAL LIABILITIES | 3,899,122 | 4,034,133 |
| | | |
| Cumulative Preferred Stock Not Subject to Mandatory Redemption | 8,084 | 8,084 |
| | | |
| Commitments and Contingencies (Note 5) | | |
| | | |
| COMMON SHAREHOLDER'S EQUITY | | |
| Common Stock - No Par Value: | | |
| Authorized - 2,500,000 Shares | | |
| Outstanding - 1,400,000 Shares | 56,584 | 56,584 |
| Paid-in Capital | 861,290 | 861,290 |
| Retained Earnings | 372,020 | 305,787 |
| Accumulated Other Comprehensive Income (Loss) | 5,132 | (3,569) |
| TOTAL | 1,295,026 | 1,220,092 |
| | | |
| TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY | \$ 5,202,232 | \$ 5,262,309 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Six Months Ended June 30, 2006 and 2005

(in thousands)

(Unaudited)

| | 2006 | 2005 |
|---|------------------|------------------|
| OPERATING ACTIVITIES | | |
| Net Income | \$ 86,403 | \$ 75,262 |
| Adjustments for Noncash Items: | | |
| Depreciation and Amortization | 88,786 | 84,969 |
| Accretion of Asset Retirement Obligations | 24,009 | 23,632 |
| Deferred Income Taxes | 9,562 | 3,476 |
| Deferred Investment Tax Credits | (3,640) | (3,664) |
| Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net | (12,111) | (758) |
| Amortization of Nuclear Fuel | 24,928 | 27,234 |
| Mark-to-Market of Risk Management Contracts | (634) | (5,598) |
| Pension Contributions to Qualified Plan Trusts | - | (30,701) |
| Change in Other Noncurrent Assets | 20,953 | 12,660 |
| Change in Other Noncurrent Liabilities | (9,308) | 2,533 |
| Changes in Components of Working Capital: | | |
| Accounts Receivable, Net | 56,894 | 25,058 |
| Fuel, Materials and Supplies | (12,092) | 561 |
| Accounts Payable | 4,221 | (11,426) |
| Accrued Taxes, Net | 28,256 | (68,896) |
| Customer Deposits | (14,867) | 5,713 |
| Other Current Assets | 21,921 | (3,646) |
| Other Current Liabilities | (21,559) | (12,716) |
| Net Cash Flows From Operating Activities | 291,722 | 123,693 |
| INVESTING ACTIVITIES | | |
| Construction Expenditures | (169,491) | (119,709) |
| Change in Advances to Affiliates, Net | - | 5,093 |
| Purchases of Investment Securities | (434,212) | (299,692) |
| Sales of Investment Securities | 405,716 | 272,654 |
| Acquisitions of Nuclear Fuel | (35,195) | (27,778) |
| Proceeds from Sales of Assets | 657 | 9,468 |
| Net Cash Flows Used For Investing Activities | (232,525) | (159,964) |
| FINANCING ACTIVITIES | | |
| Issuance of Long-term Debt | 49,745 | - |
| Change in Advances from Affiliates, Net | (35,953) | 143,126 |
| Retirement of Long-term Debt | (50,000) | - |
| Retirement of Cumulative Preferred Stock | - | (61,445) |
| Principal Payments for Capital Lease Obligations | (3,139) | (3,214) |
| Dividends Paid on Common Stock | (20,000) | (42,000) |
| Dividends Paid on Cumulative Preferred Stock | (170) | (169) |
| Net Cash Flows From (Used For) Financing Activities | (59,517) | 36,298 |

| | | | | |
|---|----|-------|----|-----|
| Net Increase (Decrease) in Cash and Cash Equivalents | | (320) | | 27 |
| Cash and Cash Equivalents at Beginning of Period | | 854 | | 511 |
| Cash and Cash Equivalents at End of Period | \$ | 534 | \$ | 538 |

SUPPLEMENTAL DISCLOSURE

| | | | | |
|--|----|--------|----|---------|
| Cash Paid for Interest, Net of Capitalized Amounts | \$ | 32,959 | \$ | 29,427 |
| Cash Paid for Income Taxes, Net of Refunds | | 12,031 | | 106,891 |
| Noncash Acquisitions Under Capital Leases | | 3,185 | | 652 |
| Construction Expenditures Included in Accounts Payable at June 30, | | 18,031 | | 14,640 |
| Acquisition of Nuclear Fuel in Accounts Payable at June 30, | | 25,780 | | - |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
INDEX TO CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT
SUBSIDIARIES

The condensed notes to I&M's condensed consolidated financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to I&M.

| | Footnote Reference |
|---|-------------------------------|
| Significant Accounting Matters | Note 1 |
| New Accounting Pronouncements | Note 2 |
| Rate Matters | Note 3 |
| Commitments and Contingencies | Note 5 |
| Guarantees | Note 6 |
| Company-wide Staffing and Budget Review | Note 7 |
| Benefit Plans | Note 9 |
| Business Segments | Note 11 |
| Financing Activities | Note 12 |

KENTUCKY POWER COMPANY

KENTUCKY POWER COMPANY
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

Second Quarter of 2006 Compared to Second Quarter of 2005

**Reconciliation of Second Quarter of 2005 to Second Quarter of 2006 Net Income
(in millions)**

| | | |
|--|-----|-----|
| Second Quarter of 2005 | \$ | 2 |
| Changes in Gross Margin: | | |
| Retail Margins | 10 | |
| Off-system Sales | 1 | |
| Transmission Revenues | (4) | |
| Other | (2) | |
| Total Change in Gross Margin | | 5 |
| Total Change in Operating Expenses and Other | | (1) |
| Income Tax Expense | | (1) |
| Second Quarter of 2006 | \$ | 5 |

Net Income increased \$3 million in the second quarter of 2006. The key driver of the increase was a \$5 million increase in Gross Margin.

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

- Retail Margins increased \$10 million primarily due to rate relief from the March 2006 approval of the settlement agreement in our base rate case.
- Transmission Revenues decreased \$4 million primarily due to the elimination of SECA revenues as of April 1, 2006 and a \$1 million provision for potential SECA refunds pending settlement negotiations with various intervenors. See the "SECA Revenue Subject to Refund" section of Note 3 - Rate Matters.

Income Taxes

The increase in Income Tax Expense of \$1 million is primarily due to an increase in pretax book income, offset in part by a decrease in state income taxes.

Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2005

Reconciliation of Six Months Ended June 30, 2005 to Six Months Ended June 30, 2006 Net Income

(in millions)

| | | |
|---|----|------------|
| Six Months Ended June 30, 2005 | \$ | 12 |
| Changes in Gross Margin: | | |
| Retail Margins | | 6 |
| Off-system Sales | | 1 |
| Transmission Revenues | | (3) |
| Other | | 3 |
| Total Change in Gross Margin | | 7 |
| Changes in Operating Expenses and Other: | | |
| Other Operation and Maintenance | | (1) |
| Depreciation and Amortization | | (1) |
| Total Change in Operating Expenses and Other | | (2) |
| Income Tax Expense | | (2) |
| Six Months Ended June 30, 2006 | \$ | 15 |

Net Income increased by \$3 million in 2006. The key driver of the increase was a \$7 million increase in Gross Margin.

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

- Retail Margins increased \$6 million primarily due to rate relief from the March 2006 approval of the settlement agreement in our base rate case as well as favorable financial transmission rights revenue. The above was partially offset by increased capacity charges due to changes in the relative peak demands and generating capacity of the AEP Power Pool members.
- Transmission Revenues decreased \$3 million primarily due to the elimination of SECA revenues as of April 1, 2006 and a \$1 million provision for potential SECA refunds pending settlement negotiations with various intervenors. See the "SECA Revenue Subject to Refund" section of Note 3 - Rate Matters.
- Other revenues increased \$3 million due primarily to a \$3 million unfavorable adjustment of the Demand Side Management Program regulatory asset in March 2005.

Income Taxes

The increase in Income Tax Expense of \$2 million is primarily due to an increase in pretax book income and changes in certain book/tax differences accounted for on a flow-through basis.

Financial Condition

Credit Ratings

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

Moody's S&P Fitch

Senior Unsecured Baa2 BBB BBB
Debt

Financing Activities

Long-term debt issuances and retirements during the first six months of 2006 were:

Issuances

None

Retirements

| Type of Debt | Principal Amount (in thousands) | Interest Rate (%) | Due Date |
|--------------------------|---------------------------------------|-------------------------|-------------|
| Notes Payable-Affiliated | \$ 40,000 | 6.501 | 2006 |

Liquidity

We have solid investment grade ratings, which provide us ready access to capital markets in order to issue new debt or refinance long-term debt maturities. In addition, we participate in the Utility Money Pool, which provides access to AEP's liquidity.

Summary Obligation Information

A summary of our contractual obligations is included in our 2005 Annual Report and has not changed significantly from year-end.

Significant Factors

Big Sandy Plant Scrubber

Completion of construction of a scrubber at our Big Sandy Plant was previously scheduled for 2010. We suspended the project in the second quarter of 2006 after a generation engineering evaluation determined that there was a substantially higher estimated capital cost due to increases in labor and material costs, refinements of preliminary costs estimates and an increase in cost per ton of removed SO₂. We currently expect the project to resume in mid-2010.

Because the project has a planned restart date, the total project expenditures of \$16 million were transferred during the second quarter of 2006 from Construction Work in Progress to Deferred Charges and Other on our Condensed Balance Sheet. If management does not resume the project, the balance of incurred expenditures would negatively impact future earnings unless a regulatory asset could be established due to probable recovery through rates.

Our 2006 estimated construction expenditures of \$100 million, as reported in Note 7 - Commitments and Contingencies in our 2005 Annual Report, has been revised to \$54 million due to the delay of the project, of which \$15 million has been expended during the first six months of the year.

Litigation and Regulatory Activity

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our pending litigation and regulatory proceedings, see Note 4 - Rate Matters and Note 7 - Commitments and Contingencies in our 2005 Annual Report. Also, see Note 3 - Rate Matters and Note 5 - Commitments and Contingencies in the “Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries” section. An adverse result in these proceedings has the potential to materially affect our results of operations, financial condition and cash flows.

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

Critical Accounting Estimates

See the “Critical Accounting Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” in the 2005 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES**Market Risks**

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

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our condensed balance sheet as of June 30, 2006 and the reasons for changes in our total MTM value as compared to December 31, 2005.

**Reconciliation of MTM Risk Management Contracts to
Condensed Balance Sheet
As of June 30, 2006
(in thousands)**

| | MTM Risk Management Contracts | Cash Flow & Fair Value Hedges | DETM Assignment (a) | Total |
|---|--|--|--------------------------------|------------------|
| Current Assets | \$ 17,224 | \$ 4,457 | \$ - | \$ 21,681 |
| Noncurrent Assets | 30,424 | 237 | - | 30,661 |
| Total MTM Derivative Contract Assets | 47,648 | 4,694 | - | 52,342 |
| Current Liabilities | (13,106) | (1,671) | (386) | (15,163) |
| Noncurrent Liabilities | (21,068) | (484) | (2,477) | (24,029) |
| Total MTM Derivative Contract Liabilities | (34,174) | (2,155) | (2,863) | (39,192) |
| Total MTM Derivative Contract Net Assets (Liabilities) | \$ 13,474 | \$ 2,539 | \$ (2,863) | \$ 13,150 |

(a) See "Natural Gas Contracts with DETM" section of Note 17 of the 2005 Annual Report.

**MTM Risk Management Contract Net Assets
Six Months Ended June 30, 2006
(in thousands)**

| | |
|---|------------------|
| Total MTM Risk Management Contract Net Assets at December 31, 2005 | \$ 13,518 |
| (Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period | 681 |
| Fair Value of New Contracts at Inception When Entered During the Period (a) | - |
| Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period | (290) |
| Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts | - |
| Changes in Fair Value Due to Market Fluctuations During the Period (b) | (688) |
| Changes Due to SIA (c) | (1,565) |
| Changes in Fair Value Allocated to Regulated Jurisdictions (d) | 1,818 |

| | |
|---|------------------|
| Total MTM Risk Management Contract Net Assets | 13,474 |
| Net Cash Flow & Fair Value Hedge Contracts | 2,539 |
| DETM Assignment (e) | (2,863) |
| Total MTM Risk Management Contract Net Assets at June 30, 2006 | \$ 13,150 |

- (a) 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.
- (b) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
- (c) See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 3.
- (d) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
- (e) See "Natural Gas Contracts with DETM" section of Note 17 of the 2005 Annual Report.

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

The following table presents:

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

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets Fair Value of Contracts as of June 30, 2006 (in thousands)

| | Remainder | | | | | After | |
|---|------------------|-----------------|-----------------|-----------------|-----------------|---------------|------------------|
| | 2006 | 2007 | 2008 | 2009 | 2010 | 2010 | Total |
| Prices Actively Quoted - Exchange Traded Contracts | \$ (832) | \$ 930 | \$ 952 | \$ - | \$ - | \$ - | 1,050 |
| Prices Provided by Other External Sources - OTC Broker Quotes (a) | 2,691 | 2,434 | 923 | 1,794 | - | - | 7,842 |
| Prices Based on Models and Other Valuation Methods (b) | 67 | 147 | 641 | 987 | 2,087 | 653 | 4,582 |
| Total | \$ 1,926 | \$ 3,511 | \$ 2,516 | \$ 2,781 | \$ 2,087 | \$ 653 | \$ 13,474 |

- (a) "Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
- (b) "Prices Based on Models and Other Valuation Methods" is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition,

where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

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

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

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

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Condensed Balance Sheets and the reasons for the changes from December 31, 2005 to June 30, 2006. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity Six Months Ended June 30, 2006 (in thousands)

| | Power | Interest Rate | Total |
|---|----------|---------------|----------|
| Beginning Balance in AOCI December 31, 2005 | \$ (352) | \$ 158 | \$ (194) |
| Changes in Fair Value | 2,632 | - | 2,632 |
| Impact Due to Changes in SIA (a) | (106) | - | (106) |
| Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled | 262 | (44) | 218 |
| Ending Balance in AOCI June 30, 2006 | \$ 2,436 | \$ 114 | \$ 2,550 |

(a) See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 3.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a \$2,367 thousand gain.

Credit Risk

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

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at June 30, 2006, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

| Six Months Ended June 30, 2006 (in thousands) | | | | Twelve Months Ended December 31, 2005 (in thousands) | | | |
|--|-------------|----------------|------------|---|-------------|----------------|------------|
| End | High | Average | Low | End | High | Average | Low |
| \$164 | \$385 | \$167 | \$96 | \$174 | \$289 | \$138 | \$50 |

VaR Associated with Debt Outstanding

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was \$12 million and \$13 million at June 30, 2006 and December 31, 2005, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or financial position.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

| | Three Months Ended | | Six Months Ended | |
|--|--------------------|-----------------|------------------|------------------|
| | 2006 | 2005 | 2006 | 2005 |
| REVENUES | | | | |
| Electric Generation, Transmission and Distribution | \$ 121,074 | \$ 108,510 | \$ 258,694 | \$ 217,591 |
| Sales to AEP Affiliates | 14,109 | 13,709 | 28,077 | 32,257 |
| Other | 120 | 490 | 379 | 921 |
| TOTAL | 135,303 | 122,709 | 287,150 | 250,769 |
| EXPENSES | | | | |
| Fuel and Other Consumables for Electric Generation | 31,790 | 31,989 | 75,756 | 60,668 |
| Purchased Electricity for Resale | 1,991 | 1,786 | 2,964 | 3,910 |
| Purchased Electricity from AEP Affiliates | 50,923 | 43,010 | 100,449 | 85,749 |
| Other Operation | 13,738 | 14,255 | 27,486 | 28,197 |
| Maintenance | 9,293 | 8,482 | 16,434 | 14,398 |
| Depreciation and Amortization | 11,572 | 11,225 | 23,029 | 22,377 |
| Taxes Other Than Income Taxes | 2,442 | 2,219 | 4,954 | 4,644 |
| TOTAL | 121,749 | 112,966 | 251,072 | 219,943 |
| OPERATING INCOME | 13,554 | 9,743 | 36,078 | 30,826 |
| Other Income | 105 | 207 | 372 | 439 |
| Interest Expense | (7,440) | (7,068) | (14,736) | (14,438) |
| INCOME BEFORE INCOME TAXES | 6,219 | 2,882 | 21,714 | 16,827 |
| Income Tax Expense | 1,168 | 436 | 6,833 | 4,496 |
| NET INCOME | \$ 5,051 | \$ 2,446 | \$ 14,881 | \$ 12,331 |

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

| | Common Stock | Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total |
|--|-----------------|--------------------|----------------------|---|------------|
| DECEMBER 31, 2004 | \$ 50,450 | \$ 208,750 | \$ 70,555 | \$ (8,775) | \$ 320,980 |
| COMPREHENSIVE INCOME | | | | | |
| Other Comprehensive Loss, Net of Taxes: | | | | | |
| Cash Flow Hedges, Net of Tax of \$1,053 | | | | (1,956) | (1,956) |
| NET INCOME | | | 12,331 | | 12,331 |
| TOTAL COMPREHENSIVE INCOME | | | | | 10,375 |
| JUNE 30, 2005 | \$ 50,450 | \$ 208,750 | \$ 82,886 | \$ (10,731) | \$ 331,355 |
| DECEMBER 31, 2005 | \$ 50,450 | \$ 208,750 | \$ 88,864 | \$ (223) | \$ 347,841 |
| Common Stock Dividends | | | (5,000) | | (5,000) |
| TOTAL | | | | | 342,841 |
| COMPREHENSIVE INCOME | | | | | |
| Other Comprehensive Income, Net of Taxes: | | | | | |
| Cash Flow Hedges, Net of Tax of \$1,478 | | | | 2,744 | 2,744 |
| NET INCOME | | | 14,881 | | 14,881 |
| TOTAL COMPREHENSIVE INCOME | | | | | 17,625 |
| JUNE 30, 2006 | \$ 50,450 | \$ 208,750 | \$ 98,745 | \$ 2,521 | \$ 360,466 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

**KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS**

ASSETS

June 30, 2006 and December 31, 2005

(in thousands)

(Unaudited)

| | 2006 | 2005 |
|---|---------------------|---------------------|
| CURRENT ASSETS | | |
| Cash and Cash Equivalents | \$ 432 | \$ 526 |
| Accounts Receivable: | | |
| Customers | 27,009 | 26,533 |
| Affiliated Companies | 13,884 | 23,525 |
| Accrued Unbilled Revenues | 3,322 | 6,311 |
| Miscellaneous | 715 | 35 |
| Allowance for Uncollectible Accounts | (211) | (147) |
| Total Accounts Receivable | 44,719 | 56,257 |
| Fuel | 15,924 | 8,490 |
| Materials and Supplies | 9,170 | 10,181 |
| Risk Management Assets | 21,681 | 31,437 |
| Accrued Tax Benefits | 4,539 | 6,598 |
| Margin Deposits | 250 | 6,895 |
| Prepayments and Other | 1,352 | 6,324 |
| TOTAL | 98,067 | 126,708 |
| PROPERTY, PLANT AND EQUIPMENT | | |
| Electric: | | |
| Production | 475,177 | 472,575 |
| Transmission | 389,766 | 386,945 |
| Distribution | 465,343 | 456,063 |
| Other | 61,465 | 63,382 |
| Construction Work in Progress | 25,591 | 35,461 |
| Total | 1,417,342 | 1,414,426 |
| Accumulated Depreciation and Amortization | 433,097 | 425,817 |
| TOTAL - NET | 984,245 | 988,609 |
| OTHER NONCURRENT ASSETS | | |
| Regulatory Assets | 110,275 | 117,432 |
| Long-term Risk Management Assets | 30,661 | 41,810 |
| Deferred Charges and Other | 56,947 | 45,467 |
| TOTAL | 197,883 | 204,709 |
| TOTAL ASSETS | \$ 1,280,195 | \$ 1,320,026 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
June 30, 2006 and December 31, 2005
(Unaudited)

| | 2006 | 2005 |
|--|---------------------|---------------------|
| CURRENT LIABILITIES | (in thousands) | |
| Advances from Affiliates | \$ 36,991 | \$ 6,040 |
| Accounts Payable: | | |
| General | 29,393 | 32,454 |
| Affiliated Companies | 22,677 | 29,326 |
| Long-term Debt Due Within One Year - Affiliated | - | 39,771 |
| Risk Management Liabilities | 15,163 | 28,770 |
| Customer Deposits | 15,975 | 21,643 |
| Accrued Taxes | 9,926 | 8,805 |
| Accrued Interest | 7,419 | 7,428 |
| Other | 11,483 | 14,096 |
| TOTAL | 149,027 | 188,333 |
| NONCURRENT LIABILITIES | | |
| Long-term Debt - Nonaffiliated | 427,354 | 427,219 |
| Long-term Debt - Affiliated | 20,000 | 20,000 |
| Long-term Risk Management Liabilities | 24,029 | 35,302 |
| Deferred Income Taxes | 241,482 | 234,719 |
| Regulatory Liabilities and Deferred Investment Tax Credits | 48,434 | 56,794 |
| Deferred Credits and Other | 9,403 | 9,818 |
| TOTAL | 770,702 | 783,852 |
| TOTAL LIABILITIES | 919,729 | 972,185 |
| Commitments and Contingencies (Note 5) | | |
| COMMON SHAREHOLDER'S EQUITY | | |
| Common Stock - \$50 Par Value Per Share: | | |
| Authorized - 2,000,000 Shares | | |
| Outstanding - 1,009,000 Shares | 50,450 | 50,450 |
| Paid-in Capital | 208,750 | 208,750 |
| Retained Earnings | 98,745 | 88,864 |
| Accumulated Other Comprehensive Income (Loss) | 2,521 | (223) |
| TOTAL | 360,466 | 347,841 |
| TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY | \$ 1,280,195 | \$ 1,320,026 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

| | 2006 | 2005 |
|---|-----------------|-----------------|
| OPERATING ACTIVITIES | | |
| Net Income | \$ 14,881 | \$ 12,331 |
| Adjustments for Noncash Items: | | |
| Depreciation and Amortization | 23,029 | 22,377 |
| Deferred Income Taxes | 3,044 | 2,482 |
| Mark-to-Market of Risk Management Contracts | (25) | (3,330) |
| Pension Contributions to Qualified Plan Trusts | - | (6,092) |
| Over/Under Fuel Recovery | 3,173 | (7,181) |
| Change in Other Noncurrent Assets | 1,898 | 1,611 |
| Change in Other Noncurrent Liabilities | 1,396 | 4,483 |
| Changes in Components of Working Capital: | | |
| Accounts Receivable, Net | 11,538 | 7,653 |
| Fuel, Materials and Supplies | (6,423) | (2,830) |
| Accounts Payable | (7,679) | 10,926 |
| Accrued Taxes, Net | 3,180 | (1,531) |
| Customer Deposits | (5,668) | 3,995 |
| Other Current Assets | 8,531 | (2,340) |
| Other Current Liabilities | (1,993) | (1,695) |
| Net Cash Flows From Operating Activities | 48,882 | 40,859 |
| INVESTING ACTIVITIES | | |
| Construction Expenditures | (34,458) | (23,450) |
| Change in Advances to Affiliates, Net | - | 3,480 |
| Other | 191 | (1) |
| Net Cash Flows Used For Investing Activities | (34,267) | (19,971) |
| FINANCING ACTIVITIES | | |
| Change in Advances from Affiliates, Net | 30,951 | - |
| Retirement of Long-term Debt - Affiliated | (40,000) | (20,000) |
| Principal Payments for Capital Lease Obligations | (660) | (782) |
| Dividends Paid on Common Stock | (5,000) | - |
| Net Cash Flows Used For Financing Activities | (14,709) | (20,782) |
| Net Increase (Decrease) in Cash and Cash | | |
| Equivalents | (94) | 106 |
| Cash and Cash Equivalents at Beginning of Period | 526 | 132 |
| Cash and Cash Equivalents at End of Period | \$ 432 | \$ 238 |
| SUPPLEMENTARY INFORMATION | | |
| Cash Paid for Interest, Net of Capitalized Amounts | \$ 14,543 | \$ 13,942 |
| Cash Paid for Income Taxes, Net of Refunds | 185 | 3,761 |
| Noncash Acquisitions Under Capital Leases | 485 | 230 |
| | 4,522 | 2,107 |

Construction Expenditures Included in Accounts
Payable at June 30,

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

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

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

| | Footnote Reference |
|---|-------------------------------|
| Significant Accounting Matters | Note 1 |
| New Accounting Pronouncements | Note 2 |
| Rate Matters | Note 3 |
| Commitments and Contingencies | Note 5 |
| Guarantees | Note 6 |
| Company-wide Staffing and Budget Review | Note 7 |
| Benefit Plans | Note 9 |
| Business Segments | Note 11 |
| Financing Activities | Note 12 |

OHIO POWER COMPANY CONSOLIDATED

**OHIO POWER COMPANY CONSOLIDATED
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS**

Results of Operations

Second Quarter of 2006 Compared to Second Quarter of 2005

**Reconciliation of Second Quarter of 2005 to Second Quarter of 2006 Net Income
(in millions)**

| | | |
|---|------|-------------|
| Second Quarter of 2005 | \$ | 71 |
| Changes in Gross Margin: | | |
| Retail Margins | (30) | |
| Off-system Sales | 3 | |
| Transmission Revenues | (12) | |
| Other | 8 | |
| Total Change in Gross Margin | | (31) |
| Changes in Operating Expenses and Other: | | |
| Other Operation and Maintenance | (37) | |
| Depreciation and Amortization | 2 | |
| Taxes Other Than Income Taxes | (5) | |
| Carrying Costs Income | (4) | |
| Interest Expense | 2 | |
| Total Change in Operating Expenses and Other | | (42) |
| Income Tax Expense | | 25 |
| Second Quarter of 2006 | \$ | 23 |

Net Income decreased \$48 million to \$23 million in 2006. The key drivers of the decrease were a \$31 million decrease in Gross Margin and a \$42 million increase in Operating Expenses and Other, partially offset by a \$25 million decrease in Income Tax Expense.

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

- Retail Margins decreased \$30 million primarily due to a decrease in retail revenue primarily related to the transfer of two industrial customers to APCo and mild weather, increased delivered fuel costs and the receipt of SO₂ allowances from Buckeye Power, Inc. under the Cardinal Station Allowance Agreement in the second quarter of 2005. The decrease was partially offset by the Rate Stabilization Plan (RSP) rate increase effective January 1, 2006.
- Transmission Revenues decreased \$12 million primarily due to the elimination of SECA revenues as of April 1, 2006 and a \$4 million provision for potential SECA refunds pending settlement negotiations with various intervenors. See the "SECA Revenue Subject to Refund" section of Note 3 - Rate Matters.

Other revenues increased \$8 million partially due to an increase in Cook Coal Terminal (CCT) revenues. Related expenses, which offset the CCT revenue increase, are included in Other Operation on the Condensed Consolidated Statements of Income.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance Expense increased \$37 million primarily due to an increase in maintenance from planned and forced outages at the Gavin, Muskingum, Kammer, and Sporn plants related to major boiler overhauls, boiler tube inspections and related removal costs.
- Taxes Other Than Income Taxes increased \$5 million primarily due to an increase in property taxes.
- Carrying Costs Income decreased \$4 million primarily due to the completion of the establishment of a regulatory asset for environmental carrying costs from 2004 and 2005 that are now recovered during 2006 through 2008 according to the RSP.

Income Taxes

The decrease in Income Tax Expense of \$25 million is primarily due to a decrease in pretax book income.

Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2005

Reconciliation of Six Months Ended June 30, 2005 to Six Months Ended June 30, 2006 Net Income (in millions)

| | |
|---|---------------|
| Six Months Ended June 30, 2005 | \$ 171 |
| Changes in Gross Margin: | |
| Retail Margins | (5) |
| Off-system Sales | 6 |
| Transmission Revenues | (10) |
| Other | 11 |
| Total Change in Gross Margin | 2 |
| Changes in Operating Expenses and Other: | |
| Other Operation and Maintenance | (60) |
| Depreciation and Amortization | (3) |
| Taxes Other than Income Taxes | (4) |
| Carrying Costs Income | (23) |
| Interest Expense | 4 |
| Total Change in Operating Expenses and Other | (86) |
| Income Tax Expense | 31 |
| Six Months Ended June 30, 2006 | \$ 118 |

Net Income decreased \$53 million to \$118 million in 2006. The key driver of the decrease was an \$86 million increase in Operating Expenses and Other, partially offset by a \$31 million decrease in Income Tax Expense.

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

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- Retail Margins decreased \$5 million primarily due to an increase in delivered fuel costs, decreased capacity settlement receipts under the Interconnection Agreement related to an increase in the generating capacity of the AEP Power Pool members and the transfer of two industrial customers to APCo. The decrease was partially offset by the RSP rate increase effective January 1, 2006.
- Off-System Sales increased \$6 million primarily due to an increase in AEP Power Pool physical sales partially offset by lower optimization activities.
- Transmission Revenues decreased \$10 million primarily due to the elimination of SECA revenues as of April 1, 2006 and a \$4 million provision for potential SECA refunds pending settlement negotiations with various intervenors. See the "SECA Revenue Subject to Refund" section of Note 3 - Rate Matters.
- Other revenues increased \$11 million partially due to an increase in gains on sales of emission allowances to affiliates.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expense increased \$60 million primarily due to an increase in maintenance from planned and forced outages at the Gavin, Muskingum, Kammer, and Sporn plants related to major boiler overhauls, boiler tube inspections and related removal costs and the establishment of a regulatory asset for PJM administrative fees which reduced expenses in the prior period, partially offset by major ice storm expense incurred in the prior period.
- Taxes Other Than Income Taxes increased \$4 million primarily due to an increase in property taxes.
- Carrying Costs Income decreased \$23 million primarily due to the completion of the establishment of a regulatory asset for environmental carrying costs from 2004 and 2005 that are recovered during 2006 through 2008 according to the RSP. We recorded \$16 million in environmental carrying costs in the first quarter of 2005 related to 2004.
- Interest Expense decreased \$4 million primarily due to an increase in allowance for borrowed funds used during construction partially offset by interest on long-term debt issuances subsequent to June 2005 and an increase in advances from affiliate.

Income Taxes

The decrease in Income Tax Expense of \$31 million is primarily due to a decrease in pretax book income.

Financial Condition

Credit Ratings

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

| | Moody's | S&P | Fitch |
|-----------------------|----------------|----------------|--------------|
| Senior Unsecured Debt | A3 | BBB | BBB+ |

Cash Flow

Cash flows for the six months ended June 30, 2006 and 2005 were as follows:

| 2006 | 2005 |
|-----------------------|-------------|
| (in thousands) | |

| | | | | |
|---|----|-----------|----|-----------|
| Cash and Cash Equivalents at Beginning of Period | \$ | 1,240 | \$ | 9,337 |
| Net Cash Flows From (Used For): | | | | |
| Operating Activities | | 326,354 | | 179,555 |
| Investing Activities | | (516,878) | | (155,651) |
| Financing Activities | | 190,274 | | (31,887) |
| Net Decrease in Cash and Cash Equivalents | | (250) | | (7,983) |
| Cash and Cash Equivalents at End of Period | \$ | 990 | \$ | 1,354 |

Operating Activities

Net Cash Flows From Operating Activities were \$326 million in 2006. We produced Net Income of \$118 million during the period and a noncash expense item of \$157 million for Depreciation and Amortization. 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 working capital primarily relates to three items, Accounts Receivable, Net, Fuel, Materials and Supplies, and Accounts Payable. Accounts Receivable, Net decreased \$98 million due to collected receivables from our affiliates related to power sales, settled litigation and emission allowances. Fuel, Materials and Supplies increased \$56 million primarily due to an increase in coal inventory in preparation for the summer cooling season. Accounts Payable decreased \$43 million primarily due to timing differences for payments to affiliates related to the AEP Power Pool.

Net Cash Flows From Operating Activities were \$180 million in 2005. We produced Net Income of \$171 million during the period and a noncash expense item of \$154 million for Depreciation and Amortization. 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 working capital primarily relates to a \$93 million decrease in Accrued Taxes due to 2004 tax payments made in the second quarter of 2005 for federal income tax and personal property tax.

Investing Activities

Net Cash Flows Used For Investing Activities during 2006 and 2005 primarily reflect our Construction Expenditures of \$482 million and \$289 million, respectively, for environmental upgrades, as well as projects to improve service reliability for transmission and distribution. In 2005, Construction Expenditures of \$289 million were offset by a decrease in Advances to Affiliates, Net. For the remainder of 2006, we expect our Construction Expenditures to be approximately \$580 million.

Financing Activities

Net Cash Flows From Financing Activities were \$190 million for 2006. We issued a Senior Unsecured Note for \$350 million and incurred obligations of \$65 million relating to Pollution Control Bonds. We retired Notes Payable-Affiliated of \$200 million. We repaid Advances from Affiliates of \$70 million and received a capital contribution from our parent of \$70 million.

Net Cash Flows Used For Financing Activities were \$32 million for 2005. We issued Installment Purchase Contracts for \$218 million. We retired Installment Purchase Contracts of \$218 million. We paid common stock dividends of \$15 million.

Financing Activity

Long-term debt issuances and retirements during the first six months of 2006 were:

Issuances

| Type of Debt | Principal Amount (in thousands) | Interest Rate (%) | Due Date |
|-------------------------|------------------------------------|----------------------|----------|
| Pollution Control Bonds | \$ 65,000 | Variable | 2036 |
| Senior Unsecured Note | 350,000 | 6.00 | 2016 |

Retirements and Principal Payments

| Type of Debt | Principal Amount (in thousands) | Interest Rate (%) | Due Date |
|-------------------------------|------------------------------------|----------------------|----------|
| Notes Payable | \$ 2,927 | 6.81 | 2008 |
| Notes Payable | 3,250 | 6.27 | 2009 |
| Notes Payable - Affiliated | 200,000 | 3.32 | 2006 |

Liquidity

We have solid investment grade ratings, which provide us ready access to capital markets in order to issue new debt, refinance short-term debt or refinance long-term debt maturities. In addition, we participate in the Utility Money Pool, which provides access to AEP's liquidity.

Summary Obligation Information

A summary of our contractual obligations is included in our 2005 Annual Report and has not changed significantly from year-end, other than the debt issuances, retirements and principal payments discussed above.

Significant Factors***Litigation and Regulatory Activity***

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our pending litigation and regulatory proceedings, see Note 4 - Rate Matters, Note 6 - Customer Choice and Industry Restructuring and Note 7 - Commitments and Contingencies in our 2005 Annual Report. Also, see Note 3 - Rate Matters, Note 4 - Customer Choice and Industry Restructuring and Note 5 - Commitments and Contingencies in the "Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries" section. An adverse result in these proceedings has the potential to materially affect our results of operations, financial condition and cash flows.

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

Muskingum River Project Deferral (Effective in the third quarter of 2006)

Completion of construction of the Muskingum River Unit 5 flue gas desulphurization (FGD) project was previously scheduled for 2008. We suspended the project in the third quarter of 2006 following a review of a new sulfur dioxide and mercury compliance plan evaluation, updated coal market information reflecting the contraction of the low sulfur versus high sulfur price differentials and the latest project costs. We will continue the landfill engineering and design to completion (December 2006), which includes land acquisition and required environmental studies. We currently expect the project to have an in-service date of December 31, 2010.

Our costs incurred through June 30, 2006 total approximately \$35 million. Because the project has a planned restart date, the total project expenditures will transfer during the third quarter of 2006 from Construction Work in Progress to Deferred Charges and Other on our Condensed Consolidated Balance Sheet. There will be no change in the second quarter of 2006 to the recorded construction work in progress amount because the suspension was not approved until July 2006. In addition to the costs-to-date, certain project items including the landfill, a warehouse and buildings are planned to be completed through December 2006 and total approximately \$8 million. If management does not resume the project, the balance of incurred expenditures would negatively impact future earnings unless a regulatory asset could be established due to probable recovery through rates.

Critical Accounting Estimates

See the “Critical Accounting Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” in the 2005 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES**Market Risks**

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

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our condensed balance sheet as of June 30, 2006 and the reasons for changes in our total MTM value as compared to December 31, 2005.

**Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheet
As of June 30, 2006
(in thousands)**

| | MTM Risk Management Contracts | Cash Flow Hedges | DETM Assignment (a) | Total |
|---|--|-----------------------------|--------------------------------|------------------|
| Current Assets | \$ 58,410 | \$ 14,156 | \$ - | \$ 72,566 |
| Noncurrent Assets | 97,794 | 753 | - | 98,547 |
| Total MTM Derivative Contract Assets | 156,204 | 14,909 | - | 171,113 |
| Current Liabilities | (47,796) | (3,033) | (1,226) | (52,055) |
| Noncurrent Liabilities | (69,493) | - | (7,868) | (77,361) |
| Total MTM Derivative Contract Liabilities | (117,289) | (3,033) | (9,094) | (129,416) |
| Total MTM Derivative Contract Net Assets (Liabilities) | \$ 38,915 | \$ 11,876 | \$ (9,094) | \$ 41,697 |

(a) See "Natural Gas Contracts with DETM" section of Note 17 in the 2005 Annual Report.

**MTM Risk Management Contract Net Assets
Six Months Ended June 30, 2006
(in thousands)**

| | |
|---|------------------|
| Total MTM Risk Management Contract Net Assets at December 31, 2005 | \$ 40,894 |
| (Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period | (2,870) |
| Fair Value of New Contracts at Inception When Entered During the Period (a) | 180 |
| Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period | (1,161) |
| Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts | 469 |
| Changes in Fair Value Due to Market Fluctuations During the Period (b) | 6,247 |
| Changes Due to SIA (c) | (4,984) |
| Changes in Fair Value Allocated to Regulated Jurisdictions (d) | 140 |

| | |
|---|------------------|
| Total MTM Risk Management Contract Net Assets | 38,915 |
| Net Cash Flow Hedge Contracts | 11,876 |
| DETM Assignment (e) | (9,094) |
| Total MTM Risk Management Contract Net Assets at June 30, 2006 | \$ 41,697 |

- (a) 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.
- (b) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
- (c) See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 3.
- (d) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.
- (e) See "Natural Gas Contracts with DETM" section of Note 17 of the 2005 Annual Report.

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

The following table presents:

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

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets Fair Value of Contracts as of June 30, 2006 (in thousands)

| | Remainder 2006 | 2007 | 2008 | 2009 | 2010 | After 2010 | Total |
|---|---------------------------|-----------------|-----------------|-----------------|-----------------|-----------------------|------------------|
| Prices Actively Quoted - Exchange Traded Contracts | \$ (2,643) | \$ 2,953 | \$ 3,025 | \$ - | \$ - | \$ - | \$ 3,335 |
| Prices Provided by Other External Sources - OTC Broker Quotes (a) | 7,274 | 7,395 | 3,025 | 5,697 | - | - | 23,391 |
| Prices Based on Models and Other Valuation Methods (b) | 129 | (1,026) | 1,247 | 3,136 | 6,629 | 2,074 | 12,189 |
| Total | \$ 4,760 | \$ 9,322 | \$ 7,297 | \$ 8,833 | \$ 6,629 | \$ 2,074 | \$ 38,915 |

- (a) "Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
- (b) "Prices Based on Models and Other Valuation Methods" is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying

commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

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

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

We employ the use of interest rate derivative transactions to manage interest rate risk related to existing variable rate debt and to manage interest rate exposure on anticipated borrowings of fixed-rate debt. We do not hedge all interest rate risk.

We employ forward contracts as cash flow hedges to lock-in prices on certain transactions which have been denominated in foreign currencies where deemed necessary. We do not hedge all foreign currency exposure.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Condensed Consolidated Balance Sheets and the reasons for the changes from December 31, 2005 to June 30, 2006. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity Six Months Ended June 30, 2006 (in thousands)

| | Power | Foreign Currency | Interest Rate | Total |
|---|----------|---------------------|---------------|-----------|
| Beginning Balance in AOCI December 31, 2005 | \$ (392) | \$ (344) | \$ 1,491 | \$ 755 |
| Changes in Fair Value | 8,405 | - | 2,761 | 11,166 |
| Impact due to Change in SIA (a) | (337) | - | - | (337) |
| Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled | 57 | 7 | (293) | (229) |
| Ending Balance in AOCI June 30, 2006 | \$ 7,733 | \$ (337) | \$ 3,959 | \$ 11,355 |

(a) See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 3.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a \$8,044 thousand gain.

Credit Risk

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

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate

volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at June 30, 2006, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

| Six Months Ended June 30, 2006 (in thousands) | | | | Twelve Months Ended December 31, 2005 (in thousands) | | | |
|--|-------------|----------------|------------|---|-------------|----------------|------------|
| End | High | Average | Low | End | High | Average | Low |
| \$522 | \$1,221 | \$529 | \$306 | \$583 | \$968 | \$461 | \$166 |

VaR Associated with Debt Outstanding

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was \$136 million and \$111 million at June 30, 2006 and December 31, 2005, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

| | Three Months Ended | | Six Months Ended | |
|---|--------------------|----------------|------------------|------------------|
| | 2006 | 2005 | 2006 | 2005 |
| REVENUES | | | | |
| Electric Generation, Transmission and Distribution | \$ 453,064 | \$ 473,991 | \$ 997,703 | \$ 945,001 |
| Sales to AEP Affiliates | 154,648 | 166,227 | 303,907 | 339,953 |
| Other - Affiliated | 3,866 | 3,747 | 7,575 | 7,201 |
| Other - Nonaffiliated | 4,429 | 7,034 | 9,428 | 13,998 |
| TOTAL | 616,007 | 650,999 | 1,318,613 | 1,306,153 |
| EXPENSES | | | | |
| Fuel and Other Consumables for Electric Generation | 211,538 | 222,042 | 446,668 | 449,091 |
| Purchased Electricity for Resale | 26,313 | 22,423 | 48,027 | 41,185 |
| Purchased Electricity from AEP Affiliates | 28,091 | 25,093 | 56,663 | 50,711 |
| Other Operation | 99,196 | 81,279 | 185,833 | 145,849 |
| Maintenance | 71,416 | 52,479 | 118,940 | 98,954 |
| Depreciation and Amortization | 77,848 | 79,941 | 156,661 | 153,888 |
| Taxes Other Than Income Taxes | 48,536 | 43,841 | 95,689 | 91,140 |
| TOTAL | 562,938 | 527,098 | 1,108,481 | 1,030,818 |
| OPERATING INCOME | 53,069 | 123,901 | 210,132 | 275,335 |
| Other Income (Expense): | | | | |
| Interest Income | 595 | 585 | 1,232 | 1,472 |
| Carrying Costs Income | 3,451 | 7,512 | 6,834 | 29,549 |
| Allowance for Equity Funds Used During Construction | 398 | 305 | 1,136 | 732 |
| Interest Expense | (24,437) | (25,839) | (47,851) | (52,002) |
| INCOME BEFORE INCOME TAXES | 33,076 | 106,464 | 171,483 | 255,086 |
| Income Tax Expense | 9,677 | 34,983 | 53,052 | 84,122 |
| NET INCOME | 23,399 | 71,481 | 118,431 | 170,964 |
| Preferred Stock Dividend Requirements including Capital Stock Expense and Other Expense | 183 | 357 | 366 | 540 |
| | \$ 23,216 | \$ 71,124 | \$ 118,065 | \$ 170,424 |

**EARNINGS APPLICABLE TO
COMMON STOCK**

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

| | Common Stock | Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total |
|--|-----------------|--------------------|----------------------|---|--------------|
| DECEMBER 31, 2004 | \$ 321,201 | \$ 462,485 | \$ 764,416 | \$ (74,264) | \$ 1,473,838 |
| Common Stock Dividends | | | (14,999) | | (14,999) |
| Preferred Stock Dividends | | | (366) | | (366) |
| Other | | 4,151 | (174) | | 3,977 |
| TOTAL | | | | | 1,462,450 |
| COMPREHENSIVE INCOME | | | | | |
| Other Comprehensive Loss, Net of Taxes: | | | | | |
| Cash Flow Hedges, Net of Tax of \$3,823 | | | | (7,099) | (7,099) |
| NET INCOME | | | 170,964 | | 170,964 |
| TOTAL COMPREHENSIVE INCOME | | | | | 163,865 |
| JUNE 30, 2005 | \$ 321,201 | \$ 466,636 | \$ 919,841 | \$ (81,363) | \$ 1,626,315 |
| DECEMBER 31, 2005 | \$ 321,201 | \$ 466,637 | \$ 979,354 | \$ 755 | \$ 1,767,947 |
| Capital Contribution From Parent | | 70,000 | | | 70,000 |
| Preferred Stock Dividends | | | (366) | | (366) |
| Gain on Reacquired Preferred Stock | | 2 | | | 2 |
| TOTAL | | | | | 1,837,583 |
| COMPREHENSIVE INCOME | | | | | |
| Other Comprehensive Income, Net of Taxes: | | | | | |
| Cash Flow Hedges, Net of Tax of \$5,708 | | | | 10,600 | 10,600 |
| NET INCOME | | | 118,431 | | 118,431 |
| TOTAL COMPREHENSIVE INCOME | | | | | 129,031 |
| JUNE 30, 2006 | \$ 321,201 | \$ 536,639 | \$ 1,097,419 | \$ 11,355 | \$ 1,966,614 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

**OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS**

ASSETS

June 30, 2006 and December 31, 2005

(in thousands)

(Unaudited)

| | 2006 | 2005 |
|---|---------------------|---------------------|
| CURRENT ASSETS | | |
| Cash and Cash Equivalents | \$ 990 | \$ 1,240 |
| Advances to Affiliates | 36,787 | - |
| Accounts Receivable: | | |
| Customers | 111,742 | 125,404 |
| Affiliated Companies | 98,590 | 167,579 |
| Accrued Unbilled Revenues | 12,749 | 14,817 |
| Miscellaneous | 3,665 | 15,644 |
| Allowance for Uncollectible Accounts | (2,651) | (1,517) |
| Total Accounts Receivable | 224,095 | 321,927 |
| Fuel | 148,342 | 97,600 |
| Materials and Supplies | 66,270 | 60,937 |
| Emission Allowances | 22,308 | 39,251 |
| Risk Management Assets | 72,566 | 115,020 |
| Accrued Tax Benefits | 1,863 | 39,965 |
| Margin Deposits | 1,488 | 23,053 |
| Prepayments and Other | 8,697 | 4,386 |
| TOTAL | 583,406 | 703,379 |
| PROPERTY, PLANT AND EQUIPMENT | | |
| Electric: | | |
| Production | 4,341,360 | 4,278,553 |
| Transmission | 1,007,723 | 1,002,255 |
| Distribution | 1,296,690 | 1,258,518 |
| Other | 295,114 | 293,794 |
| Construction Work in Progress | 999,227 | 690,168 |
| Total | 7,940,114 | 7,523,288 |
| Accumulated Depreciation and Amortization | 2,776,072 | 2,738,899 |
| TOTAL - NET | 5,164,042 | 4,784,389 |
| OTHER NONCURRENT ASSETS | | |
| Regulatory Assets | 364,411 | 398,007 |
| Long-term Risk Management Assets | 98,547 | 144,015 |
| Deferred Charges and Other | 263,959 | 300,880 |
| TOTAL | 726,917 | 842,902 |
| TOTAL ASSETS | \$ 6,474,365 | \$ 6,330,670 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

**OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
June 30, 2006 and December 31, 2005
(Unaudited)**

| | 2006 | 2005 |
|--|---------------------|---------------------|
| CURRENT LIABILITIES | (in thousands) | |
| Advances from Affiliates | \$ - | \$ 70,071 |
| Accounts Payable: | | |
| General | 228,869 | 210,752 |
| Affiliated Companies | 109,016 | 147,470 |
| Short-term Debt - Nonaffiliated | 5,272 | 10,366 |
| Long-term Debt Due Within One Year - Affiliated | - | 200,000 |
| Long-term Debt Due Within One Year - Nonaffiliated | 12,354 | 12,354 |
| Risk Management Liabilities | 52,055 | 108,797 |
| Customer Deposits | 29,857 | 51,209 |
| Accrued Taxes | 113,439 | 158,774 |
| Accrued Interest | 38,969 | 36,298 |
| Other | 106,345 | 111,480 |
| TOTAL | 696,176 | 1,117,571 |
| NONCURRENT LIABILITIES | | |
| Long-term Debt - Nonaffiliated | 2,190,481 | 1,787,316 |
| Long-term Debt - Affiliated | 200,000 | 200,000 |
| Long-term Risk Management Liabilities | 77,361 | 119,247 |
| Deferred Income Taxes | 986,010 | 987,386 |
| Regulatory Liabilities and Deferred Investment Tax Credits | 176,868 | 168,492 |
| Deferred Credits and Other | 146,830 | 154,770 |
| TOTAL | 3,777,550 | 3,417,211 |
| TOTAL LIABILITIES | 4,473,726 | 4,534,782 |
| Minority Interest | 17,394 | 11,302 |
| Cumulative Preferred Stock Not Subject to Mandatory Redemption | 16,631 | 16,639 |
| Commitments and Contingencies (Note 5) | | |
| COMMON SHAREHOLDER'S EQUITY | | |
| Common Stock - No Par Value Per Share: | | |
| Authorized - 40,000,000 Shares | | |
| Outstanding - 27,952,473 Shares | 321,201 | 321,201 |
| Paid-in Capital | 536,639 | 466,637 |
| Retained Earnings | 1,097,419 | 979,354 |
| Accumulated Other Comprehensive Income | 11,355 | 755 |
| TOTAL | 1,966,614 | 1,767,947 |
| TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY | \$ 6,474,365 | \$ 6,330,670 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

| | 2006 | 2005 |
|--|------------------|------------------|
| OPERATING ACTIVITIES | | |
| Net Income | \$ 118,431 | \$ 170,964 |
| Adjustments for Noncash Items: | | |
| Depreciation and Amortization | 156,661 | 153,888 |
| Deferred Income Taxes | (8,073) | 9,923 |
| Carrying Costs Income | (6,834) | (29,549) |
| Mark-to-Market of Risk Management Contracts | 1,263 | (2,271) |
| Pension Contributions to Qualified Plan Trusts | - | (40,013) |
| Deferred Property Taxes | 35,550 | 32,254 |
| Change in Other Noncurrent Assets | 9,323 | (17,618) |
| Change in Other Noncurrent Liabilities | 16,355 | 3,462 |
| Changes in Components of Working Capital: | | |
| Accounts Receivable, Net | 97,832 | (6,457) |
| Fuel, Materials and Supplies | (56,075) | (44,097) |
| Accounts Payable | (42,878) | (35,434) |
| Accrued Taxes, Net | (7,233) | (93,300) |
| Other Current Assets | 35,848 | 53,872 |
| Other Current Liabilities | (23,816) | 23,931 |
| Net Cash Flows From Operating Activities | 326,354 | 179,555 |
| INVESTING ACTIVITIES | | |
| Construction Expenditures | (481,541) | (288,921) |
| Change in Advances to Affiliates, Net | (36,787) | 125,971 |
| Other | 1,450 | 7,299 |
| Net Cash Flows Used For Investing Activities | (516,878) | (155,651) |
| FINANCING ACTIVITIES | | |
| Capital Contributions from Parent Company | 70,000 | - |
| Issuance of Long-term Debt - Nonaffiliated | 405,839 | 214,120 |
| Change in Short-term Debt, Net - Nonaffiliated | (5,094) | (9,146) |
| Change in Advances from Affiliates, Net | (70,071) | 11,528 |
| Retirement of Long-term Debt - Nonaffiliated | (6,177) | (224,177) |
| Retirement of Long-term Debt - Affiliated | (200,000) | - |
| Retirement of Preferred Stock | (8) | (5,000) |
| Principal Payments for Capital Lease Obligations | (3,849) | (3,847) |
| Dividends Paid on Common Stock | - | (14,999) |
| Dividends Paid on Cumulative Preferred Stock | (366) | (366) |
| Net Cash Flows From (Used For) Financing Activities | 190,274 | (31,887) |
| Net Decrease in Cash and Cash Equivalents | (250) | (7,983) |
| Cash and Cash Equivalents at Beginning of Period | 1,240 | 9,337 |
| Cash and Cash Equivalents at End of Period | \$ 990 | \$ 1,354 |

| SUPPLEMENTARY INFORMATION | | | |
|--|----|--------|-----------|
| Cash Paid for Interest, Net of Capitalized Amounts | \$ | 43,794 | \$ 52,403 |
| Cash Paid for Income Taxes, Net of Refunds | | 24,077 | 114,782 |
| Noncash Acquisitions Under Capital Leases | | 1,662 | 7,210 |
| Construction Expenditures Included in Accounts Payable at June 30, | | 97,389 | 51,850 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

**OHIO POWER COMPANY CONSOLIDATED
INDEX TO CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT
SUBSIDIARIES**

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

| | Footnote Reference |
|--|-------------------------------|
| Significant Accounting Matters | Note 1 |
| New Accounting Pronouncements | Note 2 |
| Rate Matters | Note 3 |
| Customer Choice and Industry Restructuring | Note 4 |
| Commitments and Contingencies | Note 5 |
| Guarantees | Note 6 |
| Company-wide Staffing and Budget Review | Note 7 |
| Benefit Plans | Note 9 |
| Business Segments | Note 11 |
| Financing Activities | Note 12 |

PUBLIC SERVICE COMPANY OF OKLAHOMA

PUBLIC SERVICE COMPANY OF OKLAHOMA
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

Allocation Agreement between AEP East companies and AEP West companies

The SIA provides, among other things, for the methodology of sharing trading and marketing margins between the AEP East companies and AEP West companies. In March 2006, the FERC approved AEP's proposed methodology to be used effective April 1, 2006 and beyond. The approved allocation methodology is based upon the location of the specific trading and marketing activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to the benefit of SWEPCo and us. Previously, the SIA allocation provided for a different method of sharing all such margins between both AEP East companies and AEP West companies. The impact on future results of operations, financial condition and cash flows will depend upon the level of future margins and risk management activity by region.

Results of Operations

Second Quarter of 2006 Compared to Second Quarter of 2005

Reconciliation of Second Quarter of 2005 to Second Quarter of 2006 Net Income
(in millions)

| | | |
|---|------|------|
| Second Quarter of 2005 | \$ | 19 |
| Changes in Gross Margin: | | |
| Retail and Off-system Sales Margins | 11 | |
| Other | 1 | |
| Total Change in Gross Margin | | 12 |
| Changes in Operating Expenses and Other: | | |
| Other Operation and Maintenance | (11) | |
| Taxes Other Than Income Taxes | (4) | |
| Interest Expense | (1) | |
| Total Change in Operating Expenses and Other | | (16) |
| Second Quarter of 2006 | \$ | 15 |

Net Income decreased \$4 million in the second quarter of 2006. The key driver of the decrease was a \$16 million increase in Operating Expenses and Other, partially offset by a \$12 million increase in Gross Margin.

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

- Retail and Off-system Sales Margins increased \$11 million primarily due to higher retail margins from an increase in sales volumes, partially offset by decreased off-system sales margins due to lower optimization activities and a reduction in physical off-system sales under the SIA.

Operating Expenses and Other increased between years as follows:

- Other Operation and Maintenance expenses increased \$11 million due to a \$7 million increase in scheduled overhead line maintenance and a \$3 million increase primarily due to slightly higher power plant operations and factoring of accounts receivable.
- Taxes Other Than Income Taxes increased \$4 million primarily due to the absence of a 2004 adjustment for property-related taxes recorded in 2005.

Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2005

**Reconciliation of Six Months Ended June 30, 2005 to Six Months Ended June 30, 2006 Net Income
(in millions)**

| | | |
|---|------|------|
| Six Months Ended June 30, 2005 | \$ | 19 |
| Changes in Gross Margin: | | |
| Retail and Off-system Sales Margins | 14 | |
| Transmission Revenues | 1 | |
| Other | 3 | |
| Total Change in Gross Margin | | 18 |
| Changes in Operating Expenses and Other: | | |
| Other Operation and Maintenance | (27) | |
| Depreciation and Amortization | 2 | |
| Taxes Other Than Income Taxes | (4) | |
| Interest Expense | (2) | |
| Total Change in Operating Expenses and Other | | (31) |
| Income Tax Expense | | 3 |
| Six Months Ended June 30, 2006 | \$ | 9 |

Net Income decreased \$10 million for the six months ended June 30, 2006 compared with the six months ended June 30, 2005. The key driver of the decrease was a \$27 million increase in Other Operation and Maintenance expenses, partially offset by an \$18 million increase in Gross Margin.

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

- Retail and Off-system Sales Margins increased \$14 million primarily due to higher retail margins from an increase in sales volumes, partially offset by decreased off-system sales margins due to lower optimization activities and a reduction in physical off-system sales under the SIA.
- Other increased \$3 million primarily due to a 2006 settlement received from an electric cooperative.

Operating Expenses and Other increased between years as follows:

- Other Operation and Maintenance expenses increased \$27 million due to a \$6 million increase in forced and scheduled power plant maintenance, a \$10 million increase in scheduled overhead line maintenance and a \$10 million increase primarily due to higher

power plant operations, customer-related expenses, factoring of accounts receivable and outside services.

- Depreciation and Amortization decreased \$2 million primarily due to a change in depreciation rates implemented in June 2005, resulting from the settlement of our 2005 rate review proceedings.
- Taxes Other Than Income Taxes increased \$4 million primarily due to the absence of a 2004 adjustment for property-related taxes recorded in 2005.
- Interest Expense increased \$2 million primarily due to increased affiliated short-term borrowings.

Income Taxes

The \$3 million decrease in Income Tax Expense is primarily due to the decrease in pretax book income and state income taxes, offset in part by tax reserve adjustments.

Financial Condition

Credit Ratings

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

| | Moody's | S&P | Fitch |
|-----------------------|----------------|----------------|--------------|
| Senior Unsecured Debt | Baa1 | BBB | A- |

Financing Activity

Long-term debt retirements and principal payments during the first six months of 2006 were:

| Type of Debt | Principal Amount (in thousands) | Interest Rate (%) | Due Date |
|-------------------------------|--|------------------------------|-----------------|
| Notes Payable - Affiliated | \$ 50,000 | 3.35 | 2006 |

Liquidity

We have solid investment grade ratings, which provide us ready access to capital markets in order to issue new debt or refinance long-term debt maturities. In addition, we participate in the Utility Money Pool, which provides access to AEP's liquidity.

Summary Obligation Information

A summary of our contractual obligations is included in our 2005 Annual Report and has not changed significantly from year-end except for Energy and Capacity Purchase Contracts. We increased our future obligation in Energy and Capacity Purchase Contracts applicable to our optimization and off-system sales activities by approximately \$75 million annually due to changes within the SIA and CSW Operating Agreement. See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section within Note 3 - Rate Matters.

Significant Factors

Litigation and Regulatory Activity

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our pending litigation and regulatory proceedings, see Note 4 - Rate Matters and Note 7 - Commitments and Contingencies in our 2005 Annual Report. Also, see Note 3 - Rate Matters and Note 5 - Commitments and Contingencies in the "Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries" section. An adverse result in these proceedings has the potential to materially affect our results of operations, financial condition and cash flows.

New Generation

In December 2005, we sought proposals for new base load generation to be online in 2011. We received six proposals and evaluated those proposals meeting the Request for Proposal criteria with oversight from a neutral third-party. In July 2006, we announced plans to enter a joint venture with Oklahoma Gas and Electric Company (OG&E) where OG&E will construct and operate a new 950 MW coal-fueled electricity generating unit near Red Rock, Oklahoma. We will own 50% of the new unit. Preliminary cost estimates for 100% of the new facility are approximately \$1.8 billion. The 2006 through 2008 estimated construction expenditures as disclosed in our 2005 Form 10-K included cost estimates for a base load facility. This new facility is subject to regulatory approval from the OCC. Construction is expected to begin in 2007.

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

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2005 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, pension benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES**Market Risks**

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

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our condensed balance sheet as of June 30, 2006 and the reasons for changes in our total MTM value as compared to December 31, 2005.

**Reconciliation of MTM Risk Management Contracts to
Condensed Balance Sheet
As of June 30, 2006
(in thousands)**

| | MTM Risk Management Contracts | Cash Flow Hedges | Total |
|--|-------------------------------------|---------------------|------------------|
| Current Assets | \$ 71,817 | \$ - | \$ 71,817 |
| Noncurrent Assets | 40,199 | - | 40,199 |
| Total MTM Derivative Contract Assets | 112,016 | - | 112,016 |
| Current Liabilities | (55,332) | - | (55,332) |
| Noncurrent Liabilities | (30,491) | - | (30,491) |
| Total MTM Derivative Contract Liabilities | (85,823) | - | (85,823) |
| Total MTM Derivative Contract Net Assets | \$ 26,193 | \$ - | \$ 26,193 |

**MTM Risk Management Contract Net Assets
Six Months Ended June 30, 2006
(in thousands)**

| | |
|---|------------------|
| Total MTM Risk Management Contract Net Assets at December 31, 2005 | \$ 14,214 |
| (Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period | 140 |
| Fair Value of New Contracts at Inception When Entered During the Period (a) | - |
| Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period | 7,621 |
| Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts | - |
| Changes in Fair Value Due to Market Fluctuations During the Period (b) | (162) |
| Changes Due to SIA and CSW Operating Agreement (c) | 10,185 |
| Changes in Fair Value Allocated to Regulated Jurisdictions (d) | (5,805) |
| Total MTM Risk Management Contract Net Assets | 26,193 |
| Net Cash Flow Hedge Contracts | - |
| Total MTM Risk Management Contract Net Assets at June 30, 2006 | \$ 26,193 |

(a)

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.

- (b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
- (c) See “Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement” section of Note 3.
- (d) “Changes in Fair Value Allocated to Regulated Jurisdictions” relates to the net gains (losses) of those contracts that are not reflected in the Condensed Statements of Operations. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

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

The following table presents:

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

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets Fair Value of Contracts as of June 30, 2006 (in thousands)

| | Remainder | | | | | After | | |
|---|------------------|-----------------|-----------------|---------------|---------------|---------------|------------------|--|
| | 2006 | 2007 | 2008 | 2009 | 2010 | 2010 | Total | |
| Prices Actively Quoted - Exchange Traded Contracts | \$ (880) | \$ (1,879) | \$ 595 | \$ (123) | \$ - | \$ - | \$ (2,287) | |
| Prices Provided by Other External Sources - OTC Broker Quotes (a) | 5,961 | 6,348 | 9,343 | 398 | - | - | 22,050 | |
| Prices Based on Models and Other Valuation Methods (b) | 9,081 | (676) | (1,945) | (26) | (3) | (1) | 6,430 | |
| Total | \$ 14,162 | \$ 3,793 | \$ 7,993 | \$ 249 | \$ (3) | \$ (1) | \$ 26,193 | |

(a) “Prices Provided by Other External Sources - OTC Broker Quotes” reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.

(b) “Prices Based on Models and Other Valuation Methods” is used in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.

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

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

We employ the use of interest rate derivative transactions to manage interest rate risk related to existing variable rate debt and to manage interest rate exposure on anticipated borrowings of fixed-rate debt. We do not hedge all interest rate risk.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Condensed Balance Sheets and the reasons for the changes from December 31, 2005 to June 30, 2006. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Six Months Ended June 30, 2006
(in thousands)

| | Power | Interest Rate | Total |
|--|----------|---------------|------------|
| Beginning Balance in AOCI December 31, 2005 | \$ (629) | \$ (483) | \$ (1,112) |
| Changes in Fair Value | 12 | - | 12 |
| Impact Due to Change in SIA (a) | 506 | - | 506 |
| Reclassifications from AOCI to Net Income for Cash | | | |
| Flow Hedges Settled | 123 | 55 | 178 |
| Ending Balance in AOCI June 30, 2006 | \$ 12 | \$ (428) | \$ (416) |

(a) See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 3.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a \$98 thousand loss.

Credit Risk

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

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at June 30, 2006, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

| | Six Months Ended June 30, 2006 (in thousands) | | | | Twelve Months Ended December 31, 2005 (in thousands) | | |
|-------|---|---------|------|-------|--|---------|------|
| | High | Average | Low | | High | Average | Low |
| End | | | | End | | | |
| \$603 | \$1,432 | \$546 | \$58 | \$311 | \$517 | \$246 | \$89 |

VaR Associated with Debt Outstanding

We also utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was \$33 million and \$34 million at June 30, 2006 and December 31, 2005, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or financial position.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

| | Three Months Ended | | Six Months Ended | |
|--|--------------------|------------------|------------------|------------------|
| | 2006 | 2005 | 2006 | 2005 |
| REVENUES | | | | |
| Electric Generation, Transmission and Distribution | \$ 333,313 | \$ 272,329 | \$ 672,914 | \$ 522,427 |
| Sales to AEP Affiliates | 12,545 | 13,650 | 26,613 | 16,282 |
| Other | 1,188 | 623 | 2,248 | 975 |
| TOTAL | 347,046 | 286,602 | 701,775 | 539,684 |
| EXPENSES | | | | |
| Fuel and Other Consumables for Electric Generation | 150,976 | 129,544 | 364,149 | 263,722 |
| Purchased Electricity for Resale | 56,358 | 30,132 | 89,575 | 44,925 |
| Purchased Electricity from AEP Affiliates | 15,880 | 15,389 | 37,111 | 38,234 |
| Other Operation | 40,098 | 36,641 | 76,965 | 67,139 |
| Maintenance | 22,033 | 14,153 | 42,340 | 25,512 |
| Depreciation and Amortization | 21,600 | 22,247 | 42,621 | 44,866 |
| Taxes Other Than Income Taxes | 10,077 | 6,061 | 20,153 | 15,738 |
| TOTAL | 317,022 | 254,167 | 672,914 | 500,136 |
| OPERATING INCOME | 30,024 | 32,435 | 28,861 | 39,548 |
| Other Income | 211 | 242 | 780 | 407 |
| Interest Expense | (9,634) | (8,621) | (18,769) | (16,496) |
| INCOME BEFORE INCOME TAXES | 20,601 | 24,056 | 10,872 | 23,459 |
| Income Tax Expense | 5,963 | 5,486 | 1,591 | 4,384 |
| NET INCOME | 14,638 | 18,570 | 9,281 | 19,075 |
| Preferred Stock Dividend Requirements | 53 | 53 | 106 | 106 |
| EARNINGS APPLICABLE TO COMMON STOCK | \$ 14,585 | \$ 18,517 | \$ 9,175 | \$ 18,969 |

The common stock of PSO is owned by a wholly-owned subsidiary of AEP.

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

| | Common Stock | Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total |
|--|-----------------|--------------------|----------------------|---|----------------|
| DECEMBER 31, 2004 | \$ 157,230 | \$ 230,016 | \$ 141,935 | \$ 75 | \$ 529,256 |
| Common Stock Dividends | | | (17,000) | | (17,000) |
| Preferred Stock Dividends | | | (106) | | (106) |
| TOTAL | | | | | 512,150 |
| COMPREHENSIVE INCOME | | | | | |
| Other Comprehensive Loss, Net of Taxes: | | | | | |
| Cash Flow Hedges, Net of Tax of \$798 | | | | (1,483) | (1,483) |
| NET INCOME | | | 19,075 | | 19,075 |
| TOTAL COMPREHENSIVE INCOME | | | | | 17,592 |
| JUNE 30, 2005 | \$ 157,230 | \$ 230,016 | \$ 143,904 | \$ (1,408) | \$ 529,742 |
| DECEMBER 31, 2005 | \$ 157,230 | \$ 230,016 | \$ 162,615 | \$ (1,264) | \$ 548,597 |
| Preferred Stock Dividends | | | (106) | | (106) |
| TOTAL | | | | | 548,491 |
| COMPREHENSIVE INCOME | | | | | |
| Other Comprehensive Income, Net of Taxes: | | | | | |
| Cash Flow Hedges, Net of Tax of \$375 | | | | 696 | 696 |
| NET INCOME | | | 9,281 | | 9,281 |
| TOTAL COMPREHENSIVE INCOME | | | | | 9,977 |
| JUNE 30, 2006 | \$ 157,230 | \$ 230,016 | \$ 171,790 | \$ (568) | \$ 558,468 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

**PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS**

ASSETS

June 30, 2006 and December 31, 2005

(in thousands)

(Unaudited)

| | 2006 | 2005 |
|---|---------------------|---------------------|
| CURRENT ASSETS | | |
| Cash and Cash Equivalents | \$ 2,001 | \$ 1,520 |
| Accounts Receivable: | | |
| Customers | 58,481 | 37,740 |
| Affiliated Companies | 45,649 | 73,321 |
| Miscellaneous | 9,360 | 10,501 |
| Allowance for Uncollectible Accounts | (248) | (240) |
| Total Accounts Receivable | 113,242 | 121,322 |
| Fuel | 18,157 | 16,431 |
| Materials and Supplies | 43,635 | 38,545 |
| Risk Management Assets | 71,817 | 40,383 |
| Accrued Tax Benefits | - | 11,972 |
| Regulatory Asset for Under-Recovered Fuel Costs | 33,635 | 108,732 |
| Margin Deposits | 56,968 | 10,051 |
| Prepayments and Other | 2,575 | 4,236 |
| TOTAL | 342,030 | 353,192 |
| PROPERTY, PLANT AND EQUIPMENT | | |
| Electric: | | |
| Production | 1,082,122 | 1,072,928 |
| Transmission | 490,629 | 479,272 |
| Distribution | 1,181,226 | 1,140,535 |
| Other | 235,026 | 211,805 |
| Construction Work in Progress | 71,305 | 90,455 |
| Total | 3,060,308 | 2,994,995 |
| Accumulated Depreciation and Amortization | 1,185,635 | 1,175,858 |
| TOTAL - NET | 1,874,673 | 1,819,137 |
| OTHER NONCURRENT ASSETS | | |
| Regulatory Assets | 85,178 | 50,723 |
| Long-term Risk Management Assets | 40,199 | 33,566 |
| Employee Benefits and Pension Assets | 80,654 | 82,559 |
| Deferred Charges and Other | 34,035 | 16,287 |
| TOTAL | 240,066 | 183,135 |
| TOTAL ASSETS | \$ 2,456,769 | \$ 2,355,464 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
June 30, 2006 and December 31, 2005
(Unaudited)

| | 2006 | 2005 |
|--|---------------------|---------------------|
| | (in thousands) | |
| CURRENT LIABILITIES | | |
| Advances from Affiliates | \$ 139,831 | \$ 75,883 |
| Accounts Payable: | | |
| General | 135,395 | 130,627 |
| Affiliated Companies | 110,983 | 89,786 |
| Long-term Debt Due Within One Year - Affiliated | - | 50,000 |
| Risk Management Liabilities | 55,332 | 38,243 |
| Customer Deposits | 55,339 | 53,844 |
| Accrued Taxes | 44,424 | 22,420 |
| Other | 32,327 | 51,548 |
| TOTAL | 573,631 | 512,351 |
| NONCURRENT LIABILITIES | | |
| Long-term Debt - Nonaffiliated | 521,101 | 521,071 |
| Long-term Risk Management Liabilities | 30,491 | 22,582 |
| Deferred Income Taxes | 415,090 | 436,382 |
| Regulatory Liabilities and Deferred Investment Tax Credits | 327,532 | 284,640 |
| Deferred Credits and Other | 25,194 | 24,579 |
| TOTAL | 1,319,408 | 1,289,254 |
| TOTAL LIABILITIES | 1,893,039 | 1,801,605 |
| Cumulative Preferred Stock Not Subject to Mandatory Redemption | 5,262 | 5,262 |
| Commitments and Contingencies (Note 5) | | |
| COMMON SHAREHOLDER'S EQUITY | | |
| Common Stock - \$15 Par Value Per Share: | | |
| Authorized - 11,000,000 Shares | | |
| Issued - 10,482,000 Shares | | |
| Outstanding - 9,013,000 Shares | 157,230 | 157,230 |
| Paid-in Capital | 230,016 | 230,016 |
| Retained Earnings | 171,790 | 162,615 |
| Accumulated Other Comprehensive Income (Loss) | (568) | (1,264) |
| TOTAL | 558,468 | 548,597 |
| TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY | \$ 2,456,769 | \$ 2,355,464 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

| | 2006 | 2005 |
|--|-----------------|-----------------|
| OPERATING ACTIVITIES | | |
| Net Income | \$ 9,281 | \$ 19,075 |
| Adjustments for Noncash Items: | | |
| Depreciation and Amortization | 42,621 | 44,866 |
| Deferred Income Taxes | (22,319) | 2,998 |
| Mark-to-Market of Risk Management Contracts | (11,979) | 10,934 |
| Deferred Property Taxes | (16,196) | (16,245) |
| Change in Other Noncurrent Assets | 9,665 | (18,943) |
| Change in Other Noncurrent Liabilities | (8,232) | (2,529) |
| Changes in Components of Working Capital: | | |
| Accounts Receivable, Net | 8,080 | 19,705 |
| Fuel, Materials and Supplies | (6,816) | (6,755) |
| Accounts Payable | 28,517 | 52,198 |
| Accrued Taxes, Net | 33,976 | 11,161 |
| Over/Under Fuel Recovery | 75,097 | 1,551 |
| Margin Deposits | (46,917) | 1,753 |
| Other Current Assets | 1,655 | 535 |
| Other Current Liabilities | (17,726) | (9,008) |
| Net Cash Flows From Operating Activities | 78,707 | 111,296 |
| INVESTING ACTIVITIES | | |
| Construction Expenditures | (91,617) | (55,697) |
| Change in Other Cash Deposits, Net | 6 | (6) |
| Change in Advances to Affiliates, Net | - | (7,084) |
| Net Cash Flows Used For Investing Activities | (91,611) | (62,787) |
| FINANCING ACTIVITIES | | |
| Issuance of Long-term Debt - Nonaffiliated | - | 74,408 |
| Retirement of Long-term Debt - Nonaffiliated | - | (50,000) |
| Retirement of Long-term Debt - Affiliated | (50,000) | - |
| Change in Advances from Affiliates, Net | 63,948 | (55,002) |
| Principal Payments for Capital Lease Obligations | (457) | (310) |
| Dividends Paid on Common Stock | - | (17,000) |
| Dividends Paid on Cumulative Preferred Stock | (106) | (106) |
| Net Cash Flows From (Used For) Financing Activities | 13,385 | (48,010) |
| Net Increase in Cash and Cash Equivalents | 481 | 499 |
| Cash and Cash Equivalents at Beginning of Period | 1,520 | 279 |
| Cash and Cash Equivalents at End of Period | \$ 2,001 | \$ 778 |
| SUPPLEMENTARY INFORMATION | | |
| Cash Paid for Interest, Net of Capitalized Amounts | \$ 17,461 | \$ 15,028 |

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| | | |
|--|-------|-------|
| Cash Paid for Income Taxes, Net of Refunds | 5,656 | 3,590 |
| Noncash Acquisitions Under Capital Leases | 1,780 | 738 |
| Construction Expenditures Included in Accounts Payable at June 30, | 5,943 | 1,635 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA
INDEX TO CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT
SUBSIDIARIES

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

| | Footnote Reference |
|---|-------------------------------|
| Significant Accounting Matters | Note 1 |
| New Accounting Pronouncements | Note 2 |
| Rate Matters | Note 3 |
| Commitments and Contingencies | Note 5 |
| Guarantees | Note 6 |
| Company-wide Staffing and Budget Review | Note 7 |
| Benefit Plans | Note 9 |
| Income Taxes | Note 10 |
| Business Segments | Note 11 |
| Financing Activities | Note 12 |

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

**SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS**

Allocation Agreement between AEP East companies and AEP West companies

The SIA provides, among other things, for the methodology of sharing trading and marketing margins between the AEP East companies and AEP West companies. In March 2006, the FERC approved AEP's proposed methodology to be used effective April 1, 2006 and beyond. The approved allocation methodology is based upon the location of the specific trading and marketing activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to the benefit of PSO and us. Previously, the SIA allocation provided for a different method of sharing all such margins between both AEP East companies and AEP West companies. The impact on future results of operations, financial condition and cash flows will depend upon the level of future margins and risk management activities by region and the status of cost recovery mechanisms by state.

Results of Operations

Second Quarter of 2006 Compared to Second Quarter of 2005

**Reconciliation of Second Quarter of 2005 to Second Quarter of 2006 Net Income
(in millions)**

| | | |
|---|-----|-----|
| Second Quarter of 2005 | \$ | 19 |
| Changes in Gross Margin: | | |
| Retail and Off-system Sales Margins (a) | 9 | |
| Transmission Revenues | 2 | |
| Other | 7 | |
| Total Change in Gross Margin | | 18 |
| Changes in Operating Expenses and Other: | | |
| Other Operation and Maintenance | (1) | |
| Interest Expense | (1) | |
| Total Change in Operating Expenses and Other | | (2) |
| Income Tax Expense | | (7) |
| Second Quarter of 2006 | \$ | 28 |

(a)Includes firm wholesale sales to municipals and cooperatives.

Net Income increased \$9 million to \$28 million in the second quarter of 2006. The key driver of the increase was an \$18 million increase in Gross Margin, partially offset by a \$7 million increase in Income Tax Expense.

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

- Retail and Off-system Sales Margins increased \$9 million due to an increase in wholesale margins resulting from higher prices, partially offset by decreased off-system sales margins due to lower optimization activities and a reduction in physical off-system sales under the SIA.
- Transmission Revenues increased \$2 million primarily due to higher rates within SPP.
- Other revenues increased \$7 million primarily due to gains on sales of emission allowances.

Income Taxes

The \$7 million increase in Income Tax Expense is primarily due to the increase in pretax book income.

Six Months Ended June 30, 2006 Compared to Six Ended June 30, 2005

**Reconciliation of Six Months Ended June 30, 2005 to Six Months Ended June 30, 2006 Net Income
(in millions)**

| | | |
|---|-----------|-------------|
| Six Months Ended June 30, 2005 | \$ | 32 |
| Changes in Gross Margin: | | |
| Retail and Off-system Sales Margins (a) | 25 | |
| Transmission Revenues | 2 | |
| Other | 15 | |
| Total Change in Gross Margin | | 42 |
| Changes in Operating Expenses and Other: | | |
| Other Operation and Maintenance | (15) | |
| Interest Expense | (1) | |
| Total Change in Operating Expenses and Other | | (16) |
| Income Tax Expense | | (12) |
| Six Months Ended June 30, 2006 | \$ | 46 |

(a)Includes firm wholesale sales to municipals and cooperatives.

Net Income increased \$14 million to \$46 million for the six months ended June 30, 2006. The key driver of the increase was a \$42 million increase in Gross Margin, offset by a \$15 million increase in Other Operation and Maintenance expenses and a \$12 million increase in Income Tax Expense.

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

- Retail and Off-system Sales Margins increased \$25 million primarily due to an increase in wholesale margins resulting from higher prices, partially offset by decreased off-system sales margins due to lower optimization activities and a reduction in physical off-system sales under the SIA.
- Transmission Revenues increased \$2 million primarily due to higher rates within SPP.
- Other revenues increased \$15 million primarily due to gains on sales of emission allowances.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expenses increased \$15 million primarily due to an \$11 million increase in power production and higher administrative and general expenses and a \$4 million increase in maintenance performed at power plants during scheduled outages.

Income Taxes

The \$12 million increase in Income Tax Expense is primarily due to the increase in pretax book income and state income taxes.

Financial Condition

Credit Ratings

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

| | Moody's | S&P | Fitch |
|-----------------------|----------------|----------------|--------------|
| First Mortgage Bonds | A3 | A- | A |
| Senior Unsecured Debt | Baa1 | BBB | A- |

Cash Flow

Cash flows for the six months ended June 30, 2006 and 2005 were as follows:

| | 2006 | 2005 |
|---|-----------------------|-------------|
| | (in thousands) | |
| Cash and Cash Equivalents at Beginning of Period | \$ 3,049 | \$ 3,715 |
| Net Cash Flows From (Used For): | | |
| Operating Activities | 76,154 | 99,285 |
| Investing Activities | (123,275) | (216,468) |
| Financing Activities | 46,180 | 118,059 |
| Net Increase (Decrease) in Cash and Cash Equivalents | (941) | 876 |
| Cash and Cash Equivalents at End of Period | \$ 2,108 | \$ 4,591 |

Operating Activities

Net Cash Flows From Operating Activities were \$76 million in 2006. We produced Net Income of \$46 million during the period and noncash expense items of \$65 million for Depreciation and Amortization. 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 working capital relates to a number of items. The \$60 million inflow from Accounts Payable was the result of higher energy purchases. The \$53 million outflow from Margin Deposits was due to increased trading-related deposits resulting from the amended SIA. In addition, our \$37 million inflow related to Over/Under Fuel Recovery was primarily due to the new fuel surcharges effective December 2005 in our Arkansas service territory and in January 2006 in our Texas service territory. The \$23 million outflow from Fuel, Materials and Supplies was the result of increased fuel purchases.

Net Cash Flows From Operating Activities were \$99 million in 2005. We produced Net Income of \$32 million during the period and noncash expense items of \$66 million for Depreciation and Amortization. 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 \$28 million inflow from Accounts Payable was due to higher vendor-related payables and increased energy transactions. The \$25 million outflow related to Over/Under Fuel Recovery was due to our increasing cumulative under-recovery of rising fuel costs.

Investing Activities

Cash Flows Used For Investing Activities during 2006 and 2005 were \$123 million and \$216 million, respectively. The cash flows during 2006 were comprised primarily of Construction Expenditures related to projects for improved transmission and distribution service reliability. For the remainder of 2006, we expect \$200 million in Construction Expenditures. During 2005, Construction Expenditures were \$72 million, also comprised primarily of spending for transmission and distribution service reliability. Additionally, we increased our Advances to Affiliates by \$149 million.

Financing Activities

Cash Flows From Financing Activities were \$46 million during 2006. We refinanced \$82 million of Pollution Control Bonds. Long-term debt retirements were \$87 million. In addition, we borrowed \$65 million from the Utility Money Pool. We also paid \$20 million in Common Stock Dividends.

Cash Flows From Financing Activities were \$118 million during 2005. We issued \$149 million of Notes Payable. We paid \$25 million in Common Stock Dividends.

Financing Activity

Long-term debt issuances, retirements and principal payments during the first six months of 2006 were:

Issuances

| Type of Debt | Principal Amount (in thousands) | Interest Rate (%) | Due Date |
|-------------------------|------------------------------------|----------------------|----------|
| Pollution Control Bonds | \$ 81,700 | Variable | 2018 |

Retirements and Principal Payments

| Type of Debt | Principal Amount (in thousands) | Interest Rate (%) | Due Date |
|---------------|------------------------------------|----------------------|----------|
| Notes Payable | \$ 3,394 | 4.47 | 2011 |
| Notes Payable | 1,500 | Variable | 2008 |
| | 81,700 | 6.10 | 2018 |

Liquidity

We have solid investment grade ratings, which provide us ready access to capital markets in order to issue new debt and refinance short-term or long-term debt maturities. In addition, we participate in the Utility Money Pool, which provides access to AEP's liquidity.

Summary Obligation Information

A summary of our contractual obligations is included in our 2005 Annual Report and has not changed significantly from year-end except for Energy and Capacity Purchase Contracts. We increased our future obligation in Energy and Capacity Purchase Contracts applicable to our optimization and off-system sales activities by approximately \$15 million annually due to changes within the SIA and CSW Operating Agreement. See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section within Note 3 - Rate Matters.

Significant Factors

Litigation and Regulatory Activity

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome of these proceedings will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases which have a probable likelihood of loss and the loss amount can be estimated. For details on our pending litigation and regulatory proceedings, see Note 4 - Rate Matters, Note 6 - Customer Choice and Industry Restructuring and Note 7 - Commitments and Contingencies in our 2005 Annual Report. Also, see Note 3 - Rate Matters, Note 4 - Customer Choice and Industry Restructuring and Note 5 - Commitments and Contingencies in the "Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries" section. An adverse result in these proceedings has the potential to materially affect our results of operations, financial condition and cash flows.

New Generation

In December 2005, we sought proposals for new peaking, intermediate and base load generation to be online between 2008 and 2011. In May 2006, we announced plans to construct short-term, mid-term and long-term generation to meet the demands of our customers. We will build up to 480 MW of simple-cycle natural gas combustion turbine peaking generation in Tontitown, Arkansas and will build a 480 MW combined-cycle natural gas fired plant at our existing Arsenal Hill Power Plant in Shreveport, Louisiana. We also plan to build a new base load coal or lignite-fueled plant by 2011 to meet the longer-term generation needs of our customers. Preliminary cost estimates for the new facilities are approximately \$1.4 billion. The 2006 through 2008 estimated construction expenditures as disclosed in our 2005 Form 10-K included cost estimates for these new facilities. These new facilities are subject to regulatory approvals from our three state commissions. Construction is expected to begin in 2007.

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

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2005 Annual Report for a discussion of the estimates and judgments required for regulatory

accounting, revenue recognition, the valuation of long-lived assets, pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES**Market Risks**

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

MTM Risk Management Contract Net Assets

The following two tables summarize the various mark-to-market (MTM) positions included in our condensed consolidated balance sheet as of June 30, 2006 and the reasons for changes in our total MTM value as compared to December 31, 2005.

**Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheet
As of June 30, 2006
(in thousands)**

| | MTM Risk Management Contracts | Cash Flow Hedges | Total |
|---|--|-----------------------------|------------------|
| Current Assets | \$ 83,938 | \$ - | \$ 83,938 |
| Noncurrent Assets | 46,983 | - | 46,983 |
| Total MTM Derivative Contract Assets | 130,921 | - | 130,921 |
| Current Liabilities | (64,677) | (90) | (64,767) |
| Noncurrent Liabilities | (35,644) | (20) | (35,664) |
| Total MTM Derivative Contract Liabilities | (100,321) | (110) | (100,431) |
| Total MTM Derivative Contract Net Assets (Liabilities) | \$ 30,600 | \$ (110) | \$ 30,490 |

**MTM Risk Management Contract Net Assets
Six Month Ended June 30, 2006
(in thousands)**

| | |
|---|------------------|
| Total MTM Risk Management Contract Net Assets at December 31, 2005 | \$ 16,387 |
| (Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period | (305) |
| Fair Value of New Contracts at Inception When Entered During the Period (a) | 52 |
| Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During the Period | 8,907 |
| Change in Fair Value Due to Valuation Methodology Changes on Forward Contracts | 139 |
| Changes in Fair Value Due to Market Fluctuations During the Period (b) | (1,694) |
| Changes Due to SIA and CSW Operating Agreement (c) | 11,900 |
| Changes in Fair Value Allocated to Regulated Jurisdictions (d) | (4,786) |
| Total MTM Risk Management Contract Net Assets | 30,600 |
| Net Cash Flow Hedge Contracts | (110) |
| Total MTM Risk Management Contract Net Assets at June 30, 2006 | \$ 30,490 |

- (a) 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.
- (b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
- (c) See “Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement” section of Note 3.
- (d) “Changes in Fair Value Allocated to Regulated Jurisdictions” relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets for those subsidiaries that operate in regulated jurisdictions.

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

The following table presents:

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

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets Fair Value of Contracts as of June 30, 2006 (in thousands)

| | Remainder 2006 | 2007 | 2008 | 2009 | 2010 | After 2010 | Total |
|---|-------------------|------------|----------|----------|--------|---------------|------------|
| Prices Actively Quoted - Exchange Traded Contracts | \$ (1,028) | \$ (2,196) | \$ 695 | \$ (143) | \$ - | \$ - | \$ (2,672) |
| Prices Provided by Other External Sources - OTC Broker Quotes (a) | 6,966 | 7,419 | 10,919 | 465 | - | - | 25,769 |
| Prices Based on Models and Other Valuation Methods (b) | 10,611 | (796) | (2,276) | (31) | (3) | (2) | 7,503 |
| Total | \$ 16,549 | \$ 4,427 | \$ 9,338 | \$ 291 | \$ (3) | \$ (2) | \$ 30,600 |

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

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

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

We employ the use of interest rate derivative transactions to manage interest rate risk related to existing variable rate debt and to manage interest rate exposure on anticipated borrowings of fixed-rate debt. We do not hedge all interest rate risk.

The following table provides the detail on designated, effective cash flow hedges included in AOCI on our Condensed Consolidated Balance Sheets and the reasons for the changes from December 31, 2005 to June 30, 2006. Only contracts designated as cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts that are not designated as effective cash flow hedges are marked-to-market and included in the previous risk management tables. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity
Six Months Ended June 30, 2006
(in thousands)

| | Power | Interest Rate | Total |
|--|-------|---------------|------------|
| Beginning Balance in AOCI December 31, 2005 | (736) | \$ (5,116) | \$ (5,852) |
| Changes in Fair Value | 14 | (54) | (40) |
| Impact due to Change in SIA (a) | 591 | - | 591 |
| Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled | 144 | 269 | 413 |
| Ending Balance in AOCI June 30, 2006 | \$ 13 | \$ (4,901) | \$ (4,888) |

(a) See "Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreement" section of Note 3.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a \$532 thousand loss.

Credit Risk

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

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at June 30, 2006, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

| Six Months Ended June 30, 2006 (in thousands) | Twelve Months Ended December 31, 2005 (in thousands) |
|---|--|
|---|--|

| End | High | Average | Low | End | High | Average | Low |
|------------|-------------|----------------|------------|------------|-------------|----------------|------------|
| \$705 | \$1,674 | \$638 | \$68 | \$363 | \$604 | \$287 | \$104 |

VaR Associated with Debt Outstanding

We also utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The risk of potential loss in fair value attributable to our exposure to interest rates primarily related to long-term debt with fixed interest rates was \$28 million and \$31 million at June 30, 2006 and December 31, 2005, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period; therefore, a near term change in interest rates should not negatively affect our results of operations or consolidated financial position.

**SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME**
For the Three and Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

| | Three Months Ended | | Six Months Ended | |
|---|--------------------|------------------|------------------|------------------|
| | 2006 | 2005 | 2006 | 2005 |
| REVENUES | | | | |
| Electric Generation, Transmission and Distribution | \$ 349,650 | \$ 326,046 | \$ 643,643 | \$ 555,854 |
| Sales to AEP Affiliates | 9,414 | 6,837 | 20,179 | 23,959 |
| Other | 420 | (32) | 794 | 249 |
| TOTAL | 359,484 | 332,851 | 664,616 | 580,062 |
| EXPENSES | | | | |
| Fuel and Other Consumables for Electric Generation | 118,271 | 116,397 | 208,932 | 206,815 |
| Purchased Electricity for Resale | 44,884 | 32,803 | 74,102 | 46,183 |
| Purchased Electricity from AEP Affiliates | 16,826 | 22,003 | 40,163 | 27,867 |
| Other Operation | 53,299 | 47,496 | 103,082 | 92,111 |
| Maintenance | 22,231 | 27,645 | 46,888 | 43,360 |
| Depreciation and Amortization | 32,876 | 33,257 | 65,410 | 65,650 |
| Taxes Other Than Income Taxes | 16,165 | 15,887 | 32,147 | 31,550 |
| TOTAL | 304,552 | 295,488 | 570,724 | 513,536 |
| OPERATING INCOME | 54,932 | 37,363 | 93,892 | 66,526 |
| Other Income | 840 | 1,146 | 1,568 | 2,250 |
| Interest Expense | (14,073) | (12,901) | (26,844) | (25,681) |
| INCOME BEFORE INCOME TAXES AND MINORITY INTEREST EXPENSE | 41,699 | 25,608 | 68,616 | 43,095 |
| Income Tax Expense | 12,491 | 5,490 | 21,314 | 9,886 |
| Minority Interest Expense | 896 | 814 | 1,118 | 1,700 |
| NET INCOME | 28,312 | 19,304 | 46,184 | 31,509 |
| Preferred Stock Dividend Requirements | 58 | 58 | 115 | 115 |
| EARNINGS APPLICABLE TO COMMON STOCK | \$ 28,254 | \$ 19,246 | \$ 46,069 | \$ 31,394 |

The common stock of SWEPCo is owned by a wholly-owned subsidiary of AEP.

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2006 and 2005
(in thousands)
(Unaudited)

| | Common Stock | Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total |
|--|-----------------|--------------------|----------------------|---|----------------|
| DECEMBER 31, 2004 | \$ 135,660 | \$ 245,003 | \$ 389,135 | \$ (1,180) | \$ 768,618 |
| Common Stock Dividends | | | (25,000) | | (25,000) |
| Preferred Stock Dividends | | | (115) | | (115) |
| TOTAL | | | | | 743,503 |
| COMPREHENSIVE INCOME | | | | | |
| Other Comprehensive Loss, Net of Taxes: | | | | | |
| Cash Flow Hedges, Net of Tax of \$2,807 | | | | (5,212) | (5,212) |
| NET INCOME | | | 31,509 | | 31,509 |
| TOTAL COMPREHENSIVE INCOME | | | | | 26,297 |
| JUNE 30, 2005 | \$ 135,660 | \$ 245,003 | \$ 395,529 | \$ (6,392) | \$ 769,800 |
| DECEMBER 31, 2005 | \$ 135,660 | \$ 245,003 | \$ 407,844 | \$ (6,129) | \$ 782,378 |
| Common Stock Dividends | | | (20,000) | | (20,000) |
| Preferred Stock Dividends | | | (115) | | (115) |
| TOTAL | | | | | 762,263 |
| COMPREHENSIVE INCOME | | | | | |
| Other Comprehensive Income, Net of Taxes: | | | | | |
| Cash Flow Hedges, Net of Tax of \$519 | | | | 964 | 964 |
| NET INCOME | | | 46,184 | | 46,184 |
| TOTAL COMPREHENSIVE INCOME | | | | | 47,148 |
| JUNE 30, 2006 | \$ 135,660 | \$ 245,003 | \$ 433,913 | \$ (5,165) | \$ 809,411 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

**SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS**

ASSETS

June 30, 2006 and December 31, 2005

(in thousands)

(Unaudited)

| | 2006 | 2005 |
|---|---------------------|---------------------|
| CURRENT ASSETS | | |
| Cash and Cash Equivalents | \$ 2,108 | \$ 3,049 |
| Accounts Receivable: | | |
| Customers | 75,318 | 47,515 |
| Affiliated Companies | 35,105 | 49,226 |
| Miscellaneous | 9,596 | 7,984 |
| Allowance for Uncollectible Accounts | (180) | (548) |
| Total Accounts Receivable | 119,839 | 104,177 |
| Fuel | 59,540 | 40,333 |
| Materials and Supplies | 38,617 | 34,821 |
| Risk Management Assets | 83,938 | 47,319 |
| Regulatory Asset for Under-Recovered Fuel Costs | 11,595 | 51,387 |
| Margin Deposits | 66,578 | 13,740 |
| Prepayments and Other | 17,369 | 20,270 |
| TOTAL | 399,584 | 315,096 |
| PROPERTY, PLANT AND EQUIPMENT | | |
| Electric: | | |
| Production | 1,677,767 | 1,660,392 |
| Transmission | 659,965 | 645,297 |
| Distribution | 1,185,955 | 1,153,026 |
| Other | 450,255 | 443,749 |
| Construction Work in Progress | 121,433 | 104,175 |
| Total | 4,095,375 | 4,006,639 |
| Accumulated Depreciation and Amortization | 1,801,261 | 1,776,216 |
| TOTAL - NET | 2,294,114 | 2,230,423 |
| OTHER NONCURRENT ASSETS | | |
| Regulatory Assets | 105,906 | 81,776 |
| Long-term Risk Management Assets | 46,983 | 39,796 |
| Employee Benefits and Pension Assets | 80,967 | 83,330 |
| Deferred Charges and Other | 64,634 | 46,926 |
| TOTAL | 298,490 | 251,828 |
| TOTAL ASSETS | \$ 2,992,188 | \$ 2,797,347 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

**SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
June 30, 2006 and December 31, 2005
(Unaudited)**

| CURRENT LIABILITIES | 2006 | 2005 |
|--|-----------------------|---------------------|
| | (in thousands) | |
| Advances from Affiliates | \$ 93,083 | \$ 28,210 |
| Accounts Payable: | | |
| General | 100,275 | 71,138 |
| Affiliated Companies | 82,145 | 53,019 |
| Short-term Debt - Nonaffiliated | 10,249 | 1,394 |
| Long-term Debt Due Within One Year - Nonaffiliated | 19,470 | 15,755 |
| Risk Management Liabilities | 64,767 | 45,098 |
| Customer Deposits | 54,611 | 50,848 |
| Accrued Taxes | 61,952 | 42,799 |
| Other | 60,368 | 82,699 |
| TOTAL | 546,920 | 390,960 |
| NONCURRENT LIABILITIES | | |
| Long-term Debt - Nonaffiliated | 670,457 | 678,886 |
| Long-term Debt - Affiliated | 50,000 | 50,000 |
| Long-term Risk Management Liabilities | 35,664 | 27,083 |
| Deferred Income Taxes | 389,969 | 409,513 |
| Regulatory Liabilities and Deferred Investment Tax Credits | 355,092 | 320,066 |
| Deferred Credits and Other | 128,790 | 131,477 |
| TOTAL | 1,629,972 | 1,617,025 |
| TOTAL LIABILITIES | 2,176,892 | 2,007,985 |
| Minority Interest | 1,185 | 2,284 |
| Cumulative Preferred Stock Not Subject to Mandatory Redemption | 4,700 | 4,700 |
| Commitments and Contingencies (Note 5) | | |
| COMMON SHAREHOLDER'S EQUITY | | |
| Common Stock - \$18 Par Value Per Share: | | |
| Authorized - 7,600,000 Shares | | |
| Outstanding - 7,536,640 Shares | 135,660 | 135,660 |
| Paid-in Capital | 245,003 | 245,003 |
| Retained Earnings | 433,913 | 407,844 |
| Accumulated Other Comprehensive Income (Loss) | (5,165) | (6,129) |
| TOTAL | 809,411 | 782,378 |
| TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY | \$ 2,992,188 | \$ 2,797,347 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

**SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS**

For the Six Months Ended June 30, 2006 and 2005

(in thousands)

(Unaudited)

| | 2006 | 2005 |
|---|------------------|------------------|
| OPERATING ACTIVITIES | | |
| Net Income | \$ 46,184 | \$ 31,509 |
| Adjustments for Noncash Items: | | |
| Depreciation and Amortization | 65,410 | 65,650 |
| Deferred Income Taxes | (15,511) | 176 |
| Mark-to-Market of Risk Management Contracts | (14,213) | 13,031 |
| Deferred Property Taxes | (18,593) | (19,047) |
| Change in Other Noncurrent Assets | 16,704 | 3,269 |
| Change in Other Noncurrent Liabilities | (16,419) | (20,799) |
| Changes in Components of Working Capital: | | |
| Accounts Receivable, Net | (15,662) | 13,224 |
| Fuel, Materials and Supplies | (23,003) | 1,562 |
| Accounts Payable | 60,158 | 27,729 |
| Accrued Taxes, Net | 19,153 | 959 |
| Over/Under Fuel Recovery, Net | 37,377 | (24,890) |
| Margin Deposits | (52,838) | 2,078 |
| Other Current Assets | 3,560 | 3,670 |
| Other Current Liabilities | (16,153) | 1,164 |
| Net Cash Flows From Operating Activities | 76,154 | 99,285 |
| INVESTING ACTIVITIES | | |
| Construction Expenditures | (122,616) | (72,490) |
| Change in Advances to Affiliates, Net | - | (148,971) |
| Other | (659) | 4,993 |
| Net Cash Flows Used For Investing Activities | (123,275) | (216,468) |
| FINANCING ACTIVITIES | | |
| Issuance of Long-term Debt - Nonaffiliated | 80,593 | 148,895 |
| Change in Short-term Debt, Net - Nonaffiliated | 8,855 | - |
| Retirement of Long-term Debt - Nonaffiliated | (86,594) | (4,915) |
| Change in Advances from Affiliates, Net | 64,873 | - |
| Principal Payments for Capital Lease Obligations | (1,432) | (806) |
| Dividends Paid on Common Stock | (20,000) | (25,000) |
| Dividends Paid on Cumulative Preferred Stock | (115) | (115) |
| Net Cash Flows From Financing Activities | 46,180 | 118,059 |
| Net Increase (Decrease) in Cash and Cash Equivalents | (941) | 876 |
| Cash and Cash Equivalents at Beginning of Period | 3,049 | 3,715 |
| Cash and Cash Equivalents at End of Period | \$ 2,108 | \$ 4,591 |
| SUPPLEMENTARY INFORMATION | | |
| Cash Paid for Interest, Net of Capitalized Amounts | \$ 24,840 | \$ 22,279 |

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| | | |
|--|--------|--------|
| Cash Paid for Income Taxes, Net of Refunds | 42,788 | 35,969 |
| Noncash Acquisitions Under Capital Leases | 5,537 | 2,035 |
| Construction Expenditures Included in Accounts Payable at June 30, | 8,326 | 2,759 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries.

**SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
INDEX TO CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT
SUBSIDIARIES**

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

| | Footnote Reference |
|--|-------------------------------|
| Significant Accounting Matters | Note 1 |
| New Accounting Pronouncements | Note 2 |
| Rate Matters | Note 3 |
| Customer Choice and Industry Restructuring | Note 4 |
| Commitments and Contingencies | Note 5 |
| Guarantees | Note 6 |
| Company-wide Staffing and Budget Review | Note 7 |
| Benefit Plans | Note 9 |
| Income Taxes | Note 10 |
| Business Segments | Note 11 |
| Financing Activities | Note 12 |

CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to condensed financial statements that follow are a combined presentation for the Registrant Subsidiaries. The following list indicates the registrants to which the footnotes apply:

| | | |
|-----|--|--|
| 1. | Significant Accounting Matters | AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC |
| 2. | New Accounting Pronouncements | AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC |
| 3. | Rate Matters | APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC |
| 4. | Customer Choice and Industry Restructuring | CSPCo, OPCo, SWEPCo, TCC, TNC |
| 5. | Commitments and Contingencies | AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC |
| 6. | Guarantees | AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC |
| 7. | Company-wide Staffing and Budget Review | AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC |
| 8. | Assets Held for Sale | TCC |
| 9. | Benefit Plans | APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC |
| 10. | Income Taxes | PSO, SWEPCo, TCC, TNC |
| 11. | Business Segments | AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC |
| 12. | Financing Activities | AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC |

1. SIGNIFICANT ACCOUNTING MATTERS**General**

The accompanying unaudited interim financial statements should be read in conjunction with the 2005 Annual Report as incorporated in and filed with the 2005 Form 10-K.

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

Components of Accumulated Other Comprehensive Income (Loss)

Accumulated Other Comprehensive Income (Loss) is included on the condensed balance sheets in the common shareholder's equity section. The components of Accumulated Other Comprehensive Income (Loss) for Registrant Subsidiaries as of June 30, 2006 and December 31, 2005 are shown in the following table.

| Components | June 30, 2006 | December 31, 2005 |
|-----------------------------------|--------------------------|----------------------------------|
| | (in thousands) | |
| Cash Flow Hedges: | | |
| APCo | \$ 1,577 | \$ (16,421) |
| CSPCo | 6,002 | (859) |
| I&M | 5,234 | (3,467) |
| KPCo | 2,550 | (194) |
| OPCo | 11,355 | 755 |
| PSO | (416) | (1,112) |
| SWEPCo | (4,888) | (5,852) |
| TCC | - | (224) |
| TNC | 2,429 | (111) |
| Minimum Pension Liability: | | |
| APCo | \$ (189) | \$ (189) |
| CSPCo | (21) | (21) |
| I&M | (102) | (102) |
| KPCo | (29) | (29) |
| PSO | (152) | (152) |
| SWEPCo | (277) | (277) |
| TCC | (928) | (928) |
| TNC | (393) | (393) |

Related Party Transactions

The amounts of power purchased from Ohio Valley Electric Corporation, which is 43.47 % owned by AEP and CSPCo, were:

| Three Months Ended June 30, | Six Months Ended June 30, |
|--|--------------------------------------|
|--|--------------------------------------|

| Company | 2006 | 2005 | 2006 | 2005 |
|---------|----------------|-----------|-----------|-----------|
| | (in thousands) | | | |
| APCo | \$ 20,680 | \$ 18,311 | \$ 42,654 | \$ 35,263 |
| CSPCo | 5,899 | 5,054 | 11,564 | 9,648 |
| I&M | 10,512 | 8,671 | 19,064 | 14,784 |
| OPCo | 20,693 | 16,091 | 39,323 | 31,054 |

CSPCo entered into a ten year Power Purchase Agreement (PPA) with Sweeny, on behalf of the AEP West companies, from January 1, 2005 to December 31, 2014. The PPA is for unit contingent power up to a maximum of 315 MW. The delivery point for the power under the PPA is in TCC's system. The power is sold in ERCOT. The purchase of Sweeny power and its sale to nonaffiliates are shared among the AEP West companies under the CSW Operating Agreement. See "Allocation Agreement between AEP East Companies and AEP West Companies and CSW Operating Agreement" section of Note 3. Also see Note 17 of the 2005 Annual Report for a discussion of the CSW Operating Agreement. The purchases from Sweeny were:

| Company | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---------|--------------------------------|-----------|------------------------------|-----------|
| | 2006 | 2005 | 2006 | 2005 |
| | (in thousands) | | | |
| PSO | \$ 14,443 | \$ 10,152 | \$ 26,136 | \$ 23,449 |
| SWEPCo | 13,208 | 12,164 | 30,755 | 19,658 |
| TCC | 121 | 1,285 | 703 | 3,357 |
| TNC | 398 | 8,025 | 4,229 | 13,677 |

Reclassifications

Certain prior period financial statement items have been reclassified to conform to current period presentation.

The Registrant Subsidiaries' Statements of Operations were converted from a utility format presentation where only regulated cost-of-service items were reflected in Operating Income to a commercial format presentation where nonutility items are reflected as components of Operating Income.

These revisions had no impact on previously reported results of operations, financial condition or changes in shareholders' equity.

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of exposure drafts or final pronouncements, we thoroughly review the new accounting literature to determine its relevance, if any, to our business. The following represents a summary of new pronouncements issued or implemented in 2006 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. 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 Opinion No. 25, "Accounting for Stock Issued to Employees." The Registrant Subsidiaries recorded insignificant cumulative effects of a change in accounting principle in the first quarter of 2006 for the effects of initially applying the statement, primarily reflected in Other Operation on their financial statements.

In March 2005, the SEC issued Staff Accounting Bulletin No. 107, "Share-Based Payment" (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. Also, the FASB issued three FASB Staff Positions (FSP) during 2005 and one in February 2006 that provided additional implementation guidance. The Registrant Subsidiaries applied the principles of SAB 107 and the applicable FSPs in conjunction with their adoption of SFAS 123R.

The Registrant Subsidiaries adopted SFAS 123R in the first quarter of 2006 using the modified prospective method. This method requires them to record compensation expense for all awards granted after the time of adoption and 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 is based on the grant-date fair value of the equity award. Stock-based compensation expense recognized during the period is based on the value of the portion of share-based payment awards that is ultimately expected to vest during the period. Stock-based compensation expense recognized in the Registrant Subsidiaries' financial statements for the three and six months ended June 30, 2006 includes compensation expense for share-based payment awards granted prior to, but not yet vested as of, January 1, 2006 based on the grant date fair value estimated in accordance with the pro forma provisions of SFAS 123 and compensation expense for the share-based payment awards granted subsequent to January 1, 2006 based on the grant date fair value estimated in accordance with the provisions of SFAS 123R. Implementation of SFAS 123R did not materially affect the Registrant Subsidiaries' results of operations, cash flows or financial condition.

EITF Issue 06-3 "How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation)" (EITF 06-3)

In June 2006, the EITF reached a consensus on the income statement presentation of various types of taxes. The scope of this issue includes any tax assessed by a governmental authority that is directly imposed on a revenue-producing transaction between a seller and a customer and may include, but is not limited to, sales, use, value added, and some excise taxes. The presentation of taxes within the scope of this issue on either a gross (included in revenues and costs) or a net (excluded from revenues) basis is an accounting policy decision that should be disclosed pursuant to APB Opinion No. 22, "Disclosure of Accounting Policies." The EITF's decision on gross/net presentation requires that any such taxes reported on a gross basis be disclosed on an aggregate basis in interim and annual financial statements, for each period for which an income statement is presented, if those amounts are significant.

EITF 06-3 is effective for fiscal years beginning after December 15, 2006. Management has not completed the process of determining the effect of this interpretation on the financial statements.

FASB Interpretation No. 48 "Accounting for Uncertainty in Income Taxes" (FIN 48)

In July 2006, the FASB issued FIN 48 which clarifies the application of SFAS 109, "Accounting for Income Taxes." FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements by prescribing a recognition threshold (whether a tax position is more likely than not to be sustained) without which, the benefit of that position is not recognized in the financial statements. It requires a measurement determination for recognized tax positions based on the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition.

FIN 48 requires that the cumulative effect of applying this interpretation be reported and disclosed as an adjustment to the opening balance of retained earnings for that fiscal year and presented separately. FIN 48 is effective for fiscal years beginning after December 15, 2006. Management has not completed the process of determining the effect of this interpretation on the financial statements.

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 and financial position that may result from any such future changes. The FASB is currently working on several projects including fair value measurements, business combinations, revenue recognition, pension and postretirement benefit plans, liabilities and equity, leases, insurance, subsequent events and related tax impacts. We also expect to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on future results of operations and financial position.

3. RATE MATTERS

The Rate Matters note within the 2005 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact results of operations and cash flows. Rate matters that are not believed to be reasonably likely to affect future results of operations and cash flows are not included in this report or the 2005 Annual Report. The following sections discuss ratemaking developments in 2006 updating the 2005 Annual Report.

APCo Virginia Environmental and Reliability Costs - Affecting APCo

The Virginia Electric Restructuring Act includes a provision that permits recovery, during the extended capped rate period ending December 31, 2010, of incremental environmental compliance and transmission and distribution (T&D) system reliability (E&R) costs prudently incurred after July 1, 2004. In 2005, APCo filed a request with the Virginia SCC and updated it through supplemental testimony seeking recovery of \$21 million of incremental E&R costs incurred from July 2004 through September 2005. Through June 30, 2006, APCo deferred \$37 million of incurred incremental E&R costs.

In January 2006, the Virginia SCC staff proposed that APCo be allowed to increase its electric rates at an ongoing level of \$20 million to recover current, rather than past, incremental E&R costs. The staff proposal would effectively disallow the recovery of costs incurred prior to the authorization and implementation of new rates, including all incremental E&R costs that were deferred as a regulatory asset. At the E&R hearings, which concluded in March 2006, the staff amended its testimony to recommend a \$24 million increase in APCo's ongoing rates. Management believes the staff's proposal is contrary to the statute and an October 2005 Virginia SCC order, which denied APCo's original request to recover projected costs in favor of the Virginia SCC's interpretation that the law only permits recovery of actual incremental E&R costs that the commission finds prudent.

If the Virginia SCC properly implements the statute and its related October 2005 order, notwithstanding use of estimates, APCo should be able to recover all of its prudently incurred E&R costs. However, if the Virginia SCC reverses its position and adopts the staff's recommendations or denies recovery of any of APCo's deferred E&R costs, APCo's future results of operations and cash flows would be adversely impacted.

APCo Virginia Base Rate Case - Affecting APCo

In May 2006, APCo filed a request with the Virginia SCC seeking an increase in base rates of \$225 million to recover increasing costs including a return on equity of 11.5%. In addition, APCo requested to move off-system sales margins, currently credited to customers through base rates, to the fuel factor where they can be adjusted annually. APCo also proposed to share the off-system sales margins with the customers. This proposed off-system sales fuel rate credit of \$27 million partially offsets the \$225 million requested increase in base rates for a net increase in revenues of \$198 million. The major components of the \$225 million rate request include \$73 million for the impact of removing off-system sales margins from the rate year ending September 30, 2007, \$60 million due to projected net plant additions through September 30, 2007 and \$48 million for return on equity. In May 2006, the Virginia SCC issued an order, consistent with Virginia law, placing the full requested base rate increase of \$225 million into effect October 2,

2006, subject to refund. Hearings are scheduled to begin in December 2006. We are unable to predict the ultimate effect of this filing on APCo's future revenues, cash flows and financial condition.

APCo West Virginia Rate Case - Affecting APCo

In July 2006, the WVPSC approved the settlement agreement APCo and WPCo reached with the WVPSC staff and intervenors in the West Virginia rate case filed in 2005. The settlement agreement provided for an initial overall increase in APCo's rates of \$40 million effective July 28, 2006 comprised of:

- A \$50 million increase in Expanded Net Energy Cost (ENEC) for fuel and purchased power expenses;
- A \$21 million special construction surcharge providing recovery of the costs of scrubbers and the Wyoming-Jacksons Ferry 765 kV line to date;
- A \$16 million general base rate reduction based on a return of equity of 10.5%, of which \$9 million relates to a reduction in depreciation expense which affects cash flows but not earnings; and
- A \$15 million credit to refund a portion of deferred prior over-recoveries of ENEC costs, currently recorded in regulatory liabilities on the Condensed Consolidated Balance Sheets. Therefore, this item impacts cash flows but has no effect on earnings.

In addition, the agreement provides a surcharge mechanism that allows APCo to adjust its rates annually for the timely recovery in each of the next three years of the incremental cost of ongoing environmental investments in scrubbers at Mountaineer and John Amos power plants and the costs of the Wyoming-Jackson Ferry line. Although the amount of these annual surcharge increases cannot be determined until the incremental costs are known and reviewed by the WVPSC, management estimates that they will result in an annual increase in APCo's revenues of \$32 million effective July 1, 2007, \$13 million effective July 1, 2008 and \$16 million effective July 1, 2009.

The settlement further provides for the reinstatement of the ENEC mechanism effective July 1, 2006 with over/under recovery deferral accounting and annual ENEC proceedings to affect annual rate adjustments for changes in fuel and purchased power costs beginning in 2007. The settlement provides for the return to customers of the remaining portion of the prior ENEC regulatory liability including interest at LIBOR rate on the unrefunded balance in future ENEC proceedings.

I&M Depreciation Study Filing- Affecting I&M

In December 2005, I&M filed a petition with the IURC seeking authorization to revise its book depreciation rates applicable to its electric utility plant in service effective January 1, 2006. Based on a depreciation study included in the filing, I&M recommended a decrease in pretax annual depreciation expense of approximately \$69 million on an Indiana jurisdictional basis reflecting an NRC-approved 20-year extension of the Cook Plant licenses for Units 1 and 2 and an extension of the service life of the Tanners Creek coal-fired generating units. This petition is not a request for a change in customers' electric service rates. Intervenors filed testimony in March 2006 arguing that the book depreciation rates should not be revised until the Indiana rate cap ends in July 2007 or until base rates are revised. I&M filed its rebuttal testimony in April 2006. A public hearing was held in May 2006 and the final brief was filed in June 2006. As proposed by I&M, the book depreciation expense reduction would increase I&M's earnings, but would not impact its cash flows until electric service rates are revised. If approved by the IURC, I&M will currently reduce its book depreciation expense from the approved effective date forward. I&M is awaiting the IURC order.

KPCo Environmental Surcharge Filing - Affecting KPCo

In June 2006, KPCo filed a notice of its intent to file an amended environmental compliance plan and revised tariff to implement an adjusted environmental surcharge on or after August 16, 2006.

KPCo Rate Filing - Affecting KPCo

In March 2006, the KPSC approved the settlement agreement in KPCo's 2005 base rate case. The approved agreement provides for a \$41 million annual increase in revenues effective March 30, 2006 and the retention of the existing environmental surcharge tariff. No return on equity is specified by the settlement terms except to note that KPCo will use a 10.5% return on equity to calculate the environmental surcharge tariff and AFUDC.

PSO Fuel and Purchased Power and its Possible Impact on AEP East companies and AEP West companies

In 2002, PSO under-recovered \$44 million 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 proposed collection of those reallocated costs over 18 months. In August 2003, the OCC staff filed testimony recommending PSO recover \$42 million of the reallocated purchased power costs over three years and PSO reduced its regulatory asset deferral by \$2 million. The OCC subsequently expanded the case to include a full prudence review of PSO's 2001 through 2003 fuel and purchased power practices. In January 2006, the OCC staff and intervenors issued supplemental testimony alleging that AEP deviated from the FERC-approved method of allocating off-system sales margins between AEP East companies and AEP West companies and among AEP West companies. The OCC staff proposed that the OCC offset the \$42 million of under-recovered fuel with their proposed reallocation of off-system sales margins of \$27 million to \$37 million and with \$9 million attributed to wholesale customers, which they claimed had not been refunded. In February 2006, the OCC staff filed a report concluding that the \$9 million of reallocated purchased power costs assigned to wholesale customers has been refunded, thus removing that issue from their recommendation.

In 2004, an Oklahoma ALJ found that the OCC lacks authority to examine whether PSO deviated from the FERC-approved allocation methodology and held that any such complaints should be addressed at the FERC. The OCC has not ruled on appeals by intervenors of the ALJ's finding. In September 2005, the United States District Court for the Western District of Texas issued an order in a TNC fuel proceeding, preempting the PUCT from reallocating off-system sales margins between the AEP East companies and AEP West companies. The federal court agreed that the FERC has sole jurisdiction over that allocation. The PUCT appealed the ruling.

PSO does not agree with the intervenors' and the OCC staff's recommendations and proposals and will defend its position vigorously. If the OCC denies recovery of any portion of the \$42 million under-recovery of reallocated costs or offsets under-recovered fuel deferrals with additional reallocated off-system sales margins, PSO's future results of operations and cash flows could be adversely affected. However, if the position taken by the federal court in Texas applies to PSO's case, the OCC could be preempted from disallowing fuel recoveries for alleged improper allocations of off-system sales margins between AEP East companies and AEP West companies. The OCC or another party may file a complaint at the FERC alleging the allocation of off-system sales margins adopted by PSO is improper which could result in an adverse effect on future results of operations and cash flows for the AEP East companies. To date, there has been no claim asserted at the FERC that AEP deviated from the approved allocation methodologies. Management is unable to predict the ultimate effect, if any, of these Oklahoma fuel clause proceedings and any future FERC proceedings on the AEP East companies' and AEP West companies' future results of operations, cash flows and financial condition.

In June 2005, the OCC issued an order directing its staff to conduct a prudence review of PSO's fuel and purchased power practices for the year 2003. Both the OCC staff and Attorney General of Oklahoma filed testimony, finding no disallowances in the test year data. However, an intervenor filed testimony in June 2006, proposing the disallowance of \$22 million in fuel costs based on a historical review of potential hedging opportunities that existed during the year. A hearing is scheduled for August 2006.

In February 2006, a law was enacted requiring the OCC to conduct prudence reviews on all generation and fuel procurement processes, practices and costs on either a two or three-year cycle depending on the number of customers

served. PSO is subject to biennial reviews. The OCC staff indicated that it expects the review process to begin in the fourth quarter of 2006.

Management cannot predict the outcome of this review or planned future reviews, but believes that PSO's fuel and purchased power procurement practices and costs are prudent and properly incurred. If the OCC disagrees and disallows fuel or purchased power costs including the unrecovered 2002 reallocation of such costs incurred by PSO, it would have an adverse effect on PSO's future results of operations and cash flows.

SWEP Co Louisiana Fuel Inquiry - Affecting SWEP Co

In March 2006, the Louisiana Public Service Commission (LPSC) closed its inquiry into SWEP Co's fuel and purchased power procurement activities during the period January 1, 2005 through October 31, 2005. The LPSC approved the LPSC staff's report, which concluded that SWEP Co's activities were appropriate and did not identify any disallowances or areas for improvement.

SWEP Co PUCT Staff Review of Earnings - Affecting SWEP Co

In October 2005, the staff of the PUCT reported the results of its review of SWEP Co's year-end 2004 earnings. Based on the staff's adjustments to the information submitted by SWEP Co, the report indicates that SWEP Co is receiving excess revenues of approximately \$15 million. The staff engaged SWEP Co in discussions to reconcile the earnings calculation and to consider possible ways to address the results. After those discussions, the PUCT staff informed SWEP Co in April 2006 that they would not pursue the matter further.

SWEP Co Louisiana Compliance Filing - Affecting SWEP Co

In October 2002, SWEP Co filed with the LPSC detailed financial information typically utilized in a revenue requirement filing, including a jurisdictional cost of service. This filing was required by the LPSC as a result of its order approving the merger between AEP and CSW. In April 2004, at the request of the LPSC, SWEP Co filed updated financial information with a test year ending December 31, 2003. Both filings indicated that SWEP Co's rates should not be reduced. Subsequently, direct testimony was filed by the LPSC staff's consultants recommending a \$15 million reduction in SWEP Co's Louisiana jurisdictional base rates based on an 8.95% return on equity and the disallowance of projected increased pension expense. Due to multiple delays, in April 2006, the LPSC and SWEP Co agreed to update the financial information based on a 2005 test year. SWEP Co filed updated financial review schedules in May 2006 showing a return on equity of 9.44%. In July 2006, the LPSC staff's consultants filed direct testimony recommending a base rate reduction in the range of \$12 million to \$20 million for SWEP Co's Louisiana jurisdiction customers, which included a 10% return on equity. The recommended reduction range is subject to SWEP Co validating certain on-going operations and maintenance expense levels and the recommended base rate reduction does not include the impact of a proposed consolidated federal income tax adjustment, which would increase the proposed rate reduction. SWEP Co intends to file rebuttal testimony refuting the consultants' recommendations. Hearings are scheduled for October 2006. A decision is not expected until late 2006 at the earliest. At this time, management is unable to predict the outcome of this proceeding. If a rate reduction is ultimately ordered, it would adversely impact SWEP Co's future results of operations and cash flows.

ERCOT Price-to-Beat (PTB) Fuel Factor Appeal - Affecting TCC and TNC

Several parties including the Office of Public Utility Counsel and cities served by both TCC and TNC appealed the PUCT's December 2001 orders establishing initial PTB fuel factors for Mutual Energy CPL and Mutual Energy WTU (TCC's and TNC's former affiliated REPs, respectively). In June 2003, the District Court ruled the PUCT record lacked substantial evidence regarding the effect of loss of load due to retail competition on the generation requirements of both Mutual Energy WTU and Mutual Energy CPL and on the PTB rates. In an opinion issued on July 28, 2005, the Texas Court of Appeals reversed the District Court. The cities appealed the appeals court decision to the Texas

Supreme Court. Management cannot predict the outcome of further appeals, but a reversal of the favorable court of appeals decision regarding the loss of load issue could result in the issue being returned to the PUCT for further consideration. If the PUCT were to reverse its decision and order refunds of PTB revenues, it could adversely impact TCC's and TNC's results of operations and cash flows.

RTO Formation/Integration - Affecting APCo, CSPCo, I&M, KPCo and OPCo

In 2005, the FERC approved the amortization of approximately \$18 million of deferred RTO formation/integration costs not billed by PJM over 15 years and \$17 million of deferred PJM-billed integration costs over 10 years. The total amortization related to such costs was \$1 million in both the second quarter of 2006 and 2005. In the first half of both 2006 and 2005, total amortization related to such costs was \$2 million.

The AEP East companies' deferred unamortized RTO formation/integration costs were as follows:

| | June 30, 2006 | | December 31, 2005 | |
|-------|---------------------------------|---|---------------------------------|---|
| | PJM-Billed Integration Costs | Non-PJM Billed Formation/ Integration Costs | PJM-Billed Integration Costs | Non-PJM Billed Formation/ Integration Costs |
| | (in millions) | | | |
| APCo | \$ 3.8 | \$ 4.9 | \$ 4.1 | \$ 4.9 |
| CSPCo | 1.5 | 1.9 | 1.7 | 1.9 |
| I&M | 3.0 | 3.5 | 3.2 | 3.7 |
| KPCo | 0.9 | 1.1 | 1.0 | 1.1 |
| OPCo | 4.4 | 5.1 | 4.7 | 5.1 |

In a December 2005 order, the FERC approved the inclusion of a separate rate in the PJM AEP zone OATT to recover the amortization of deferred RTO formation/integration costs not billed by PJM of \$2 million per year. The AEP East companies will be responsible for paying the majority of the amortized costs assigned by the FERC to the AEP East zone since their internal load is the bulk (about 85%) of the transmission load in the AEP zone.

In May 2006, the FERC approved a settlement that provides for recovery over a ten-year period of 41% of deferred PJM-billed and incurred integration costs and related carrying charges from the PJM region outside of the AEP zone and the remaining 59% from within the AEP zone. As a result, the AEP East companies are responsible for paying approximately 50% of the amortized PJM-billed integration costs (59% of costs to be recovered within the AEP zone times 85% internal load factor within the AEP zone) for their internal load usage of the transmission system.

CSPCo, OPCo and KPCo are recovering the amortization of RTO formation/integration costs billed to AEP East companies in Ohio and Kentucky. APCo received approval to include the amortization of RTO formation/integration costs in retail rates in West Virginia effective July 28, 2006. In Virginia, APCo recently filed a base rate case, which includes recovery of these costs. In Indiana, I&M is subject to a rate cap until June 30, 2007.

Until APCo and I&M can adjust their retail rates to recover the amortization of their RTO-related deferred costs, their results of operations and cash flows will be adversely impacted. APCo will recover its RTO amortizations starting in late July 2006 in West Virginia and is scheduled to commence recovery in early October 2006 in Virginia. The new Virginia rates will be subject to refund. If the Virginia or Indiana commissions disallow recovery of any portion of the billed amortization of deferred RTO formation/integration costs, it would adversely impact APCo's and/or I&M's future results of operations and cash flows.

Transmission Rate Proceedings at the FERC - Affecting APCo, CSPCo, I&M, KPCo and OPCo

SECA Revenue Subject to Refund

In accordance with FERC orders, the AEP East companies collected SECA rates to mitigate lost through-and-out transmission service (T&O) revenues from December 1, 2004 through March 31, 2006, when SECA rates expired. Intervenor objected to the SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and indicated that the SECA rate revenues are collected subject to refund or surcharge.

The AEP East companies recognized net SECA revenues as follows:

| | Three Months Ended June 30, | | Six Months Ended June 30, | | Total Net SECA Revenues Through June 2006 |
|-------|--------------------------------|---------|------------------------------|---------|---|
| | 2006 | 2005 | 2006 | 2005 | |
| | (in millions) | | | | |
| APCo | \$ - | \$ 10.4 | \$ 11.0 | \$ 19.0 | \$ 55.5 |
| CSPCo | - | 5.3 | 6.5 | 9.6 | 30.8 |
| I&M | - | 5.9 | 6.7 | 10.8 | 32.7 |
| KPCo | - | 2.5 | 2.7 | 4.5 | 13.2 |
| OPCo | - | 7.4 | 8.6 | 13.5 | 42.2 |

Approximately \$19 million of these recorded SECA revenues billed by PJM were never collected. The AEP East companies filed a motion with the FERC to force these parties to pay their SECA billings. The FERC has not yet acted on the motion.

Intervenor in the SECA proceeding are objecting to the SECA rates and the method of determining those rates. SECA hearings were held in May 2006 to determine whether any of the SECA revenues should be refunded. Management negotiated settlements with certain major intervenors and is engaged in settlement talks with other intervenors. The AEP East companies provided for net refunds, most of which were recorded in the second quarter of 2006 as shown in the following table.

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|-------|--------------------------------|--------|------------------------------|--------|
| | 2006 | 2005 | 2006 | 2005 |
| APCo | \$ 5.7 | \$ 0.4 | \$ 6.1 | \$ 0.4 |
| CSPCo | 3.2 | 0.2 | 3.4 | 0.2 |
| I&M | 3.4 | 0.2 | 3.6 | 0.2 |
| KPCo | 1.4 | 0.1 | 1.4 | 0.1 |
| OPCo | 4.3 | 0.3 | 4.6 | 0.3 |

Unless all intervenor claims are fully settled, the ALJ is expected to issue an initial decision in the third quarter of 2006. At this time, management is unable to determine whether the outcome of the FERC's SECA rate proceeding and AEP's filed motion to force payment of unpaid invoices will have any additional adverse impact on the AEP East companies' future results of operations and cash flows.

AEP East Transmission Revenue Requirement and Rates

In December 2005, the FERC approved an uncontested settlement allowing increases in the AEP East companies' wholesale transmission OATT rates in three steps: first, beginning retroactively on November 1, 2005, second, beginning on April 1, 2006 when the SECA revenues were eliminated and third, beginning on August 1, 2006. Management estimates that this rate increase will increase wholesale transmission revenues by \$22 million in 2006

and \$28 million in 2007.

The Elimination of T&O and SECA Rates and the FERC PJM Regional Transmission Rate Proceeding

In a separate proceeding, at AEP's urging, the FERC instituted an investigation of PJM's zonal rate regime, indicating that the present rate regime may need to be replaced through establishment of regional rates that would compensate AEP, among other transmission owners, for the regional transmission facilities they provide to PJM, which provides service for the benefit of customers throughout PJM. In September 2005, AEP and a nonaffiliated utility (Allegheny Power or AP) jointly filed a regional transmission rate design proposal with the FERC. This filing proposes and supports a new PJM rate regime generally referred to as Highway/Byway.

The following rate regimes have been proposed:

- AEP/AP proposed a Highway/Byway rate design in which:
 - The cost of all transmission facilities in the PJM region operated at 345 kV or higher would be included in a "Highway" rate that all load serving entities (LSEs) would pay based on peak demand.
 - The cost of transmission facilities operating at lower voltages would be collected in the zones where those costs are presently charged under PJM's existing rate design.
- In a competing Highway/Byway proposal, a group of LSEs proposed rates that would include 500 kV and higher existing facilities and some facilities at lower voltages in the Highway rate.
- Another proposal uses facilities 200 kV or higher in the Highway rate.
- In January 2006, the FERC staff issued testimony and exhibits supporting a PJM-wide flat rate or "Postage Stamp" type of rate design that would include all transmission facilities.

All of these proposals are being challenged by a majority of transmission owners in the PJM region, who favor continuation of the PJM rate design. Hearings were held in April 2006.

The projected impact on the AEP East companies' revenues by plan follows:

- The AEP/AP Highway/Byway rate design would result in incremental net revenues of approximately \$125 million per year for the transmission-owning AEP East companies.
- The competing Highway/Byway proposals filed by others would also produce incremental net revenues to the AEP East transmission-owning companies, but at a much lower level.
- The staff rate design would produce slightly more net revenue for AEP than the original AEP/AP proposal, when fully effective; however, the staff recommended a phase-in plan that would take an estimated six years to complete.

From the elimination of through and out (T&O) rates in December 2004 through the expiration of SECA rates on March 31, 2006, SECA transition rates failed to fully compensate the AEP East companies for their lost T&O revenues. Effective with the expiration of the SECA transition rates on March 31, 2006, the increase in the AEP East zonal transmission rates applicable to AEP's internal load and wholesale transmission customers in AEP's zone was not sufficient to replace the prior T&O service or temporary SECA transition rate revenues; however, a favorable outcome in the PJM regional transmission rate proceeding, made retroactive to April 1, 2006 could mitigate a large portion of the expected shortfall. Full mitigation of the effects of eliminated T&O revenues and the less favorable terminated SECA revenues will require cost recovery through state retail rate proceedings pending any resolution that may result from the above FERC regional transmission rate proceeding. The status of such state retail rate proceedings is as follows:

- In Kentucky, KPCo settled a rate case, which provided for the recovery of its share of the transmission revenue reduction starting March 30, 2006.

- In Ohio, CSPCo and OPCo are recovering the FERC approved OATT, which reflects their share of the full transmission revenue requirement retroactive to April 1, 2006 under a May 2006 PUCO order.
- In West Virginia, APCo settled a rate case, which provided for the recovery of its share of the T&O/SECA transmission revenue reductions beginning July 28, 2006.
- In Virginia, APCo filed a request for revised rates, which includes recovery of its share of the T&O/SECA transmission revenue reductions starting October 2, 2006, subject to refund.
- In Indiana, I&M is precluded by a rate cap from raising its rates until July 1, 2007.

In July 2006, the ALJ who heard the regional rate case for the FERC rendered an initial decision recommending that the current transmission rates in PJM are unjust and unreasonable and should be revised effective April 1, 2006. The ALJ recommended a regional rate design similar to the staff's favorable "Postage Stamp" rate design discussed above. If approved, the new rates should result in recovery of a significant portion of the revenues lost due to elimination of T&O and SECA rates. However, the ALJ recommended a phase-in of the new "Postage Stamp" rates, which limits increases of any one pricing zone to 10% per year. AEP estimates the phase-in may occur over a six-year period. Once approved, the impacts of the new PJM rate design will flow directly to wholesale customers and to retail customers in Ohio and West Virginia. In Indiana, Kentucky, Michigan, Tennessee and Virginia, the additional transmission revenues can be expected to reduce retail rates in future rate proceedings.

Management is unable to predict whether the FERC will approve either the ALJ's decision or another regional rate design. Parties to the proceeding have a right to file exceptions to both the ALJ initial decision and replies to the exceptions. AEP expects to file exceptions to certain aspects of the ALJ initial decision. The FERC will issue an order after considering the ALJ decision and subsequent filings.

Future results of operations, cash flows and financial condition would be adversely affected if the approved FERC transmission rates are not sufficient to replace the lost T&O/SECA revenues and the resultant increase in the AEP East companies' unrecovered transmission costs are not fully recovered in retail rates.

Allocation Agreement between AEP East companies and AEP West companies and CSW Operating Agreements - Affecting the AEP East companies and AEP West companies

The SIA provides, among other things, for the methodology of sharing trading and marketing margins between the AEP East companies and AEP West companies. In March 2006, the FERC approved AEP's proposed methodology to be used effective April 1, 2006 and beyond. The approved allocation methodology is based upon the location of the specific trading and marketing activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to the benefit of PSO and SWEPCo. Previously, the SIA allocation provided for a different method of sharing all such margins between both AEP East companies and AEP West companies. In February 2006, AEP filed with the FERC to remove TCC and TNC from the SIA and CSW Operating Agreement because those companies are in the final stages of exiting the generation business and have already ceased serving retail load. The FERC approved the removal of TCC and TNC from the SIA and CSW Operating Agreement effective May 1, 2006. The impact on future results of operations and cash flows will depend upon the level of future margins by region and the status of cost recovery mechanisms by state.

4. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING

The Customer Choice and Industry Restructuring note in the 2005 Annual Report should be read in conjunction with this report to gain a complete understanding of material customer choice and industry restructuring matters without significant changes since year-end. The following paragraphs discuss significant current events related to customer choice and industry restructuring in those states and updates the 2005 Annual Report.

TEXAS RESTRUCTURING - Affecting TCC, TNC and SWEPCo

The PUCT issued an order in TCC's True-up Proceeding in February 2006, which determined that TCC's true-up regulatory asset was \$1.475 billion including carrying costs through September 2005. In December 2005, TCC adjusted its recorded net true-up regulatory asset to comply with the order. The PUCT issued an order on rehearing in April 2006, which made minor changes to, but otherwise affirmed, the February 2006 order. TCC appealed, seeking additional recovery consistent with the Texas Restructuring Legislation and related rules. Other parties appealed the PUCT's true-up order claiming it permits TCC to over-recover stranded generation costs and other true-up items.

TCC Securitization Proceeding

TCC filed an application in March 2006 requesting to recover through securitization \$1.8 billion of net stranded generation plant costs and related carrying costs through August 31, 2006. The \$1.8 billion did not include TCC's other true-up items, which total \$475 million and which would be refunded through a CTC over a period to be determined by the PUCT. See "CTC Proceeding for Other True-up Items" section of this note. Intervenors and the PUCT staff filed testimony regarding TCC's securitization request in April 2006. In May 2006, TCC filed a letter with the PUCT reducing its request by \$6 million and reduced the recorded net recoverable asset by that amount. In May 2006, TCC and the other parties filed a settlement with the PUCT, which further reduced the securitizable amount by \$77 million and settled several issues that would have delayed the sale of the securitization bonds. The PUCT approved the settlement in June 2006 authorizing \$1.697 billion including carrying costs through August 31, 2006, the assumed securitization date, plus estimated issuance costs of \$23 million, for a total of \$1.72 billion. TCC anticipates issuing the securitization bonds by the end of the third quarter of 2006.

Consistent with certain prior securitization determinations, the PUCT issued a specific order in the securitization proceeding that calculated a \$315 million cost-of-money benefit (\$310 million through June 30, 2006 of which \$70 million relates to the recorded benefit prior to June 30, 2006 and \$240 million relates to the unrecorded benefit subsequent to June 30, 2006) for ADFIT resulting from the securitization request. The PUCT included the \$315 million in the CTC refund of \$475 million. In June, TCC transferred the effects of the ADFIT on recorded carrying cost from the securitizable asset to the CTC refund, thereby increasing the carrying costs identified to the securitizable assets in the table below.

TCC performed a probability of recovery impairment test on its net true-up regulatory asset taking into account the treatment ordered by the PUCT and determined that the projected cash flows from the securitization less the proposed CTC refund would be more than sufficient to recover TCC's recorded net true-up regulatory asset. As a result, no additional impairment was recorded for the approved reduction in the amount to be securitized. However, the \$77 million agreed upon reduction in the securitizable amount will have a negative impact on future earnings.

The differences between the securitization amount ordered by the PUCT of \$1.7 billion and the recorded securitizable true-up regulatory asset of \$1.5 billion at June 30, 2006 are detailed in the table below:

| | (in millions) |
|---|------------------|
| Stranded Generation Plant Costs | \$ 974 |
| Net Generation-related Regulatory Asset | 249 |
| Excess Earnings | (49) |
| Recorded Net Stranded Generation Plant Costs | 1,174 |
| Recorded Debt Carrying Costs on Net Stranded Generation Plant Costs | 375 |
| Recorded Securitizable True-up Regulatory Asset | 1,549 |
| Unrecorded But Recoverable Equity Carrying Costs | 217 |
| Unrecorded Estimated July 2006 - August 2006 Debt Carrying Costs | 17 |

| | |
|--|----------|
| Unrecorded Excess Earnings, Related Carrying Costs and Other | 52 |
| Settlement Reduction | (77) |
| Reduction for the ADITC and EDFIT Benefits | (61) |
| Approved Securitizable Amount | 1,697 |
| Unrecorded Securitization Bond Issuance Costs | 23 |
| Amount to be Securitized | \$ 1,720 |

Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes

In TCC's true-up and securitization orders, the PUCT reduced net stranded generation plant costs and the amount to be securitized by \$51 million related to the present value of ADITC and by \$10 million related to EDFIT associated with TCC's generating assets. TCC testified that the sharing of these tax benefits with customers might be a violation of the Internal Revenue Code's normalization provisions.

TCC filed a request for a private letter ruling from the IRS in June 2005 to determine whether the PUCT's action would result in a normalization violation. The IRS issued its private letter ruling on May 9, 2006 and decided against the PUCT treatment and determined the PUCT's flowthrough to customers of the ADITC and EDFIT benefits would result in a normalization violation. TCC informed the PUCT on May 10, 2006 of the adverse ruling, however, the PUCT did not change its order on rehearing. TCC filed an appeal as noted earlier. As discussed in the "CTC Proceeding for Other True-up Items" section of this note, TCC proposed to defer the refunding of the ADITC and EDFIT in the securitization through its CTC filing until this normalization issue is resolved upon the IRS issuance of final normalization regulations.

If a normalization violation occurs, it could result in the repayment of TCC's ADITC on all property, including transmission and distribution, which approximates \$105 million as of June 30, 2006 and also a loss of claiming accelerated tax depreciation in future tax returns. Tax counsel has advised management that a normalization violation should not occur until all remedies under law have been exhausted and the tax benefits are returned to ratepayers under a nonappealable order. Management intends to continue its efforts to avoid a normalization violation that would adversely affect TCC's future results of operations and cash flows.

CTC Proceeding for Other True-up Items

In June 2006, TCC filed to implement a negative CTC (a rate reduction) for its net other true-up items over eight years. TCC will incur carrying costs on the net negative other true-up regulatory liability balances until fully refunded. The principal components of the CTC refund liability are an over-recovered fuel balance, the retail clawback and the ADFIT benefit related to TCC's stranded generation cost, offset by a positive wholesale capacity auction true-up regulatory asset balance.

The differences between the components of TCC's Recorded Net Regulatory Liabilities for Other True-up Items as of June 30, 2006 and its CTC gross refund proposal are detailed below:

| | (in millions) |
|--|------------------|
| Wholesale Capacity Auction True-up | \$ 61 |
| Carrying Costs on Wholesale Capacity Auction True-up | 28 |
| Retail Clawback including Carrying Costs | (63) |
| Deferred Over-recovered Fuel Balance | (181) |
| Retrospective ADFIT Benefit | (70) |
| Other | (4) |
| Recorded Net Regulatory Liabilities - Other True-up Items | (229) |
| Unrecorded Prospective ADFIT Benefit | (240) |

| | |
|---|----------|
| Unrecorded Estimated July 2006 - August 2006 Carrying Costs | (6) |
| Gross CTC Refund Proposed | (475) |
| FERC Jurisdictional Fuel Refund Deferral | 16 |
| ADITC and EDFIT Benefit Refund Deferral | 97 |
| Net CTC Refund Proposed, After Deferrals | (362) |
| Rate Case Expense Surcharge | 7 |
| Net Refund Proposed, After Deferrals and Expenses | \$ (355) |

TCC requested that a portion of the refund be deferred, pending the outcome of two contingent federal matters related to the refund of \$16 million of FERC jurisdictional fuel over-recoveries (discussed below) and \$97 million related to potential tax normalization violation matters related to the refund of ADITC and EDFIT benefits discussed above. Although TCC proposed to refund the \$355 million over eight years, certain intervenors have supported accelerated refunds. Management cannot predict the outcome of this filing. If the two contingent federal matters are resolved unfavorably, TCC will refund the \$16 million and the \$97 million plus carrying costs.

Fuel Balance Recoveries

In September 2005, the Federal District Court, Western District of Texas, issued an order precluding the PUCT from enforcing its ruling in the TNC fuel proceeding regarding the PUCT's reallocation of off-system sales margins. TCC has a similar appeal outstanding and believes that the same ruling should result. The favorable Federal District Court order, if upheld on appeal, could result in reductions to the over-recovered fuel principal balances of \$8 million for TNC and \$14 million (\$16 million with carrying costs) for TCC. The PUCT appealed the Federal Court decision to the United States Court of Appeals for the Fifth Circuit. If the PUCT is unsuccessful in the federal court system, it may file a complaint at the FERC to address the allocation issue. TCC is unable to predict if the Federal District Court's decision will be upheld or whether the PUCT will file a complaint at the FERC. Pending further clarification, TCC and TNC have not reversed their related provisions for fuel over-recovery. If the PUCT or another party were to file a complaint at the FERC and is successful, it could result in an adverse effect on results of operations and cash flows for the AEP East companies as an unfavorable FERC ruling may result in a reallocation of off-system sales margins from AEP East companies to AEP West companies. If the adjustments were applied retroactively, the AEP East companies may be unable to recover the amounts from their customers due to past frozen rates, past inactive fuel clauses and fuel clauses that do not include off-system sales credits.

Carrying Costs on Net True-up Regulatory Assets Impacting Securitization and CTC Proceedings

In TCC's True-up Proceeding, the PUCT allowed TCC to recover carrying costs at an 11.79% overall pretax weighted average cost of capital rate from its unbundled cost of service rate proceeding. The recorded embedded debt component of this carrying cost rate is 8.12%. Through June 30, 2006, TCC recorded \$375 million of debt-related carrying costs on stranded generation plant costs impacting the securitization proceeding. TCC will continue to accrue debt-related carrying cost income until its net true-up regulatory asset is either securitized or fully recovered. Equity carrying costs of \$217 million related to amounts securitized will be recognized in income as collected. The negative carrying cost, both debt and equity, on the net CTC refund is being fully recognized in income, and totals \$52 million through June 2006.

In June 2006, the PUCT adopted a proposed rule that prospectively changes the carrying cost applied to TCC's CTC refund balance. TCC anticipates that the rule change will reduce the carrying cost that TCC will pay on its CTC balance from 11.79% to 7.47%. TCC anticipates that the change will reduce its annual refund by approximately \$8 million. The rule provides for adjustments to the carrying cost rate during subsequent rate case proceedings.

Summary

TCC's recorded securitizable true-up regulatory asset at June 30, 2006 of \$1.5 billion, net of the recorded net regulatory liabilities for other true-up items of \$229 million, reflects the PUCT's orders in TCC's True-up Proceeding and its securitization proceeding. Barring any future disallowances to TCC's net recoverable true-up regulatory asset in any subsequent proceedings or Court rulings, TCC expects to amortize its total securitizable true-up regulatory asset commensurate with recovery over 14 years. If TCC determines as a result of future PUCT orders or appeal court rulings that it is probable TCC cannot recover a portion of its recorded net true-up regulatory asset and is able to estimate the amount of a resultant impairment, TCC would record a provision for such amount which would have an adverse effect on TCC's future results of operations, cash flows and possibly financial condition. TCC is appealing the PUCT orders seeking relief in both state and federal court where it believes the PUCT's rulings are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law. Municipal customers and other intervenors are also appealing the same PUCT orders seeking to further reduce TCC's true-up recoveries.

Although TCC believes it has meritorious arguments, management cannot predict the ultimate outcome of any future proceedings or court appeals. If TCC succeeds in its future appeals, it could have a material favorable effect on TCC's future results of operations, cash flows and financial condition. If municipal customers and other intervenors succeed in their expected appeals, or if the PUCT does not approve TCC's CTC filing as filed and as a result causes a normalization violation, it could have a material adverse effect on TCC's future results of operations, cash flows and financial condition.

Texas Restructuring - SPP

In June 2006, the PUCT adopted a rule delaying customer choice in the SPP area of Texas until no sooner than January 1, 2011. SWEPCo and a small portion of TNC's business operate in SPP. Approximately 3% of TNC's operations are located in the SPP territory, with \$13 million in net assets. A petition was filed in May 2006, requesting approval to transfer Mutual Energy SWEPCO L.P.'s (a subsidiary of AEP C&I Company, LLC) and TNC's customers, facilities and certificated service located in the SPP area to SWEPCo. If this petition is successful, SWEPCo will be the only remaining subsidiary affected by the delay in the SPP area.

OHIO RESTRUCTURING - Affecting CSPCo and OPCo

Rate Stabilization Plans

In January 2005, the PUCO approved Rate Stabilization Plans (RSPs) for CSPCo and OPCo (the Ohio companies). The approved plans in each of 2006, 2007 and 2008 provide, among other things, for CSPCo and OPCo to raise their generation rates by 3% and 7%, respectively, and provide for possible additional annual generation rate increases of up to an average of 4% per year based on supporting the request for additional revenues for specified costs. CSPCo's potential for the additional annual 4% generation rate increases is diminished by approximately three-quarters in 2006 and to a lesser extent in 2007 and 2008 due to the power acquisition rider approved by the PUCO in the Monongahela Power service territory acquisition proceeding and the recovery of pre-construction costs for the IGCC plant (see "IGCC Plant" section of this note below). OPCo's potential for the additional annual 4% generation rate increases is diminished in 2006 by approximately one-quarter and to a lesser extent in 2007 due to the recovery of pre-construction costs for the IGCC plant. The RSPs also provide that the Ohio companies can recover in 2006, 2007 and 2008 estimated 2004 and 2005 environmental carrying costs and PJM-related administrative costs and congestion costs net of financial transmission rights (FTR) revenue related to their obligation as the Provider of Last Resort (POLR) in Ohio's customer choice program. Pretax earnings increased by \$8 million and \$16 million for CSPCo and \$17 million and \$38 million for OPCo in the second quarter and first six months of 2006, respectively, from the RSP rate increases net of amortization of RSP regulatory assets. These increases also included the recognition of equity carrying costs. As of June 30, 2006, CSPCo's and OPCo's unrecognized equity carrying costs from 2004 and 2005, which are recognized over the three-year RSP period, totaled \$5 million and \$31 million, respectively. As of June 30, 2006, the CSPCo's and OPCo's unamortized RSP regulatory assets to be recovered through December 31, 2008 were \$8 million and \$39 million, respectively.

In the second quarter of 2005, the Ohio Consumers' Counsel filed an appeal to the Ohio Supreme Court that challenged the RSPs and also argued that there was no POLR obligation in Ohio and, therefore, CSPCo and OPCo are not entitled to recover any POLR charges. In Dayton Power & Light Company's proceeding, the Ohio Supreme Court concluded that there is a POLR obligation in Ohio, supporting the Ohio companies' position that they can recover a POLR charge. In an appeal concerning the First Energy companies' RSP, the Ohio Supreme Court held that the PUCO's decision to eliminate the offer to customers of a price determined through competitive bids was unlawful. In July 2006, the Ohio Supreme Court vacated the PUCO's RSP order for the Ohio companies, which did not include a competitive bid process, and remanded the case to the PUCO for further proceedings, not inconsistent with the decision in the appeal of the First Energy companies' RSP. The PUCO has not yet acted on the remand of the Ohio companies' RSP orders. In late July 2006, the PUCO acted on the First Energy companies' remand case ordering them to file a plan within 45 days to provide an option for customer participation in the electric market through competitive bids or other reasonable means and also held that the RSP shall remain effective.

In the Ohio companies' case, the Ohio Supreme Court did not address any other issues that had been raised on appeal, stating that its decision does not preclude the Ohio Consumers' Counsel from raising those issues in a future appeal. If the PUCO were to revise the Ohio companies' RSP to include a competitive bid process, the Ohio companies believe that the remainder of the original RSP order should remain in place. However, if on remand the PUCO were to modify other aspects of the RSP order, it could have a material effect on the Ohio companies' future results of operations and cash flows. Pending action by the PUCO on the remand, the Ohio companies' rates and the recovery of the RSP regulatory assets will continue. Management believes that the RSP regulatory assets remain probable of recovery.

IGCC Plant

In March 2005, the Ohio companies 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 proposed cost recovery associated with the IGCC plant in three phases: Phase 1, recovery of \$24 million in pre-construction costs during 2006; Phase 2, recovery of construction-financing costs; and Phase 3, recovery, or refund, in distribution rates of any difference between the market-based standard service offer price for generation and the cost of operating and maintaining the plant, including a return on and return of the projected \$1.2 billion cost of the plant along with fuel, consumables and replacement power costs. The proposed recoveries in Phases 1 and 2 would be applied against the 4% limit on additional generation rate increases the Ohio companies could request in 2006, 2007 and 2008 under their RSPs. As of June 30, 2006, CSPCo and OPCo deferred \$6 million and \$7 million, respectively, of pre-construction IGCC costs.

In April 2006, the PUCO issued an order authorizing the Ohio companies to implement Phase 1 of the cost recovery proposal. The PUCO deferred ruling on Phases 2 and 3 cost recovery until further hearings are held. No date for a further hearing has been set.

In June 2006, the PUCO approved a tariff to recover Phase 1 pre-construction costs over a twelve-month period effective July 1, 2006. In that order the PUCO indicated if the Ohio companies have not commenced continuous construction of the IGCC plant within five years of the order, all charges collected for pre-construction costs, which are assignable to other jurisdictions, must be refunded to Ohio ratepayers with interest.

In June 2006, the Industrial Energy Users - Ohio, an intervenor in the PUCO proceeding, filed a Complaint for Writ of Prohibition at the Ohio Supreme Court to prohibit the use of the PUCO's authorization by the Ohio companies to enforce the collection of the Phase 1 rates and to prohibit the PUCO from further entertaining any increase in rates for the IGCC project. The Ohio companies filed motions to dismiss the complaint with the Ohio Supreme Court. The Ohio companies believe that the PUCO's authorization to begin collection of Phase 1 rates is lawful and that the PUCO has the authority to consider the remaining rate recovery phases associated with the IGCC project. The Ohio companies, however, cannot predict the ultimate outcome of this proceeding or of any appeal of the PUCO's April

2006 order. If the Ohio companies were prohibited from collecting the Phase 1 rates or if the PUCO's order is appealed and found to be unlawful, their future results of operations and cash flows would be adversely affected.

Transmission Rate Filing

In February 2006, in accordance with their RSPs, the Ohio companies filed a request with the PUCO for a two-step increase in their transmission rates. In the filing, the first increase would be effective April 1, 2006 to reflect their share of the loss of SECA revenues and the second increase would be effective August 1, 2006 to recover their share of the cost of the new Wyoming-Jacksons Ferry transmission line. In May 2006, the PUCO issued an order approving the two-step increase in transmission rates with an over/under recovery mechanism effective April 1, 2006. In addition, the order provided for the deferral for future recovery of unrecovered transmission costs resulting from the loss of SECA revenues back to April 1, 2006. The new tariffs were filed with the PUCO and implemented in June 2006. Management anticipates the order will result in increased revenues for CSPCo and OPCo of \$27 million and \$36 million, respectively, in 2006 and \$44 million and \$59 million, respectively, in 2007.

Storm Cost Recovery Filing

In March 2006, the Ohio companies filed an application with the PUCO to implement tariff riders to recover a portion of previously expensed incremental costs of restoring service disrupted by severe winter storms in December 2004 and January 2005. CSPCo and OPCo each requested recovery of approximately \$12 million of such costs. A decision is expected in the third quarter of 2006.

PUCO Staff Report on Service Reliability

In December 2003, the Ohio companies entered into a stipulation agreement regarding distribution service reliability. The stipulation agreement covered the years 2004 and 2005 and, among other features, established certain distribution service reliability measures that the Ohio companies were to meet. In April 2006, the staff of the PUCO submitted a commission-ordered investigative report on the Ohio companies' compliance with the stipulation agreement. In the report, the staff asserted that the Ohio companies failed to fulfill all the terms of the stipulation agreement. The staff recommended various consequences for the PUCO's consideration, including the potential for civil forfeitures, monthly payments until the terms of the stipulation agreement have been met and/or providing credits to customers. The staff also suggested that the PUCO could explore possible improvements in the Ohio companies' management of the reliability process. Finally, the staff recommended that the Ohio companies file, in a companion docket, a comprehensive plan to improve their system reliability. The PUCO ordered the Ohio companies to respond to the staff's recommendations concerning consequences by May 23, 2006.

The Ohio companies responded on a timely basis explaining why they believed that they had substantially met the requirements of the stipulation agreement and offering to spend an additional \$5 million on reliability without recovery. In July 2006, the PUCO directed the Ohio companies to earmark \$10 million for future measures to improve service reliability. The Ohio companies will not be permitted to recover any of that amount from customers. The PUCO further indicated that it will determine where and how the \$10 million will best be applied. In a separate docket, the PUCO directed the Ohio companies to submit a plan to enhance service reliability no later than October 6, 2006. The PUCO indicated that it will set a procedural schedule in the future to consider the Ohio companies' plan.

Customer Choice Deferrals

As provided in stipulation agreements approved by the PUCO in 2000, the Ohio companies defer customer choice implementation costs and related carrying costs in excess of \$20 million each. The agreements provide for the deferral of these costs as regulatory assets until the next distribution base rate cases. Through June 30, 2006, CSPCo and OPCo incurred \$47 million and \$48 million, respectively, of such costs and, accordingly, deferred \$23 million and \$24 million, respectively, of such costs for probable future recovery in distribution rates. CSPCo and OPCo have not

recorded \$4 million each, of equity carrying costs, which are not recognized until collected. Pursuant to the RSPs, recovery of these amounts is subject to PUCO review and is deferred until the next distribution rate filing to change rates after December 31, 2008. The Ohio companies believe that the deferred customer choice implementation costs were prudently incurred to implement customer choice in Ohio and should be recoverable in future distribution rates. If the PUCO determines that any of the deferred costs are unrecoverable, it would have an adverse impact on the Ohio companies' future results of operations and cash flows.

5. COMMITMENTS AND CONTINGENCIES

As discussed in the Commitments and Contingencies note within the 2005 Annual Report, certain Registrant Subsidiaries continue to be involved in various legal matters. The 2005 Annual Report should be read in conjunction with this report in order to understand the other material nuclear and operational matters without significant changes since their disclosure in the 2005 Annual Report. See disclosure below for significant matters and changes in status subsequent to the disclosure made in the 2005 Annual Report.

ENVIRONMENTAL

Federal EPA Complaint and Notice of Violation - Affecting APCo, CSPCo, I&M, and OPCo

The Federal EPA and a number of states alleged that APCo, CSPCo, I&M, OPCo and other nonaffiliated utilities, including the Tennessee Valley Authority, Alabama Power Company, Cincinnati Gas & Electric Company, Ohio Edison Company, Southern Indiana Gas & Electric Company, Illinois Power Company, Tampa Electric Company, Virginia Electric Power Company and Duke Energy, modified certain units at coal-fired generating plants in violation of the NSR requirements of the CAA. The Federal EPA filed its complaints against AEP 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. A bench trial on the liability issues was held during July 2005. Briefing has concluded. In June 2006, the judge stayed the liability decision pending the issuance of a decision by the U.S. Supreme Court in the Duke Energy case. A bench trial on remedy issues, if necessary, is scheduled to begin four months after the U.S. Supreme Court decision is issued.

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 CAA authorizes civil penalties of up to \$27,500 (\$32,500 after March 15, 2004) per day per violation at each generating unit. In 2001, the District Court ruled claims for civil penalties based on activities that occurred more than five years before the filing date of the complaints cannot be imposed. There is no time limit on claims for injunctive relief.

The Federal EPA and eight northeastern states each filed an additional complaint containing additional allegations against the Amos and Conesville plants. APCo and CSPCo filed an answer to the northeastern states' complaint and the Federal EPA's complaint, denying the allegations and stating their defenses. Cases are also pending that could affect CSPCo's share of jointly-owned units at Beckjord (12.5% owned), Zimmer (25.4% owned) and Stuart (26% owned) stations. Similar cases have been filed against other nonaffiliated utilities, including Allegheny Energy, Eastern Kentucky Electric Cooperative, Public Service Enterprise Group, Santee Cooper, Wisconsin Electric Power Company, Mirant, NRG Energy and Niagara Mohawk. Several of these cases were resolved through consent decrees.

Courts have reached different conclusions regarding whether the activities at issue in these cases are routine maintenance, repair, or replacement, and therefore are excluded from NSR. Similarly, courts have reached different results regarding whether the activities at issue increased emissions from the power plants. Appeals on these and other issues were filed in certain appellate courts, including a petition to appeal to the U.S. Supreme Court that was granted

in one case. The Federal EPA issued a final rule that would exclude activities similar to those challenged in these cases from NSR as “routine replacements.” In March 2006, the Court of Appeals for the District of Columbia Circuit issued a decision vacating the rule. The Federal EPA filed a petition for rehearing in that case, which the Court denied. The Federal EPA also recently proposed a rule that would define “emissions increases” in a way that would exclude most of the challenged activities from NSR.

Management is unable to estimate the loss or range of loss related to any contingent liability AEP subsidiaries might have for civil penalties under the CAA proceedings. Management is 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 AEP subsidiaries do not prevail, management believes AEP subsidiaries can recover any capital and operating costs of additional pollution control equipment that may be required through regulated rates and market prices for electricity. If any of the AEP subsidiaries are unable to recover such costs or if material penalties are imposed, it would adversely affect future results of operations, cash flows and possibly financial condition.

Notice of Enforcement and Notice of Citizen Suit - Affecting SWEPCo

In July 2004, two special interest groups, Sierra Club and Public Citizen, issued a notice of intent to commence a citizen suit under the CAA for alleged violations of various permit conditions in permits issued to several SWEPCo generating plants. In March 2005, the special interest groups filed a complaint in Federal District Court for the Eastern District of Texas alleging violations of the CAA at Welsh Plant. SWEPCo filed a response to the complaint in May 2005. Other preliminary motions have been filed and are pending before the Court.

In July 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. In April 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 approximately \$228 thousand against SWEPCo based on alleged violations of certain representations regarding heat input in SWEPCo’s permit application and the violations of certain recordkeeping and reporting requirements. SWEPCo responded to the preliminary report and petition in May 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 reference to a specific heat input value for each Welsh unit.

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, financial condition or cash flows.

Carbon Dioxide Public Nuisance Claims - Affecting AEP East Companies and AEP West Companies

In July 2004, attorneys general from eight states and the corporation counsel for the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. That same day, the Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint in the same court against the same defendants. The actions alleged that CO₂ emissions from the defendant’s power plants constitute a public nuisance under federal common law due to impacts associated with global warming and sought injunctive relief in the form of specific emission reduction commitments from the defendants. In September 2004, the defendants, including AEP and AEPSC, filed a motion to dismiss the lawsuits. In September 2005, the lawsuits were dismissed. The trial court’s dismissal was appealed to the Second Circuit Court of Appeals. Briefing and oral argument have been completed. Management believes the actions are without merit and intends to defend vigorously against the claims.

Ontario Litigation - Affecting CSPCo and OPCo

In June 2005, CSPCo, OPCo and nineteen nonaffiliated utilities were named as defendants in a lawsuit filed in the Superior Court of Justice in Ontario, Canada. AEP has not been served with the lawsuit. The time limit for serving the defendants expired but the case has not been dismissed. The defendants are alleged to own or operate coal-fired electric generating stations in various states that, through negligence in design, management, maintenance and operation, emitted NO_x, SO₂ and particulate matter that harmed the residents of Ontario. The lawsuit seeks class action designation and damages of approximately \$49 billion, with continuing damages of \$4 billion annually. The lawsuit also seeks \$1 billion in punitive damages. Management believes CSPCo and OPCo have meritorious defenses to this action and intend to defend vigorously against it.

OPERATIONAL

Construction - Affecting AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

The Registrant Subsidiaries have substantial construction commitments to support their operations and environmental investments. The following table shows the revised estimated construction expenditures by Registrant Subsidiary for 2006:

| | (in millions) |
|--------|---------------|
| AEGCo | \$ 12 |
| APCo | 928 |
| CSPCo | 319 |
| I&M | 330 |
| KPCo | 54 |
| OPCo | 1,065 |
| PSO | 262 |
| SWEPCo | 315 |
| TCC | 286 |
| TNC | 72 |

Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, and the ability to access capital.

Power Generation Facility and TEM Litigation - Affecting OPCo

AEP has agreements with Juniper Capital L.P. (Juniper) under which Juniper constructed and financed a merchant power generation facility (the Facility) near Plaquemine, Louisiana and leased the Facility to AEP. AEP 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 (approximately 270 MW). OPCo sells the purchased energy at market prices in the Entergy sub-region of the Southeastern Electric Reliability Council market.

OPCo agreed to sell up to approximately 800 MW of energy to 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. AEP alleged that TEM breached the PPA and sought a determination of its rights under the PPA. TEM alleged that the PPA never became enforceable, or alternatively, that the PPA was terminated as the result of AEP's breaches. The corporate parent of TEM (SUEZ-TRACTEBEL S.A.) provided a limited guaranty.

In April 2004, OPCo gave notice to TEM that OPCo (a) was suspending performance of its obligations under the PPA; (b) would seek a declaration from the District Court that the PPA was terminated; and (c) would pursue TEM and SUEZ-TRACTEBEL S.A. under the guaranty, seeking damages and the full termination payment value of the PPA.

A bench trial was conducted in March and April 2005. In August 2005, a federal judge ruled that TEM breached the contract and awarded damages to OPCo of \$123 million plus prejudgment interest. In August 2005, both parties filed motions with the trial court seeking reconsideration of the judgment. OPCo asked the court to modify the judgment to (a) award a termination payment to OPCo under the terms of the PPA; (b) grant OPCo's attorneys' fees; and (c) render judgment against SUEZ-TRACTEBEL S.A. on the guaranty. TEM sought reduction of the damages awarded by the court for replacement electric power products made available by OPCo under the PPA. In January 2006, the trial judge granted AEP's motion for reconsideration concerning TEM's parent guaranty and increased AEP's judgment against TEM to \$173 million plus prejudgment interest, and denied the remaining motions for reconsideration. In March 2006, the trial judge amended the January 2006 order eliminating the additional \$50 million damage award.

In September 2005, TEM posted a letter of credit for \$142 million as security pending appeal of the judgment. Both parties have filed Notices of Appeal with the United States Court of Appeals for the Second Circuit. If the PPA is deemed terminated or found unenforceable by the court ultimately deciding the case, OPCo could be adversely affected to the extent OPCo is unable to find other purchasers of the power with similar contractual terms and to the extent claimed termination value damages are not fully recovered from TEM. Management continues to review all options associated with the Facility investment in order to minimize any long-term negative results.

Coal Transportation Dispute - Affecting PSO, TCC and TNC

PSO, TCC, TNC and two nonaffiliated entities, as joint owners of a generating station, disputed transportation costs for coal received between July 2000 and the present time. The joint plant remitted less than the amount billed and the dispute is pending before the Surface Transportation Board. Based upon a weighted average probability analysis of possible outcomes, PSO, as operator of the plant, recorded provisions for possible loss in 2004 and 2005. The provision was deferred as a regulatory asset under PSO's fuel mechanism and immaterially affected income for TCC and TNC for their respective ownership shares. Management continues to work toward mitigating the disputed amounts to the extent possible.

Coal Transportation Rate Dispute - Affecting PSO

In 1985, the Burlington Northern Railroad Co. (now BNSF) entered into a coal transportation agreement with PSO. The agreement contained a base rate subject to adjustment, a rate floor, a reopener provision and an arbitration provision. In 1992, PSO reopened the pricing provision. The parties failed to reach an agreement and the matter was arbitrated, with the arbitration panel establishing a lowered rate as of July 1, 1992 (the 1992 Rate), and modifying the rate adjustment formula. The decision did not mention the rate floor. From April 1996 through the contract termination in December 2001, the 1992 Rate exceeded the adjusted rate, determined according to the decision. PSO paid the adjusted rate and contended that the panel eliminated the rate floor. BNSF invoiced at the 1992 Rate and contended that the 1992 Rate was the new rate floor. At the end of 1991, PSO terminated the contract by paying a termination fee, as required by the agreement. BNSF contends that the termination fee should have been calculated on the 1992 Rate, not the adjusted rate. BNSF contends that it was underpaid approximately \$9.5 million, including interest.

This matter was submitted to an arbitration board in January 2006. The arbitration board filed its decision in April 2006. The decision stated that BNSF's underpayments claim was denied and that PSO was the prevailing party. In May 2006, PSO filed a request for an order confirming the arbitration award and a request for entry of judgment on the award with the U.S. District Court for the Northern District of Oklahoma. BNSF responded in part stating that the award exceeded the arbitration board's powers, was not final, and could not be confirmed. BNSF additionally claimed that it had until July 24, 2006, to determine what action to take in connection with the award, and that PSO's motion was premature. On July 14, 2006, the U.S. District Court issued an order confirming the arbitration award.

FERC Long-term Contracts - Affecting AEP East Companies and AEP West Companies

In 2002, the FERC held a hearing related to a complaint filed by Nevada Power Company and Sierra Pacific Power Company (the Nevada utilities). The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were "high-priced." The complaint alleged that AEP subsidiaries sold power at unjust and unreasonable prices. In December 2002, a FERC ALJ ruled in AEP's favor and dismissed the complaint filed by the Nevada utilities. In 2001, the Nevada utilities filed complaints asserting that the prices for power supplied under those contracts should be lowered because the market for power was allegedly dysfunctional at the time such contracts were executed. The ALJ rejected the Nevada utilities' complaint, held that the markets for future delivery were not dysfunctional and that the Nevada utilities failed to demonstrate that the public interest required changes be made to the contracts. In June 2003, the FERC issued an order affirming the ALJ's decision. The Nevada utilities' request for a rehearing was denied. The Nevada utilities' appeal of the FERC order is pending before the U.S. Court of Appeals for the Ninth Circuit. Management is unable to predict the outcome of this proceeding and its impact on future results of operations and cash flows.

6. GUARANTEES

There are certain immaterial liabilities recorded for guarantees in accordance with FIN 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties unless specified below.

Letters of Credit

Certain Registrant Subsidiaries have entered into standby letters of credit (LOCs) with third parties. These LOCs cover items such as insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. All of these LOCs were issued in the subsidiaries' ordinary course of business. At June 30, 2006, the maximum future payments of the LOCs include \$1 million and \$4 million for I&M and SWEPCo, respectively, each with a maturity of March 2007.

SWEPCo

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo agreed, under certain conditions, to assume the capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). If Sabine defaults under any of these agreements, SWEPCo's total future maximum payment exposure is approximately \$58 million with maturity dates ranging from July 2006 to February 2012.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation in the amount of approximately \$85 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine. This guarantee ends upon depletion of reserves and final reclamation is

completed. At June 30, 2006, it is estimated the reserves will be depleted in 2029 with final reclamation completed by 2036. The cost for final reclamation during the period 2029 through 2036 is estimated at approximately \$39 million.

Indemnifications and Other Guarantees

Contracts

All of the Registrant Subsidiaries enter into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. Prior to June 30, 2006, TCC entered into sales agreements with a maximum indemnification exposure of \$443 million related to the sale price of its generation assets. See "Texas Plants - South Texas Project" and "Texas Plants - TCC and TNC Generation Assets" sections of Note 10 of the 2005 Annual Report. There are no material liabilities recorded for any indemnifications.

AEP East companies, PSO and SWEPCo are jointly and severally liable for activity conducted by AEPSC on behalf of AEP East companies, PSO and SWEPCo related to power purchase and sale activity conducted pursuant to the System Integration Agreement.

Master Operating Lease

Certain Registrant Subsidiaries lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, the subsidiary has committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At June 30, 2006, the maximum potential loss by subsidiary for these lease agreements, assuming the fair market value of the equipment is zero at the end of the lease term, is as follows:

| Subsidiary | Maximum Potential Loss | (in millions) |
|-------------------|-------------------------------|----------------------|
| APCo | \$ | 7 |
| CSPCo | | 3 |
| I&M | | 5 |
| KPCo | | 2 |
| OPCo | | 7 |
| PSO | | 5 |
| SWEPCo | | 6 |
| TCC | | 6 |
| TNC | | 3 |

7. COMPANY-WIDE STAFFING AND BUDGET REVIEW

The following table shows the severance benefits expense recorded in the second quarter of 2005 (primarily in Maintenance and Other Operation) resulting from a company-wide staffing and budget review, including the allocation of approximately \$15.9 million of severance benefits expense associated with AEPSC employees among the Registrant Subsidiaries. AEGCo has no employees but received allocated expenses.

| Company | Amounts |
|----------------|----------------|
|----------------|----------------|

| | (in millions) |
|--------|------------------|
| AEGCo | \$ 0.2 |
| APCo | 3.9 |
| CSPCo | 2.3 |
| I&M | 4.0 |
| KPCo | 0.7 |
| OPCo | 3.4 |
| PSO | 1.2 |
| SWEPCo | 1.6 |
| TCC | 3.8 |
| TNC | 1.1 |

Remaining accruals, reflected primarily in Current Liabilities - Other, ranged from \$8 thousand to \$1.1 million as of December 31, 2005, and were settled by June 30, 2006. Payments and accrual adjustments recorded during the first and second quarters of 2006 were immaterial.

8. ASSETS HELD FOR SALE

Texas Plants - Oklaunion Power Station - Affecting TCC

In January 2004, TCC signed an agreement to sell its 7.81% share of Oklaunion Power Station for approximately \$43 million (subject to closing adjustments) to Golden Spread Electric Cooperative, Inc. (Golden Spread), subject to a right of first refusal by the Oklahoma Municipal Power Authority and the Public Utilities Board of the City of Brownsfield (the nonaffiliated co-owners). By May 2004, TCC received notice from the nonaffiliated co-owners of the Oklaunion Power Station, announcing their decision to exercise their right of first refusal with terms similar to the original agreement. In June 2004 and September 2004, TCC entered into sales agreements with both of the nonaffiliated co-owners for the sale of TCC's 7.81% ownership of the Oklaunion Power Station. These agreements were challenged in State District Court in Dallas County by Golden Spread. Golden Spread alleges that the Public Utilities Board of the City of Brownsfield exceeded its legal authority and that the Oklahoma Municipal Power Authority did not exercise its right of first refusal in a timely manner. Golden Spread requested that the court declare the nonaffiliated co-owners' exercise of their rights of first refusal void. The court entered a judgment in favor of Golden Spread on October 10, 2005. TCC and the nonaffiliated co-owners filed an appeal to the Court of Appeals for the Fifth District at Dallas. On May 18, 2006, the Court of Appeals for the Fifth District at Dallas reversed the trial court's judgment in favor of Golden Spread and held that the City of Brownsville properly exercised its right of first refusal to acquire TCC's share of Oklaunion. Golden Spread requested a rehearing in the matter, and its petition was denied. TCC cannot predict when these issues will be resolved. TCC does not expect the sale to have a significant effect on its future results of operations. TCC's assets related to the Oklaunion Power Station have been classified as Assets Held for Sale - Texas Generation Plants on TCC's Condensed Consolidated Balance Sheets at June 30, 2006 and December 31, 2005. The plant does not meet the "component-of-an-entity" criteria because it does not have cash flows that can be clearly distinguished operationally. The plant also does not meet the "component-of-an-entity" criteria for financial reporting purposes because it does not operate individually, but rather as a part of the AEP System, which includes all of the generation facilities owned by the Registrant Subsidiaries.

Assets Held for Sale at June 30, 2006 and December 31, 2005 are as follows:

| Texas Plants (TCC) | June 30, 2006 | December 31, 2005 |
|----------------------|------------------|----------------------|
| Assets: | (in millions) | |
| Other Current Assets | \$ 2 | \$ 1 |

| | | | | |
|---|----|----|----|----|
| Property, Plant and Equipment, Net | | 44 | | 43 |
| Total Assets Held for Sale - Texas Generation Plants | \$ | 46 | \$ | 44 |

9. BENEFIT PLANS

APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participate in AEP sponsored U.S. qualified pension plans and nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. In addition, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC participate in other postretirement benefit plans sponsored by AEP to provide medical and death benefits for retired employees.

The following tables provide the components of AEP's net periodic benefit cost for the plans for the three and six months ended June 30, 2006 and 2005:

Three Months Ended June 30, 2006 and 2005:

| | <u>Pension Plans</u> | | <u>Other Postretirement Benefit Plans</u> | |
|---------------------------------------|----------------------|-------|---|-------|
| | 2006 | 2005 | 2006 | 2005 |
| | (in millions) | | | |
| Service Cost | \$ 24 | \$ 23 | \$ 10 | \$ 10 |
| Interest Cost | 57 | 56 | 25 | 26 |
| Expected Return on Plan Assets | (83) | (78) | (23) | (22) |
| Amortization of Transition Obligation | - | - | 7 | 7 |
| Amortization of Net Actuarial Loss | 19 | 14 | 5 | 7 |
| Net Periodic Benefit Cost | \$ 17 | \$ 15 | \$ 24 | \$ 28 |

Six Months Ended June 30, 2006 and 2005:

| | <u>Pension Plans</u> | | <u>Other Postretirement Benefit Plans</u> | |
|---------------------------------------|----------------------|-------|---|-------|
| | 2006 | 2005 | 2006 | 2005 |
| | (in millions) | | | |
| Service Cost | \$ 48 | \$ 46 | \$ 20 | \$ 21 |
| Interest Cost | 114 | 112 | 50 | 53 |
| Expected Return on Plan Assets | (166) | (155) | (46) | (45) |
| Amortization of Transition Obligation | - | - | 14 | 14 |
| Amortization of Net Actuarial Loss | 39 | 27 | 10 | 14 |
| Net Periodic Benefit Cost | \$ 35 | \$ 30 | \$ 48 | \$ 57 |

The following table provides the net periodic benefit cost (credit) for the three and six months ended June 30, 2006 and 2005:

Three Months Ended June 30, 2006 and 2005:

Pension Plans

Other Postretirement Benefit Plans

| | 2006 | | 2005 | | 2006 | | 2005 | |
|--------|----------------|-------|------|-------|------|-------|------|-------|
| | (in thousands) | | | | | | | |
| APCo | \$ | 1,469 | \$ | 1,848 | \$ | 4,489 | \$ | 5,147 |
| CSPCo | | 205 | | 534 | | 1,805 | | 2,123 |
| I&M | | 2,330 | | 2,365 | | 2,953 | | 3,464 |
| KPCo | | 358 | | 376 | | 513 | | 571 |
| OPCo | | 829 | | 1,206 | | 3,396 | | 3,632 |
| PSO | | 979 | | 72 | | 1,588 | | 1,799 |
| SWEPCo | | 1,225 | | 364 | | 1,578 | | 1,765 |
| TCC | | 772 | | (219) | | 1,696 | | 1,935 |
| TNC | | 327 | | 41 | | 715 | | 846 |

Six Months Ended June 30,
2006 and 2005:

| | <u>Pension Plans</u> | | | | <u>Other Postretirement Benefit Plans</u> | | | |
|--------|----------------------|-------|------|-------|---|-------|------|--------|
| | 2006 | | 2005 | | 2006 | | 2005 | |
| | (in thousands) | | | | | | | |
| APCo | \$ | 2,937 | \$ | 3,696 | \$ | 8,978 | \$ | 10,492 |
| CSPCo | | 410 | | 1,068 | | 3,610 | | 4,345 |
| I&M | | 4,661 | | 4,730 | | 5,906 | | 7,095 |
| KPCo | | 716 | | 752 | | 1,026 | | 1,174 |
| OPCo | | 1,655 | | 2,412 | | 6,792 | | 7,459 |
| PSO | | 1,956 | | 144 | | 3,176 | | 3,668 |
| SWEPCo | | 2,450 | | 728 | | 3,156 | | 3,602 |
| TCC | | 1,545 | | (438) | | 3,392 | | 3,943 |
| TNC | | 652 | | 82 | | 1,430 | | 1,723 |

10. INCOME TAXES (Affecting PSO, SWEPCo, TCC and TNC)

In the second quarter of 2006, the Texas state legislature replaced the existing franchise/income tax with a gross margin tax at a 1% rate for electric utilities. Overall, the new law reduces Texas income tax rates and is effective January 1, 2007. The new gross margin tax is income-based for purposes of the application of SFAS 109 "Accounting for Income Taxes." Based on the new law, we reviewed deferred tax liabilities with consideration given to the rate changes and changes to the allowed deductible items with temporary differences. As a result, in the second quarter of 2006 the following adjustments were recorded (in thousands):

| Company | Decrease in SFAS 109 Regulatory Asset, Net | Decrease in State Income Tax Expense | Decrease in Deferred State Income Tax Liabilities |
|---------|--|--------------------------------------|---|
| TCC | \$ 36,315 | \$ - | \$ 36,315 |
| TNC | 4,801 | 1,265 | 6,066 |
| PSO | - | 3,273 | 3,273 |
| SWEPCo | 4,438 | 501 | 4,939 |

11. BUSINESS SEGMENTS

All of AEP's Registrant Subsidiaries have one reportable segment. The one reportable segment is an integrated electricity generation, transmission and distribution business except AEGCo, which is an electricity generation business. All of the Registrant Subsidiaries' other activities are insignificant. The Registrant Subsidiaries' operations are managed on an integrated basis because of the substantial impact of bundled cost-based rates and regulatory oversight on the business process, cost structures and operating results.

12. FINANCING ACTIVITIES

Long-term Debt

Long-term debt and other securities issued, retired and principal payments made during the first six months of 2006 were:

| Company | Type of Debt | Principal Amount (in thousands) | Interest Rate (%) | Due Date |
|-------------------|-------------------------|------------------------------------|----------------------|----------|
| Issuances: | | | | |
| APCo | Pollution Control Bonds | \$ 50,275 | Variable | 2036 |
| APCo | Senior Unsecured Notes | 250,000 | 5.55 | 2011 |
| APCo | Senior Unsecured Notes | 250,000 | 6.375 | 2036 |
| I&M | Pollution Control Bonds | 50,000 | Variable | 2025 |
| OPCo | Pollution Control Bonds | 65,000 | Variable | 2036 |
| OPCo | Senior Unsecured Notes | 350,000 | 6.00 | 2016 |
| SWEPco | Pollution Control Bonds | 81,700 | Variable | 2018 |

In July 2006, AEGCo remarketed its outstanding \$45 million pollution control bonds, resulting in a new interest rate of 4.15%. No proceeds were received related to this remarketing. The principal amount of the pollution control bonds is reflected in Long-term Debt on AEGCo's Condensed Balance Sheet as of June 30, 2006.

| Company | Type of Debt | Principal Amount (in thousands) | Interest Rate (%) | Due Date |
|--|----------------|------------------------------------|----------------------|----------|
| Retirements and Principal Payments: | | | | |
| APCo | First Mortgage | \$ 100,000 | 6.80 | 2006 |

| Bonds | | | | |
|--------|-------------------------|--------|----------|------|
| APCo | Other | 5 | 13.718 | 2026 |
| I&M | Pollution Control Bonds | 50,000 | 6.55 | 2025 |
| Bonds | | | | |
| OPCo | Notes Payable | 2,927 | 6.81 | 2008 |
| OPCo | Notes Payable | 3,250 | 6.27 | 2009 |
| SWEPCo | Notes Payable | 3,394 | 4.47 | 2011 |
| SWEPCo | Notes Payable | 1,500 | Variable | 2008 |
| SWEPCo | Pollution Control Bonds | 81,700 | 6.10 | 2018 |
| TCC | Securitization Bonds | 30,641 | 5.01 | 2010 |

In addition to the transactions reported in the tables above, the following table lists intercompany issuances and retirements of debt due to AEP:

| Company | Type of Debt | Principal Amount (in thousands) | Interest Rate (%) | Due Date |
|---------------------|---------------|------------------------------------|----------------------|----------|
| Issuances: | | | | |
| TCC | Notes Payable | \$ 125,000 | 5.14 | 2007 |
| Retirements: | | | | |
| KPCo | Notes Payable | 40,000 | 6.501 | 2006 |
| OPCo | Notes Payable | 200,000 | 3.32 | 2006 |
| PSO | Notes Payable | 50,000 | 3.35 | 2006 |

In August 2006, an affiliate issued TCC a 5.86%, \$70 million note due August 16, 2007.

Lines of Credit - AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. The AEP System corporate borrowing program operates in accordance with the terms and conditions approved in a regulatory order. The Utility Money Pool participants' money pool activity and corresponding authorized limits for the six months ended June 30, 2006 are described in the following table:

Six Months Ended June 30, 2006:

Company

| | Maximum Borrowings from Utility Money Pool | Maximum Loans to Utility Money Pool | Average Borrowings from Utility Money Pool | Average Loans to Utility Money Pool | Loans (Borrowings) to/from Utility Money Pool as of June 30, 2006 | Authorized Short-Term Borrowing Limit |
|----------------|---|--|---|--|--|--|
| (in thousands) | | | | | | |
| AEGCo | \$ 58,209 | \$ 2,247 | \$ 19,213 | \$ 2,247 | \$ (36,989) | \$ 125,000 |
| APCo | 283,872 | 314,064 | 200,248 | 252,627 | 218,702 | 600,000 |
| CSPCo | 48,337 | 24,779 | 15,133 | 7,719 | 12,616 | 350,000 |
| I&M | 128,071 | - | 71,724 | - | (57,749) | 500,000 |
| KPCo | 46,156 | 11,993 | 20,478 | 4,384 | (36,991) | 200,000 |
| OPCo | 351,302 | 36,787 | 127,955 | 15,886 | 36,787 | 600,000 |
| PSO | 167,456 | - | 90,702 | - | (139,831) | 300,000 |
| SWEPCo | 127,291 | - | 59,388 | - | (93,083) | 350,000 |
| TCC | 117,429 | 49,193 | 46,872 | 27,343 | (27,926) | 600,000 |
| TNC | 14,513 | 34,574 | 4,571 | 8,680 | (6,005) | 250,000 |

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool for the six months ended June 30, 2006 and 2005 were 5.39% and 4.19% and 3.43% and 1.63%, respectively. The average interest rates for funds borrowed from and loaned to the Utility Money Pool for the six months ended June 30, 2006 and 2005 are summarized for all Registrant Subsidiaries in the following table:

| Company | Average Interest Rate for Funds Borrowed from the Utility Money Pool for Six Months Ended June 30, 2006 | Average Interest Rate for Funds Borrowed from the Utility Money Pool for Six Months Ended June 30, 2005 | Average Interest Rate for Funds Loaned to the Utility Money Pool for Six Months Ended June 30, 2006 | Average Interest Rate for Funds Loaned to the Utility Money Pool for Six Months Ended June 30, 2005 |
|-----------------|--|--|--|--|
| (in percentage) | | | | |
| AEGCo | 4.78 | 2.40 | 5.11 | 3.14 |
| APCo | 4.62 | 2.65 | 5.05 | 2.69 |
| CSPCo | 4.73 | - | 4.91 | 2.44 |
| I&M | 4.76 | 2.96 | - | 2.12 |
| KPCo | 4.98 | 2.96 | 4.97 | 2.42 |
| OPCo | 4.86 | 3.32 | 5.30 | 2.39 |
| PSO | 4.91 | 2.50 | - | 3.19 |
| SWEPCo | 4.92 | 3.21 | - | 2.54 |
| TCC | 4.64 | 2.91 | 4.74 | 2.12 |
| TNC | 4.81 | - | 4.62 | 2.65 |

COMBINED MANAGEMENT'S DISCUSSION AND ANALYSIS OF REGISTRANT SUBSIDIARIES

The following is a combined presentation of certain components of the management's discussion and analysis of Registrant Subsidiaries. The information in this section completes the information necessary for management's discussion and analysis of financial condition and results of operations and is meant to be read with (i) Management's Financial Discussion and Analysis, (ii) financial statements, and (iii) footnotes of each individual registrant. The Combined Management's Discussion and Analysis of Registrants Subsidiaries section of the 2005 Annual Report should be read in conjunction with this report.

Construction Expenditures

The Registrant Subsidiaries have substantial construction commitments to support their operations and environmental investments. The following table shows the revised estimated construction expenditures by Registrant Subsidiary for 2006:

| | (in millions) |
|--------|---------------|
| AEGCo | \$ 12 |
| APCo | 928 |
| CSPCo | 319 |
| I&M | 330 |
| KPCo | 54 |
| OPCo | 1,065 |
| PSO | 262 |
| SWEPCo | 315 |
| TCC | 286 |
| TNC | 72 |

Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends and the ability to access capital.

Environmental Matters

The Registrant Subsidiaries have committed to substantial capital investments and additional operational costs to comply with new environmental control requirements. The sources of these requirements include:

- Requirements under the CAA to reduce emissions of SO₂, NO_x, particulate matter (PM), and mercury from fossil fuel-fired power plants;
- Requirements under the Clean Water Act (CWA) to reduce the impacts of water intake structures on aquatic species at certain power plants; and
- Possible future requirements to reduce carbon dioxide (CO₂) emissions to address concerns about global climate change.

In addition, the Registrant Subsidiaries are engaged in litigation with respect to certain environmental matters, have been notified of potential responsibility for the clean-up of contaminated sites, and incur costs for disposal of spent nuclear fuel and future decommissioning of I&M's nuclear units.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality and control mobile and stationary sources of air emissions. The major CAA programs affecting power plants are briefly described below. Many of these programs are implemented and administered by the states, which can impose additional or more stringent requirements.

National Ambient Air Quality Standards: The CAA requires the Federal EPA to periodically review the available scientific data for six criteria pollutants and establish a concentration level in the ambient air for those substances that is adequate to protect the public health and welfare with an extra margin for safety. These concentration levels are known as "national ambient air quality standards" or NAAQS.

Each state identifies those areas within its boundaries that meet the NAAQS (attainment areas) and those that do not (nonattainment areas). Each state must then develop a state implementation plan (SIP) to bring nonattainment areas into compliance with the NAAQS and maintain good air quality in attainment areas. All SIPs are then submitted to the Federal EPA for approval. If a state fails to develop adequate plans, the Federal EPA must develop and implement a plan. In addition, as the Federal EPA reviews the NAAQS, the attainment status of areas can change, and states may be required to develop new SIPs. The Federal EPA recently proposed a new PM NAAQS and is conducting periodic reviews for additional criteria pollutants.

In 1997, the Federal EPA established new NAAQS that required further reductions in SO₂ and NO_x emissions. In 2005, the Federal EPA issued a final model federal rule, the Clean Air Interstate Rule (CAIR), that assists states developing new SIPs to meet the new NAAQS. CAIR reduces regional emissions of SO₂ and NO_x from power plants in the Eastern U.S. (29 states and the District of Columbia). CAIR requires power plants within these states to reduce emissions of SO₂ by 50 percent by 2010, and by 65 percent by 2015. NO_x emissions will be subject to additional limits beginning in 2009 and will be reduced by a total of 70 percent from current levels by 2015. Reductions of both SO₂ and NO_x would be achieved through a cap-and-trade program. The Federal EPA affirmed certain aspects of the final CAIR after considering petitions for reconsideration. The rule has been challenged in the courts. States must develop and submit SIPs to implement CAIR by November 2006. Nearly all of the states in which the Registrant Subsidiaries' power plants are located will be covered by CAIR. Oklahoma is not affected, while Texas and Arkansas will be covered only by certain parts of CAIR. A SIP that complies with CAIR will also establish compliance with other CAA requirements, including certain visibility goals.

Hazardous Air Pollutants: As a result of the 1990 Amendments to the CAA, the Federal EPA investigated hazardous air pollutant (HAP) emissions from the electric utility sector and submitted a report to Congress, identifying mercury emissions from coal-fired power plants as warranting further study. In March 2005, the Federal EPA issued a final Clean Air Mercury Rule (CAMR) setting mercury standards for new coal-fired power plants and requiring all states to issue new SIPs including mercury requirements for existing coal-fired power plants. The Federal EPA issued a model federal rule based on a cap-and-trade program for mercury emissions from existing coal-fired power plants that would reduce mercury emissions to 38 tons per year from all existing plants in 2010, and to 15 tons per year in 2018. The national cap of 38 tons per year in 2010 is intended to reflect the level of reduction in mercury emissions that will be achieved as a result of installing controls to reduce SO₂ and NO_x emissions in order to comply with CAIR. The Federal EPA affirmed the final CAMR after reconsidering certain aspects of the rule and the rule has been challenged in the courts. States must develop and submit their SIPs to implement CAMR by November 2006.

The Acid Rain Program: The 1990 Amendments to the CAA included a cap-and-trade emission reduction program for SO₂ emissions from power plants, implemented in two phases. By 2000, the program established a nationwide cap on power plant SO₂ emissions of 8.9 million tons per year. The 1990 Amendments also contained requirements for power plants to reduce NO_x emissions through the use of available combustion controls.

The success of the SO₂ cap-and-trade program encouraged the Federal EPA and the states to use it as a model for other emission reduction programs, including CAIR and CAMR. The Registrant Subsidiaries meet their obligations under the Acid Rain Program through the installation of controls, use of alternate fuels, and participation in the emissions allowance markets. CAIR uses the SO₂ allowances originally allocated through the Acid Rain Program as the basis for its SO₂ cap-and-trade system.

Regional Haze: The CAA also establishes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing impairment and remedying any existing impairment of visibility in these areas. This is commonly called the “Regional Haze” program. In June 2005, the Federal EPA issued its final Clean Air Visibility Rule (CAVR), detailing how the CAA’s best available retrofit technology (BART) requirements will be applied to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. The final rule contains a demonstration that for power plants subject to CAIR, CAIR will result in more visibility improvements than BART would provide. Thus, states are allowed to substitute CAIR requirements in their Regional Haze SIPs for controls that would otherwise be required by BART. For BART-eligible facilities located in states not subject to CAIR requirements for SO₂ and NO_x, some additional controls will be required. The final rule has been challenged in the courts.

Estimated Air Quality Environmental Investments

As discussed in the 2005 Annual Report, the CAIR and CAMR programs described above will require significant additional investments, some of which are estimable. However, many of the rules described above have been challenged in the courts and have not yet been incorporated into SIPs. As a result, these rules may be further modified. Management’s estimates, disclosed in the 2005 Annual Report, are subject to significant uncertainties, and will be affected by any changes in the outcome of several interrelated variables and assumptions, including: the timing of implementation, required levels of reductions, methods for allocation of allowances and selected compliance alternatives. In short, management cannot estimate compliance costs with certainty.

The Registrant Subsidiaries will seek recovery of expenditures for pollution control technologies, replacement or additional generation and associated operating costs from customers through regulated rates (in regulated jurisdictions). The Registrant Subsidiaries should be able to recover these expenditures through market prices in deregulated jurisdictions. If not, those costs could adversely affect future results of operations, cash flows and possibly financial condition.

Potential Regulation of CO₂ Emissions

At the Third Conference of the Parties to the United Nations Framework Convention on Climate Change held in Kyoto, Japan in December 1997, more than 160 countries, including the U.S., negotiated a treaty requiring legally-binding reductions in emissions of greenhouse gases, chiefly CO₂, which many scientists believe are contributing to global climate change. The U.S. signed the Kyoto Protocol in November 1998, but the treaty was not submitted to the Senate for its advice and consent. In March 2001, President Bush announced his opposition to the treaty. During 2004, enough countries ratified the treaty for it to become enforceable against the ratifying countries in February 2005. Several bills have been introduced in Congress seeking regulation of greenhouse gas emissions, including CO₂ emissions from power plants, but none have passed either house of Congress.

The Federal EPA stated that it does not have authority under the CAA to regulate greenhouse gas emissions that may affect global climate trends. This decision was challenged in the courts and upheld by an appellate court. The U.S. Supreme Court will review the appellate decision. While mandatory requirements to reduce CO₂ emissions at our power plants do not appear to be imminent, we participate in a number of voluntary programs to monitor, mitigate, and reduce greenhouse gas emissions.

Environmental Litigation

New Source Review (NSR) Litigation: In 1999, the Federal EPA and a number of states filed complaints alleging that APCo, CSPCo, I&M, and OPCo modified certain units at coal-fired generating plants in violation of the NSR requirements of the CAA. A separate lawsuit, initiated by certain environmental intervenor groups, has been consolidated with the Federal EPA case. Several similar complaints were filed in 1999 and 2000 against other nonaffiliated utilities, including Allegheny Energy, Eastern Kentucky Electric Cooperative, Public Service Enterprise Group, Santee Cooper, Wisconsin Electric Power Company, Mirant, NRG Energy and Niagara Mohawk. Several of these cases were resolved through consent decrees. The alleged modifications at our power plants occurred over a 20-year period. A bench trial on the liability issues was held during July 2005. Briefing has concluded. In June 2006, the judge stayed the liability decision pending the issuance of a decision by the U.S. Supreme Court in the Duke Energy case. A bench trial on remedy issues, if necessary, is scheduled to begin four months after the U.S. Supreme Court decision is issued.

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.

Courts that considered whether the activities at issue in these cases are routine maintenance, repair, or replacement, and therefore are excluded from NSR, reached different conclusions. Similarly, courts that considered whether the activities at issue increased emissions from the power plants reached different results. Appeals on these and other issues have been filed in certain appellate courts, including a petition to appeal to the U.S. Supreme Court that was granted in one case. The Federal EPA issued a final rule that would exclude activities similar to those challenged in these cases from NSR as "routine replacements." In March 2006, the Court of Appeals for the District of Columbia Circuit issued a decision vacating the rule. The Federal EPA filed a petition for rehearing in that case, which the Court denied. The Federal EPA also recently proposed a rule that would define "emissions increases" in a way that would exclude most of the challenged activities from NSR.

Management is unable to estimate the loss or range of loss related to any contingent liability the Registrant Subsidiaries might have for civil penalties under the CAA proceedings. Management is 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 the Registrant Subsidiaries do not prevail, management believes the Registrant Subsidiaries can recover any capital and operating costs of additional pollution control equipment that may be required through regulated rates and market prices for electricity. If the Registrant Subsidiaries are unable to recover such costs or if material penalties are imposed, it would adversely affect future results of operations, cash flows and possibly financial condition.

Other Environmental Concerns

Management performs environmental reviews and audits on a regular basis for the purpose of identifying, evaluating and addressing environmental concerns and issues. In addition to the matters discussed above, the Registrant Subsidiaries are managing other environmental concerns, which are not believed to be material or potentially material at this time. If they become significant or if any new matters arise that could be material, they could have a material adverse effect on results of operations, cash flows and possibly financial condition.

Adoption of New Accounting Pronouncements

Beginning in 2006, the Registrant Subsidiaries adopted SFAS No. 123 (revised 2004) Share-Based Payment, on a modified prospective basis, resulting in an insignificant favorable cumulative effect of a change in accounting principle. Including stock-based compensation expense related to employee stock options and other share based

awards, did not materially affect the Registrant Subsidiaries' quarter-over-quarter and year-to-date net income (loss). See Note 2 - New Accounting Pronouncements in the Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries for further discussion.

CONTROLS AND PROCEDURES

During the second quarter of 2006, management, including the principal executive officer and principal financial officer of each of AEP, AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC (collectively, the Registrants), evaluated the Registrants' disclosure controls and procedures. Disclosure controls and procedures are defined as controls and other procedures of the Registrants that are designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act is accumulated and communicated to the Registrants' management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

As of June 30, 2006, these officers concluded that the disclosure controls and procedures in place are effective and provide reasonable assurance that the disclosure controls and procedures accomplished their objectives. The Registrants continually strive to improve their disclosure controls and procedures to enhance the quality of their financial reporting and to maintain dynamic systems that change as events warrant.

There was no change in the Registrants' internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the second quarter of 2006 that materially affected, or is reasonably likely to materially affect, the Registrants' internal controls over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

For a discussion of material legal proceedings, see Note 5, *Commitments and Contingencies*, incorporated herein by reference.

Item 1A. Risk Factors

Our Annual Report on Form 10-K for the year ended December 31, 2005 includes a detailed discussion of our risk factors. The information presented below amends and restates in their entirety certain of those risk factors that have been updated and should be read in conjunction with the risk factors and information disclosed in our 2005 Annual Report on Form 10-K.

General Risks of Our Regulated Operations

Our requests for rate recovery of additional costs may not be approved in Virginia. *(Applies to AEP and APCo.)*

On July 1, 2005, APCo filed a request with the Virginia SCC seeking approval for the recovery of \$62 million in incremental costs through June 30, 2006. The \$62 million request included incurred and projected costs of environmental controls, transmission costs (including line construction) and other system reliability work (all referred to as "E&R"). In October 2005, the Virginia SCC ruled that it does not have the authority to approve the recovery of projected costs. In November 2005, APCo filed supplemental testimony in which it updated the actual costs through September 2005 and reduced its requested recovery to \$21 million. The staff of the Virginia SCC made filings to dismiss the transmission system reliability costs from consideration for recovery, arguing that the FERC, and not the Virginia SCC, has jurisdiction over the unbundled transmission component of APCo's retail rates. Through June 30, 2006, APCo deferred \$37 million of recorded costs that are subject to this proceeding. The staff of the Virginia SCC originally proposed that APCo be allowed to increase its electric rates at a going forward level of \$20 million to recover current, rather than past, incremental E&R costs. Hearings concluded in March 2006. At the hearings, the staff amended its testimony to recommend a \$24 million increase in APCo's ongoing rates. If the Virginia SCC adopts the staff's recommendation or denies recovery of any of APCo's deferred costs, it would adversely impact future results of operations and cash flows.

In addition, APCo filed a request with the Virginia SCC in May 2006 seeking an increase in base rates of \$225 million to recover increasing costs, including a return on equity of 11.5%. APCo also requested to apply off-system sales margins (currently credited to customers through base rates) to the fuel factor where they can be adjusted annually. APCo also requested to retain a portion of the off-system sales margins. This proposed off-system sales fuel rate credit is projected to be \$27 million annually. It would partially offset the \$225 million requested increase in base rates for a net increase in revenues of \$198 million. In May 2006, the Virginia SCC issued an order placing the full requested base rate increase into effect as of October 2, 2006, subject to refund. Hearings are scheduled to begin in November 2006. We are unable to predict the ultimate effect of this filing on future revenues, cash flows and financial condition.

Our request for rate recovery of additional costs may not be approved in West Virginia. *(Applies to AEP and APCo.)*

The West Virginia Public Service Commission approved our pending West Virginia base rate case settlement agreement in July 2006. Therefore, this risk factor is no longer applicable.

Our request for rate recovery of additional costs may not be approved in Kentucky. *(Applies to AEP and KPCo.)*

The Kentucky Public Service Commission approved our pending Kentucky base rate case settlement agreement in March 2006. Therefore, this risk factor is no longer applicable.

The rates that SWEPCo may charge its customers may be reduced. (Applies to SWEPCo)

In October 2005, the staff of the PUCT reported results of its review of SWEPCo's year-end 2004 earnings. Based upon the staff's adjustments to the information submitted by SWEPCo, the report indicates that SWEPCo is receiving excess revenues of approximately \$15 million. The staff engaged SWEPCo in discussions to reconcile the earnings calculation and consider possible ways to address the results. After those discussions, the PUCT staff informed SWEPCo in April 2006 that they would not pursue the matter further.

Separately, at the time of the CSW merger, SWEPCo agreed to file with the Louisiana Public Service Commission (LPSC) detailed financial information typically utilized in a revenue requirement filing on a periodic basis in order to demonstrate the lack of adverse impact from the merger. The first such filing was in October 2002 and the second was in April 2004. While both filings indicated SWEPCo's rates should not be reduced, direct testimony filed by the LPSC staff's consultants recommends a \$15 million reduction in SWEPCo's Louisiana jurisdictional base rates. In April 2006, the LPSC and SWEPCo agreed to update the financial information based on a 2005 test year. SWEPCo filed financial review schedules in May 2006 showing a return on equity of 9.44%. In July 2006, the LPSC staff's consultants filed direct testimony recommending a base rate reduction in the range of \$12 million to \$20 million for SWEPCo's Louisiana jurisdiction customers, which included a 10% return on equity. The recommended reduction range is subject to SWEPCo validating certain on-going operations and maintenance expense levels and the recommended base rate reduction does not include the impact of a proposed consolidated federal income tax adjustment, which would increase the proposed rate reduction. Hearings are scheduled for October 2006. A decision is not expected until late 2006 at the earliest. At this time, management is unable to predict the outcome of this proceeding. If a rate reduction were ultimately ordered, it would adversely impact future results of operations and cash flows.

In a separate matter in March 2006, the LPSC closed its inquiry into SWEPCo's fuel and purchased power procurement activities during the period January 1, 2005 through October 31, 2005. The LPSC approved the LPSC staff's report, which concluded that SWEPCo's activities were appropriate and did not identify any disallowances or areas for improvement.

Risks Related to Owning and Operating Generating Assets and Selling Power

The amount we charge third parties for using our transmission facilities may be reduced and not recovered. (Applies to AEP and AEP's East zone public utility subsidiaries.)

In July 2003, the FERC issued an order directing PJM and the MISO to make compliance filings for their respective OATTs to eliminate the transaction-based charges for through and out (T&O) transmission service on transactions where the energy is delivered within the proposed MISO and PJM expanded regions (Combined Footprint). The elimination of the T&O rates reduces the transmission service revenues collected by the RTOs and thereby reduces the revenues received by transmission owners under the RTOs' revenue distribution protocols. To mitigate the impact of lost T&O revenues, the FERC approved temporary replacement SECA transition rates beginning in December 2004 and extending through March 2006. SECA fees of \$174 million were collected subject to refund while FERC considers the issue. Approximately \$19 million of these recorded SECA revenues billed by PJM were never collected. The AEP East companies filed a motion with the FERC to force these parties to pay their SECA billings. The FERC has not yet acted on the motion.

Intervenors in the SECA proceeding object to the SECA rates and our method of determining those rates. SECA hearings were held in May 2006 to determine whether any of the SECA revenues should be refunded. Management

has negotiated settlements with certain major intervenors and is engaged in settlement talks with other intervenors. Based on those negotiations, the AEP East companies provided for \$22 million in net refunds. Unless all intervenor claims are fully settled, the FERC is expected to issue a decision in the third quarter of 2006. At this time, management is unable to determine whether the outcome of the FERC's SECA rate proceeding and AEP's motion to force payment of unpaid invoices will have any additional adverse impact on future results of operations and cash flows.

SECA transition rates have not fully compensated AEP for lost T&O revenues. SECA transition rates expired at the end of March 2006, and all transmission costs that would otherwise have been covered by T&O rates in the Combined Footprint are now subject to recovery from native load customers of AEP's East zone public utility subsidiaries. The status of such state retail rate proceedings is as follows:

- In Kentucky, KPCo settled a rate case, which provided for the recovery of its share of the transmission revenue shortfall starting March 30, 2006.
- In Ohio, recovery of CSPCo's and OPCo's share of lost T&O/SECA transmission revenues began retroactive to April 1, 2006 under a May 2006 PUCO order.
- In West Virginia, APCo settled a rate case, which provided for the recovery of its share of the T&O/SECA transmission revenue reductions beginning July 28, 2006.
- In Virginia, APCo filed a request for revised rates, which includes recovery of its share of the T&O/SECA transmission revenue reductions starting October 2, 2006, subject to refund.
- In Indiana, I&M is precluded by a rate cap from requesting an increase to its rates until July 1, 2007.

In addition to seeking retail rate recovery from the applicable states, AEP and another member of PJM have filed an application with the FERC seeking compensation from other unaffiliated members of PJM for the costs associated with those members' use of our respective transmission assets. A majority of PJM members have filed in opposition to the proposal. In July 2006, an ALJ at FERC rendered a decision recommending that the current transmission rates are unjust and unreasonable and should be revised effective April 1, 2006, when SECA rates expired. The ALJ recommended a regional rate design that should, if approved, result in recovery of most, if not all, of the shortfall due to the loss of the T&O/SECA rates. However, the ALJ recommended a phase-in of the new rates, which limits increases of any one pricing zone to 10% per year.

Management is unable to predict whether the FERC will approve either the ALJ's decision or another regional rate to mitigate the loss of T&O/SECA revenues, or if not, when, and if, the effect of the loss of T&O/SECA transmission revenues will be recoverable on a timely basis in each of the AEP East state retail jurisdictions and/or from transmission users within the PJM region.

Risks Relating to State Restructuring

Our Rate Stabilization Plans in Ohio may be modified by the PUCO such that our deferred costs may not be recovered and rates may be reduced. (Applies to AEP, OPCo and CSPCo)

In January 2005, the PUCO approved Rate Stabilization Plans (RSPs) for CSPCo and OPCo. The RSPs provide, among other things, for CSPCo and OPCo to raise their generation rates on an annual basis through 2008 by 3% and 7%, respectively. The RSPs also provide for possible additional annual generation rate increases of up to an average of 4% per year for specified costs. The RSPs also provide that CSPCo and OPCo can recover certain environmental carrying costs, PJM-related administrative costs and certain congestion costs. As of June 30, 2006, the unamortized RSP deferrals were \$8 million for CSPCo and \$39 million for OPCo.

In the second quarter of 2005, the Ohio Consumers' Counsel filed an appeal to the Ohio Supreme Court that challenged the validity of the RSPs under Ohio's electricity restructuring law. In May 2006, the Ohio Supreme Court remanded the rate stabilization plan of First Energy on the grounds that it failed to provide customers with a competitive bid generation supply option, as contemplated by the restructuring law. In July 2006, the Ohio Supreme Court vacated the PUCO's RSP order for CSPCo and OPCo, which did not include a competitive process, and remanded the case to the PUCO for further proceedings.

The PUCO has not yet acted on the remand of the RSP order. In the first six months of 2006, CSPCo and OPCo each have collected an additional \$54 million as a result of the RSPs. If the PUCO were to modify the rate increases authorized in its RSP order, it could have a material effect on future results of operations and cash flows. Pending action by the PUCO on the remand, CSPCo's and OPCo's rates and the recovery of the RSP deferred regulatory assets will continue.

We are contractually required to operate a power generation facility that may indirectly force us to sell the facility's excess energy at a loss. (Applies to AEP.)

We have agreed to lease from Juniper Capital L.P. a non-regulated merchant power generation facility ("Facility") near Plaquemine, Louisiana. We sublease the Facility to Dow. We operate the Facility for Dow. Dow uses a portion of the energy produced by the Facility and sells the excess power to us. We have agreed to sell up to all of the excess 800 MW to Tractebel at a price that is currently in excess of market. Tractebel alleged that the power purchase agreement was unenforceable. This agreement is now being litigated. A bench trial was conducted in March and April 2005. In August 2005, a federal judge ruled that Tractebel had breached the contract and awarded us damages of \$123 million plus prejudgment interest. Both parties have filed appeals. In January 2006, the trial court increased AEP's judgment against Tractebel to \$173 million plus prejudgment interest. In March 2006, the trial judge amended the January 2006 order to eliminate the additional \$50 million damage award. If the trial award is reversed or if Tractebel does not pay the judgment, our cash flow will be adversely affected. If the power agreement is held to be unenforceable, we will be required to find new purchasers for up to 800 MW. There can be no assurance that the power produced will be sold at prices that will exceed our costs to produce it. If that were the case, as a result of our obligations to Dow, we would be required to operate the Facility at a loss.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

The following table provides information about purchases by AEP (or its publicly-traded subsidiaries) during the quarter ended June 30, 2006 of equity securities that are registered by AEP (or its publicly-traded subsidiaries) pursuant to Section 12 of the Exchange Act:

ISSUER PURCHASES OF EQUITY SECURITIES

| Period | Total Number of Shares Purchased | Average Price Paid per Share | Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs | Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs |
|---------------------|----------------------------------|------------------------------|--|--|
| 04/01/06 - 04/30/06 | 87 (a) | \$ 75.48 | - | - |
| 05/01/06 - 05/31/06 | 182 (b)(c) | 79.12 | - | - |
| | 13(d) | 89.00 | - | - |

06/01/06 -
06/30/06

- (a) OPCo repurchased 87 shares of its 4.50% cumulative preferred stock, in privately-negotiated transactions outside of an announced program.
- (b) APCo repurchased 172 shares of its 4.50% cumulative preferred stock, in privately-negotiated transactions outside of an announced program.
- (c) TCC repurchased 10 shares of its 4.00% cumulative preferred stock, in a privately-negotiated transaction outside of an announced program.
- (d) SWEPCo repurchased 13 shares of its 5.00% cumulative preferred stock, in a privately-negotiated transaction outside of an announced program.

Item 4. Submission of Matters to a Vote of Security Holders

AEP

The annual meeting of shareholders was held in Charleston, West Virginia, on April 25, 2006. The holders of shares entitled to vote at the meeting or their proxies cast votes at the meeting with respect to the following two matters, as indicated below:

1. Election of thirteen directors to hold office until the next annual meeting and until their successors are duly elected. Each nominee for director received the votes of shareholders as follows:

| | No. of Shares Voted For | No. of Shares Abstaining |
|-----------------------|-------------------------------|--------------------------------|
| E. R. Brooks | 326,978,463 | 16,644,553 |
| Donald M. Carlton | 337,696,430 | 5,926,586 |
| Ralph D. Crosby, Jr. | 338,248,329 | 5,374,687 |
| John P. DesBarres | 338,149,560 | 5,473,456 |
| Robert W. Fri | 334,047,720 | 9,575,296 |
| Linda A Goodspeed | 336,739,164 | 6,883,852 |
| William R. Howell | 337,392,774 | 6,230,242 |
| Lester A. Hudson, Jr. | 332,505,104 | 11,117,912 |
| Michael G. Morris | 334,335,800 | 9,287,216 |
| Lionel L. Nowell, III | 336,703,400 | 6,919,616 |
| Richard L. Sandor | 334,137,756 | 9,485,260 |
| Donald G. Smith | 334,080,282 | 9,542,734 |
| Kathryn D. Sullivan | 337,753,755 | 5,869,261 |

2. Ratification of the appointment of the firm of Deloitte & Touche LLP as the independent registered public accounting firm for 2006. The proposal was approved by a vote of the shareholders as follows:

| | |
|---------------|-------------|
| Votes FOR | 314,948,910 |
| Votes AGAINST | 25,137,761 |
| V o t e s | 3,536,345 |
| ABSTAINED | |

APCo

The annual meeting of stockholders was held on April 25, 2006 at 1 Riverside Plaza, Columbus, Ohio. At the meeting, 13,499,500 votes were cast FOR each of the following nine persons for election as directors and there were no votes withheld and such persons were elected directors to hold office for one year or until their successors are elected and qualify:

| | |
|-----------------|------------------|
| Carl L. English | Robert P. Powers |
| John B. Keane | Stephen P. Smith |
| Holly K. | Susan Tomasky |
| Koeppel | |
| Venita | Dennis E. Welch |
| McCellon-Allen | |
| Michael G. | |
| Morris | |

TCC

Pursuant to action by written consent in lieu of an annual meeting of the sole shareholder dated April 13, 2006, the following nine persons were elected directors to hold office for one year or until their successors are elected and qualify:

| | |
|-----------------|------------------|
| Carl L. English | Robert P. Powers |
| Thomas M. | Stephen P. Smith |
| Hagan | |
| John B. Keane | Susan Tomasky |
| Venita | Dennis E. Welch |
| McCellon-Allen | |
| Michael G. | |
| Morris | |

I&M

Pursuant to action by written consent in lieu of an annual meeting of the sole shareholder dated April 25, 2006, the following thirteen persons were elected directors to hold office for one year or until their successors are elected and qualify:

| | |
|-----------------|------------------|
| Karl G. Boyd | Venita |
| | McCellon-Allen |
| Carl L. English | Susanne M. |
| | Moorman Rowe |
| Allen R. | Michael G. |
| Glassburn | Morris |
| JoAnn M. | Robert P. Powers |
| Grevenow | |
| Patrick C. Hale | Marsha P. Ryan |
| Holly K. | Susan Tomasky |
| Koeppel | |
| Marc E. Lewis | |

OPCo

The annual meeting of shareholders was held on May 2, 2006 at 1 Riverside Plaza, Columbus, Ohio. At the meeting there were 27,952,473 votes cast FOR each of the following nine persons for election as directors and there were no votes withheld and such persons were elected directors to hold office for one year or until their successors are elected and qualify:

| | |
|-----------------|------------------|
| Carl L. English | Robert P. Powers |
| John B. Keane | Stephen P. Smith |
| H o l l y K . | Susan Tomasky |
| Koeppel | |
| Venita | Dennis E. Welch |
| McCellon-Allen | |
| Michael G. | |
| Morris | |

SWEPCo

Pursuant to action by written consent in lieu of an annual meeting of the sole shareholder dated April 12, 2006, the following nine persons were elected directors to hold office for one year or until their successors are elected and qualify:

| | |
|-----------------|------------------|
| Carl L. English | Robert P. Powers |
| Thomas M. | Stephen P. Smith |
| Hagan | |
| John B. Keane | Susan Tomasky |
| Venita | Dennis E. Welch |
| McCellon-Allen | |
| Michael G. | |
| Morris | |

Item 5. Other Information

NONE

Item 6. Exhibits

AEP, APCo and OPCo

10(a) - AEP System Stock Ownership Requirement Plan (As Amended and Restated Effective January 1, 2006), executed May 30, 2006 and as amended June 5, 2006.

AEP, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

12 - Computation of Consolidated Ratio of Earnings to Fixed Charges.

AEP

31(a) - Certification of AEP Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31(c) - Certification of AEP Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

31(b) - Certification of Registrant Subsidiaries' Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31(d) - Certification of Registrant Subsidiaries' Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

AEP, AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC

32(a) - Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.

32(b) - Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, each registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature for each undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

AMERICAN ELECTRIC POWER COMPANY, INC.

By: /s/Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

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

By: /s/Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

Date: August 4, 2006

