

American Electric Power

2007 Annual Report

**Audited Consolidated Financial Statements and
Management's Financial Discussion and Analysis**



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GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated domestic electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, asset management and commercial and industrial sales in the deregulated Texas market.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AFUDC	Allowance for Funds Used During Construction.
ALJ	Administrative Law Judge.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APSC	Arkansas Public Service Commission.
ARO	Asset Retirement Obligations.
CAA	Clean Air Act.
CO ₂	Carbon Dioxide.
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 generating capacity allocation. This agreement was amended in May 2006 to remove TCC and TNC. AEPSC acts as the agent.
CTC	Competition Transition Charge.
CWIP	Construction Work in Progress.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
DOE	United States Department of Energy.
DOJ	United States Department of Justice.
E&R	Environmental compliance and transmission and distribution system reliability.
EaR	Earnings at Risk, a method to quantify risk exposure.
EITF	Financial Accounting Standards Board's Emerging Issues Task Force.
ERCOT	Electric Reliability Council of Texas.
ETA	Electric Transmission America, LLC a 50% equity interest joint venture with MidAmerican Energy Holdings Company formed to own and operate electric transmission facilities in North America outside of ERCOT.

Term	Meaning
ETT	Electric Transmission Texas, LLC, a 50% equity interest joint venture with MidAmerican Energy Holdings Company formed to own and operate electric transmission facilities in ERCOT.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN	FASB Interpretation No.
FIN 46	FASB Interpretation No. 46, “Consolidation of Variable Interest Entities.”
FIN 47	FASB Interpretation No. 47, “Accounting for Conditional Asset Retirement Obligations.”
FIN 48	FIN 48, “Accounting for Uncertainty in Income Taxes” and FASB Staff Position FIN 48-1 “Definition of <i>Settlement</i> in FASB Interpretation No. 48.”
GAAP	Accounting Principles Generally Accepted in the United States of America.
GHG	Greenhouse gases.
HPL	Houston Pipeline Company, a former AEP subsidiary.
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.
IPP	Independent Power Producer.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
JMG	JMG Funding LP.
KGPCo	Kingsport Power Company, an AEP electric distribution subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
KWH	Kilowatthour.
LIG	Louisiana Intrastate Gas, a former AEP subsidiary.
LPSC	Louisiana Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MLR	Member load ratio, the method used to allocate AEP Power Pool transactions to its members.
MPSC	Michigan Public Service Commission.
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.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.

Term	Meaning
PATH	Potomac Appalachian Transmission Highline, LLC and its subsidiaries, a joint venture with Allegheny Energy Inc. formed to own and operate electric transmission facilities in PJM.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
PUHCA	Public Utility Holding Company Act.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants; APCo, CSPCo, I&M, OPCo, PSO and SWEPCo.
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.
RSP	Rate Stabilization Plan.
RTO	Regional Transmission Organization.
S&P	Standard and Poor's.
SCR	Selective Catalytic Reduction.
SEC	United States Securities and Exchange Commission.
SECA	Seams Elimination Cost Allocation.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SFAS 71	Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation."
SFAS 109	Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes."
SFAS 133	Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities."
SFAS 143	Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations."
SFAS 157	Statement of Financial Accounting Standards No. 157, "Fair Value Measurements."
SFAS 158	Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans."
SFAS 159	Statement of Financial Accounting Standards No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities."
SIA	System Integration Agreement.
SNF	Spent Nuclear Fuel.
SO ₂	Sulfur Dioxide.
SPP	Southwest Power Pool.
Stall Unit	J. Lamar Stall Unit at Arsenal Hill Plant.
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.).

Term	Meaning
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.
Turk Plant	John W. Turk, Jr. Plant.
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 and performance 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 (including our ability to obtain any necessary regulatory approvals and permits) 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, soot or particulate matter and other substances.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance).
- Resolution of litigation (including disputes arising from the bankruptcy of Enron Corp. and related matters).
- Our ability to constrain operation and maintenance costs.
- The economic climate and growth in our service territory and changes in market demand and demographic patterns.
- Inflationary and interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to refinance existing debt at attractive rates.
- 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.
- Actions of rating agencies, including changes in the ratings of debt.
- Volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities.
- Changes in utility regulation, including the potential for new legislation in Ohio and the allocation of costs within RTOs.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- The impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust.
- 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.

The registrants expressly disclaim any obligation to update any forward-looking information.

AEP COMMON STOCK AND DIVIDEND INFORMATION

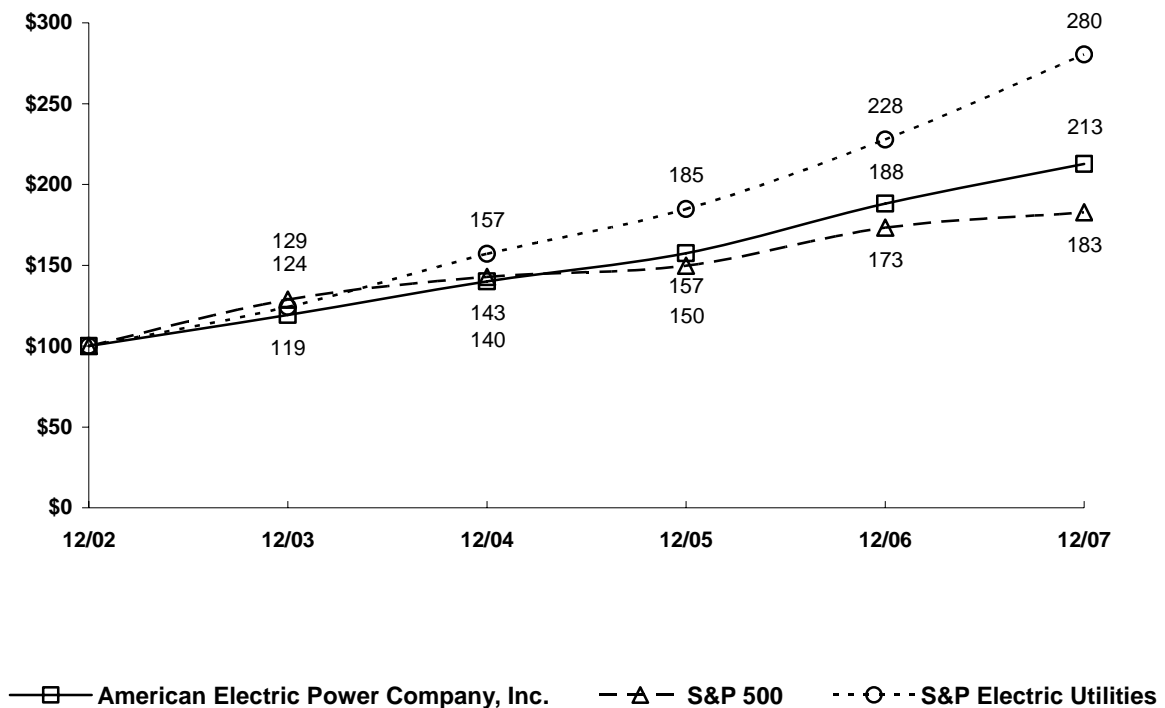
The AEP common stock quarterly high and low sales prices, quarter-end closing price and the cash dividends paid per share are shown in the following table:

Quarter Ended	High	Low	Quarter-End Closing Price	Dividend
December 31, 2007	\$ 49.49	\$ 45.05	\$ 46.56	\$ 0.41
September 30, 2007	48.83	42.46	46.08	0.39
June 30, 2007	51.24	43.39	45.04	0.39
March 31, 2007	49.47	41.67	48.75	0.39
December 31, 2006	\$ 43.13	\$ 36.49	\$ 42.58	\$ 0.39
September 30, 2006	37.30	34.10	36.37	0.37
June 30, 2006	35.19	32.27	34.25	0.37
March 31, 2006	38.48	33.96	34.02	0.37

AEP common stock is traded principally on the New York Stock Exchange. At December 31, 2007, AEP had approximately 105,000 registered shareholders.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among American Electric Power Company, Inc., The S&P 500 Index
And The S&P Electric Utilities Index



* \$100 invested on 12/31/02 in stock or index-including reinvestment of dividends. Fiscal year ending December 31.

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www.researchdatagroup.com/S&P.htm

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SELECTED CONSOLIDATED FINANCIAL DATA

	<u>2007</u>	<u>2006</u>	<u>2005</u>	<u>2004</u>	<u>2003</u>
	(in millions)				
STATEMENTS OF INCOME DATA					
Total Revenues	\$ 13,380	\$ 12,622	\$ 12,111	\$ 14,245	\$ 14,833
Operating Income	\$ 2,319	\$ 1,966	\$ 1,927	\$ 1,983	\$ 1,743
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	\$ 1,144	\$ 992	\$ 1,029	\$ 1,127	\$ 522
Discontinued Operations, Net of Tax	24	10	27	83	(605)(a)
Extraordinary Loss, Net of Tax	(79)	-	(225)(b)	(121)	-
Cumulative Effect of Accounting Changes, Net of Tax	-	-	(17)	-	193
Net Income	<u>\$ 1,089</u>	<u>\$ 1,002</u>	<u>\$ 814</u>	<u>\$ 1,089</u>	<u>\$ 110</u>
BALANCE SHEETS DATA					
	(in millions)				
Property, Plant and Equipment	\$ 46,145	\$ 42,021	\$ 39,121	\$ 37,294	\$ 36,031
Accumulated Depreciation and Amortization	16,275	15,240	14,837	14,493	14,014
Net Property, Plant and Equipment	<u>\$ 29,870</u>	<u>\$ 26,781</u>	<u>\$ 24,284</u>	<u>\$ 22,801</u>	<u>\$ 22,017</u>
Total Assets	\$ 40,366	\$ 37,987	\$ 36,172	\$ 34,636	\$ 36,736
Common Shareholders' Equity	\$ 10,079	\$ 9,412	\$ 9,088	\$ 8,515	\$ 7,874
Cumulative Preferred Stocks of Subsidiaries	\$ 61	\$ 61	\$ 61	\$ 127	\$ 137
Long-term Debt (c)	\$ 14,994	\$ 13,698	\$ 12,226	\$ 12,287	\$ 14,101
Obligations Under Capital Leases (c)	\$ 371	\$ 291	\$ 251	\$ 243	\$ 182
COMMON STOCK DATA					
Basic Earnings (Loss) per Common Share:					
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	\$ 2.87	\$ 2.52	\$ 2.64	\$ 2.85	\$ 1.35
Discontinued Operations, Net of Tax	0.06	0.02	0.07	0.21	(1.57)
Extraordinary Loss, Net of Tax	(0.20)	-	(0.58)	(0.31)	-
Cumulative Effect of Accounting Changes, Net of Tax	-	-	(0.04)	-	0.51
Basic Earnings Per Share	<u>\$ 2.73</u>	<u>\$ 2.54</u>	<u>\$ 2.09</u>	<u>\$ 2.75</u>	<u>\$ 0.29</u>
Weighted Average Number of Basic Shares Outstanding (in millions)	399	394	390	396	385
Market Price Range:					
High	\$ 51.24	\$ 43.13	\$ 40.80	\$ 35.53	\$ 31.51
Low	\$ 41.69	\$ 32.27	\$ 32.25	\$ 28.50	\$ 19.01
Year-end Market Price	\$ 46.56	\$ 42.58	\$ 37.09	\$ 34.34	\$ 30.51
Cash Dividends Paid per Common Share	\$ 1.58	\$ 1.50	\$ 1.42	\$ 1.40	\$ 1.65
Dividend Payout Ratio	57.88%	59.1%	67.9%	50.9%	569.0%
Book Value per Share	\$ 25.17	\$ 23.73	\$ 23.08	\$ 21.51	\$ 19.93

(a) Discontinued Operations, Net of Tax for 2003 primarily represents UK Generation Plants.

(b) Extraordinary Loss, Net of Tax for 2005 reflects TCC's stranded cost. See Note 2.

(c) Including portion due within one year.

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

American Electric Power Company, Inc. (AEP) is one of the largest investor-owned electric public utility holding companies in the United States. Our electric utility operating companies provide generation, transmission and distribution services to more than five million retail customers in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia.

We operate an extensive portfolio of assets including:

- Approximately 38,000 megawatts of generating capacity, one of the largest complements of generation in the U.S., the majority of which provides a significant cost advantage in most of our market areas.
- Approximately 39,000 miles of transmission lines, including 2,116 miles of 765kV lines, the backbone of the electric interconnection grid in the Eastern U.S.
- 212,781 miles of distribution lines that deliver electricity to 5.2 million customers.
- Substantial coal transportation assets (more than 8,400 railcars, 2,650 barges, 52 towboats and a coal handling terminal with 20 million tons of annual capacity).

EXECUTIVE OVERVIEW

BUSINESS STRATEGY

Our mission is to bring comfort to our customers, support business and commerce and build strong communities. We invest in our core utility business operations to execute our mission. Our objective is to be an economical, reliable and safe provider of electric energy to the markets that we serve. We plan to buy or build additional generation to meet franchise service obligations to support the growth of the economies of our eleven state service territory. Our plan entails designing, building, improving and operating reasonably priced, environmentally-compliant, efficient sources of power and maximizing the amount of power delivered to retail and wholesale customers from these facilities. We intend to maintain and enhance our position as a safe and reliable provider of electric energy by making significant investments in environmental and reliability upgrades. We will seek to recover the cost of our new utility investments in a manner that results in reasonable rates for our customers while providing a fair return for our shareholders through a stable stream of cash flows, enabling us to pay dependable, competitive dividends. We operate our generating assets to maximize our productivity and profitability after meeting our native load requirements.

In summary, our business strategy is to:

- Respect our employees' health, safety and well being and give them the opportunity to be as successful as they can be.
- Meet the energy needs of our customers in ways that improve their quality of life and protect the environment today and for generations to come.
- Improve the environmental and safety performance of our generating fleet, and grow that fleet.
- Set the standards for safety, efficiency and reliability in our electric transmission and distribution systems.
- Nurture strong and productive relationships with public officials and regulators.
- Provide leadership, integrity and compassion as a corporate citizen to every community we serve.

OUTLOOK FOR 2008

We remain focused on the fundamental earning power of our utilities and are committed to maintaining our credit quality in order to accomplish our strategy. To achieve our goals we plan to:

- Continue construction of over 1,800 MW of additional new generation in Ohio, Arkansas, Louisiana and Oklahoma with commercial operation dates ranging from 2008 through 2012.
- Continue to pursue regulatory approval for our proposed IGCC plants in Ohio and West Virginia and move forward with the engineering and design of these plants.
- Aggressively seek needed rate increases by developing innovative rate making approaches that obtain favorable resolutions to our numerous rate proceedings.
- Continue developing strong regulatory relationships through operating company interaction with the various regulatory bodies.
- Invest in transmission projects such as PATH, ETT, ETA and others to ensure competitive energy prices for electric consumers in and around congested areas.
- Maintain our strong financial condition and credit ratings.
- Control our operating and maintenance costs.

There are, nevertheless, certain risks and challenges that must be overcome including:

- Intervention in current regulatory proceedings in Indiana, Oklahoma, Louisiana and at the FERC to keep rates down at the expense of a fair return.
- Legislative activity in Ohio regarding the future regulatory framework.
- Fuel cost volatility and fuel cost recovery, including related transportation issues.
- Wholesale market volatility.
- Plant availability.
- Weather.

Regulatory Activity

In 2008, our significant regulatory activities will include:

- Pursuing favorable resolutions of our pending base rate case in Indiana, E&R filings in Virginia and improve inadequate cost recoveries in Oklahoma.
- Obtaining a successful legislative outcome regarding Ohio's future regulatory framework.
- Seeking approval for our new generation projects in Ohio, Oklahoma, West Virginia, Virginia, Arkansas, Texas and Louisiana.
- Directing legal proceedings regarding appeals related to Texas stranded cost recoveries.
- Seeking approval to construct transmission projects in ERCOT with appropriate incentives.
- Managing regulatory proceedings before the FERC seeking:
 - proper regional and super-regional transmission rates in our eastern transmission zone,
 - favorable settlement of SECA rates collected subject to refund and
 - approval to construct transmission projects in PJM with appropriate incentives.

Fuel Costs

Spot prices for coal generally increased for much of 2007, but late in the year, prices for eastern bituminous coal increased significantly. Prices for natural gas have been less volatile compared to the price spikes seen in 2005 and early 2006. Prices for fuel oil continue to be near record highs and very volatile. In 2007, we experienced a 4% increase from the prior year in delivered coal costs across the AEP System. This increase is favorable as compared to an expectation near the end of 2006 that delivered coal costs would be 7 to 9% higher. The favorable result this year is primarily due to discounts received through the purchase of synfuel at some of our facilities.

We expect coal prices to increase by 13% in 2008. We continue to see increases in prices due to expiring lower priced coal and transportation contracts being replaced with higher priced contracts. Going forward, we have some exposure to price risk related to our open positions for coal, natural gas and fuel oil especially since we do not have an active fuel cost recovery adjustment mechanism in Ohio, which represents approximately 20% of our fuel costs. Fuel cost adjustment rate clauses in our other jurisdictions will help offset future negative impacts of fuel price increases on our gross margins.

Capital Expenditures

Our current projections call for capital expenditures of approximately \$11.2 billion from 2008-2010. For 2008, we forecast approximately \$3.83 billion in construction expenditures, excluding allowances for the estimated cost of borrowed and equity funds used to finance construction projects (AFUDC), as follows:

	<u>(in millions)</u>
Generation	\$ 1,192
Distribution	1,031
Environmental	875
Transmission	564
Corporate	168
Total Construction Expenditures	<u>\$ 3,830</u>

In addition, we expect to invest approximately \$255 million in our transmission joint ventures from 2008 – 2010, of which approximately \$35 million will be in 2008.

Corporate Sustainability Reporting

We will publish our second Corporate Responsibility report in 2008 reporting on our 2007 performance. The scope of our 2008 report will reach beyond environmental issues and address other matters that create risk to our sustainability into the future. The report will be developed using the sustainability reporting guidelines issued by the Global Reporting Initiative and will address issues such as leadership, strategy and management, workforce issues including safety and health, climate change, environmental performance and energy security, reliability and growth. In preparing this report we also conducted a total of eight stakeholder meetings with customers, employees, state and regional environmental groups, community leaders, regulators, investors and with Ceres, a national network of investors, environmental organizations and other public interest groups that work with companies on sustainability issues. The process enabled us to hear from many more stakeholders and to engage with them at our operating companies and power plants, as well as with our corporate team.

2007 RESULTS

We had a year of continued improvement and many accomplishments in 2007. Our total shareholder return was 13.1% and we increased our quarterly dividend 5.1% to \$0.41 per share. We began construction activities for new generation projects in Oklahoma, Louisiana and Arkansas; continued work on engineering and design for new clean-coal technology IGCC plants in Ohio and West Virginia; and formed joint ventures to invest in transmission facilities in PJM, ERCOT and other regions. We sold our interest in Sweeny and purchased 1,576 MW of gas-fired generating capacity in the east. We also acquired a partially completed 580 MW gas-fired generating station in Dresden, Ohio expected to be available in 2010.

We increased revenues as a result of our significant regulatory activities in 2007. Base rate increases finalized in 2007 with implemented rates were:

Operating Company	Jurisdiction	Revised Annual Rate Increase Request	Implemented Annual Rate Increase	Date of Rate Increase	Date of Final Order
(in millions)					
APCo	Virginia	\$ 198(a)	\$ 24(a)	October 2006	May 2007
OPCo	Ohio	8	4	May 2007	October 2007
CSPCo	Ohio	24	19	May 2007	October 2007
TCC	Texas	70	43	June 2007	January 2008
TNC	Texas	22	14	June 2007	May 2007
PSO	Oklahoma	48	10(b)	July 2007	October 2007
OPCo	Ohio	68	68	January 2008	N/A
CSPCo	Ohio	27	27	January 2008	N/A
OPCo	Ohio	15	5(c)	February 2008	January 2008
CSPCo	Ohio	40	29(c)	February 2008	January 2008

- (a) The difference between the requested and implemented amounts of annual rate increase is partially offset by approximately \$35 million of incremental E&R costs which APCo recorded as a regulatory asset. APCo will file for recovery of these costs through the E&R surcharge mechanism in 2008. APCo also implemented, beginning September 1, 2007, a net \$50 million reduction in credits to customers for off-system sales margins as part of its July 2007 fuel clause filing under the new re-regulation legislation.
- (b) Implemented \$9 million in July 2007, increased to \$10 million in October 2007.
- (c) In January 2008, the PUCO granted additional requested recoveries of increased PJM costs through the TCRR.

In Virginia, APCo filed the following non-base rate requests in July 2007 with the Virginia SCC:

Operating Company	Jurisdiction	Cost Type	Request	Implemented Annual Rate Increase	Date of Rate Increase	Date of Final Order
(in millions)						
APCo	Virginia	Incremental E&R	\$ 60	\$ 49	January 2008	December 2007
APCo	Virginia	Fuel, Off-system Sales	33(a)	4(a)	September 2007	February 2008

- (a) The Virginia SCC approved the off-system sales margin sharing of 75% to customers and 25% to APCo effective September 2007.

In Indiana, the IURC approved a decrease in book depreciation expense for I&M effective June 2007 of \$69 million annually. We expect that the lower depreciation rates will affect new base rates beginning in early 2009 upon final authorization of I&M's Indiana rate filing.

RESULTS OF OPERATIONS

Segments

Our primary business strategy and the core of our business focus is on our electric utility operations. Within our Utility Operations segment, we centrally dispatch all generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. Generation/supply in Ohio continues to have commission-determined rates transitioning from cost-based to market-based rates. The legislature in Ohio is currently considering possibly returning to some form of cost-based rate-regulation or a hybrid form of rate-regulation for generation. While our Utility Operations segment remains our primary business segment, other segments include our MEMCO Operations segment with our significant barging activities and our Generation and Marketing segment, which includes our nonregulated generating, marketing and risk management activities in the ERCOT market area. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

Our reportable 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.

MEMCO Operations

- Barging operations that annually transport approximately 35 million tons of coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers. Approximately 39% of the barging is for agricultural products, 30% for coal, 14% for steel and 17% for other commodities.

Generation and Marketing

- Wind farms and marketing and risk management activities primarily in ERCOT. Our 50% interest in Sweeny Cogeneration Plant was sold in October 2007. See “Sweeny Cogeneration Plant” section of Note 8.

The table below presents our consolidated Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change by segment for the years ended December 31, 2007, 2006 and 2005.

	Years Ended December 31,		
	2007	2006	2005
	(in millions)		
Utility Operations	\$ 1,031	\$ 1,028	\$ 1,018
MEMCO Operations	61	80	21
Generation and Marketing	67	12	16
All Other (a)	(15)	(128)	(26)
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	\$ 1,144	\$ 992	\$ 1,029

(a) All Other includes:

- Parent company’s guarantee revenue received from affiliates, interest income and interest expense and other nonallocated costs.
- Tax and interest expense adjustments related to our UK operations and SEEBOARD, which were not eligible for discontinued operations treatment and were sold in 2004 and 2002, respectively.
- Our gas pipeline and storage operations, which were sold in 2004 and 2005.
- Other energy supply related businesses, including the Plaquemine Cogeneration Facility, which was sold in 2006. See “Plaquemine Cogeneration Facility” section of Note 8.

AEP Consolidated

2007 Compared to 2006

Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change in 2007 increased \$152 million compared to 2006 primarily due to a \$136 million after-tax impairment recorded in 2006 related to the sale of the Plaquemine Cogeneration Facility. Despite retail rate increases implemented in Ohio, Kentucky, Oklahoma, Texas, Virginia and West Virginia and favorable weather, Utility Operations earnings were essentially flat due to increases in interest expense, operation and maintenance expenses related to storm restoration in Oklahoma and the NSR settlement.

Average basic shares outstanding increased to 399 million in 2007 from 394 million in 2006 primarily due to the issuance of shares under our incentive compensation and dividend reinvestment plans. Actual shares outstanding were 400 million as of December 31, 2007.

2006 Compared to 2005

Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change in 2006 decreased \$37 million compared to 2005 primarily due to a \$136 million after-tax impairment recorded in the third quarter of 2006 related to the sale of the Plaquemine Cogeneration Facility offset by a \$59 million increase in MEMCO Operations earnings. Utility Operations earnings increased \$10 million due to retail rate increases implemented in Ohio, Kentucky, Oklahoma, Virginia and West Virginia mostly offset by unfavorable weather, decreases in transmission revenues from the loss of wholesale SECA transmission rates and increases in regulatory amortization and operating expenses.

Average basic shares outstanding increased to 394 million in 2006 from 390 million in 2005 primarily due to the issuance of shares under our incentive compensation and dividend reinvestment plans. Actual shares outstanding were 397 million as of December 31, 2006.

Our results of operations are discussed below by operating segment.

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 in order to further understand the key drivers of the segment. Gross margin represents utility operating revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power.

	Years Ended December 31,		
	2007	2006	2005
		(in millions)	
Revenues	\$ 12,655	\$ 12,011	\$ 11,389
Fuel and Purchased Power	4,838	4,669	4,288
Gross Margin	7,817	7,342	7,101
Depreciation and Amortization	1,483	1,435	1,315
Other Operating Expenses	4,129	3,843	3,801
Operating Income	2,205	2,064	1,985
Other Income, Net	102	177	103
Interest Expense and Preferred Stock Dividend Requirements	790	670	595
Income Tax Expense	486	543	475
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	\$ 1,031	\$ 1,028	\$ 1,018

**Summary of KWH Energy Sales for Utility Operations
For the Years Ended December 31, 2007, 2006 and 2005**

	<u>2007</u>	<u>2006</u>	<u>2005</u>
	(in millions of KWH)		
Retail:			
Residential	49,176	47,222	48,720
Commercial	40,545	38,579	38,605
Industrial	57,566	53,914	53,217
Miscellaneous	2,565	2,653	2,745
Total Retail	<u>149,852</u>	<u>142,368</u>	<u>143,287</u>
Wholesale	42,917	44,564	47,785
Texas Wires – Energy delivered to customers served by TNC and TCC in ERCOT	<u>26,682</u>	<u>26,382</u>	<u>26,525</u>
Total KWHs	<u><u>219,451</u></u>	<u><u>213,314</u></u>	<u><u>217,597</u></u>

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 number of customers within each region.

**Summary of Heating and Cooling Degree Days for Utility Operations
For the Years Ended December 31, 2007, 2006 and 2005**

	<u>2007</u>	<u>2006</u>	<u>2005</u>
	(in degree days)		
<u>Eastern Region</u>			
Actual – Heating (a)	3,014	2,477	3,130
Normal – Heating (b)	3,042	3,078	3,088
Actual – Cooling (c)	1,266	923	1,153
Normal – Cooling (b)	978	985	969
<u>Western Region (d)</u>			
Actual – Heating (a)	1,559	1,172	1,377
Normal – Heating (b)	1,588	1,605	1,615
Actual – Cooling (c)	2,244	2,430	2,386
Normal – Cooling (b)	2,181	2,175	2,150

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

2007 Compared to 2006

Reconciliation of Year Ended December 31, 2006 to Year Ended December 31, 2007
Income from Utility Operations Before Discontinued Operations, Extraordinary Loss and
Cumulative Effect of Accounting Change
(in millions)

Year Ended December 31, 2006	\$	1,028
Changes in Gross Margin:		
Retail Margins	372	
Off-system Sales	69	
Transmission Revenues	25	
Other Revenues	<u>9</u>	
Total Change in Gross Margin		475
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(226)	
Gain on Dispositions of Assets, Net	(47)	
Depreciation and Amortization	(48)	
Taxes Other Than Income Taxes	(13)	
Carrying Costs Income	(62)	
Other Income, Net	(13)	
Interest and Other Charges	<u>(120)</u>	
Total Change in Operating Expenses and Other		(529)
Income Tax Expense		<u>57</u>
Year Ended December 31, 2007	<u>\$</u>	<u>1,031</u>

Income from Utility Operations Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change of \$1,031 million in 2007 was essentially flat when compared to 2006. An increase of \$475 million in Gross Margin and a decrease of \$57 million in Income Tax Expense were offset by an increase of \$529 million in Operating Expenses and Other.

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

- Retail Margins increased \$372 million primarily due to the following:
 - A \$98 million increase in rates implemented in our Ohio jurisdictions, a \$63 million rate increase implemented in our other east jurisdictions of Virginia, West Virginia and Kentucky, a \$37 million increase in rates in Texas and a \$16 million rate increase in Oklahoma.
 - A \$105 million increase in usage related to weather. Compared to the prior year, our eastern region and western region experienced 22% and 33% increases, respectively, in heating degree days. Also, our eastern region experienced a 37% increase in cooling degree days which was partially offset by an 8% decrease in cooling degree days in our western region.
 - A \$100 million increase related to increased residential and commercial usage and customer growth.
 - A \$96 million increase due to the return of Ormet, an industrial customer in Ohio, effective January 1, 2007. See “Ormet” section of Note 4.
 - A \$49 million increase in sales to municipal, cooperative and other wholesale customers primarily resulting from new power supply contracts.

These increases were partially offset by:

- A \$67 million decrease in PJM financial transmission rights revenue, net of congestion, primarily due to fewer transmission constraints within the PJM market.
- A \$53 million decrease due to PJM’s revision of its pricing methodology for transmission line losses to marginal-loss pricing effective June 1, 2007. See “PJM Marginal-Loss Pricing” section of Note 4.
- A \$24 million decrease due to increased PJM ancillary costs.

- A \$17 million decrease due to a 2007 provision related to a SWEPCo Texas fuel reconciliation proceeding. See “SWEPCo Fuel Reconciliation – Texas” section of Note 4.
- Margins from Off-system Sales increased \$69 million primarily due to higher trading margins and favorable fuel recovery adjustments in our western territory, offset by lower east physical off-system sales margins mostly due to lower volumes and PJM’s implementation of marginal-loss pricing effective June 1, 2007.
- Transmission Revenues increased \$25 million primarily due to higher revenue in ERCOT and the east.
- Other Revenues increased \$9 million primarily due to higher securitization revenue at TCC resulting from the \$1.7 billion securitization in October 2006 offset by fewer gains on sales of emissions allowances. Securitization revenue represents amounts collected to recover securitization bond principal and interest payments related to TCC’s securitized transition assets and are fully offset by amortization and interest expenses.

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

- Other Operation and Maintenance expenses increased \$226 million primarily due to a \$77 million expense resulting from the NSR settlement and an \$81 million increase in storm restoration primarily in Oklahoma. The remaining increase relates to generation expenses from plant outages and base operations.
- Gain on Disposition of Assets, Net decreased \$47 million primarily related to an earnings sharing agreement with Centrica from the sale of our Texas REPs in 2002. In 2006, we received \$70 million from Centrica for earnings sharing and in 2007 we received \$20 million as the earnings sharing agreement expired.
- Depreciation and Amortization expense increased \$48 million primarily due to increased Ohio regulatory asset amortization related to recovery of IGCC pre-construction costs, increased Texas securitized transition asset amortization and higher depreciable property balances, partially offset by commission-approved lower depreciation rates in Indiana, Michigan and Virginia.
- Carrying Costs Income decreased \$62 million primarily due to TCC’s commencement of stranded cost recovery in October 2006, thus eliminating the accrual of carrying costs income, partially offset by higher carrying costs income related to APCo’s Virginia E&R cost deferrals.
- Interest and Other Charges increased \$120 million primarily due to additional debt issued in 2006 and in 2007 including TCC securitization bonds as well as higher rates on variable rate debt.
- Income Tax Expense decreased \$57 million due to unfavorable federal income tax adjustments in 2006 and favorable state tax return adjustments in 2007.

2006 Compared to 2005

**Reconciliation of Year Ended December 31, 2005 to Year Ended December 31, 2006
Income from Utility Operations Before Discontinued Operations, Extraordinary Loss and
Cumulative Effect of Accounting Change
(in millions)**

Year Ended December 31, 2005	\$ 1,018
<u>Changes in Gross Margin:</u>	
Retail Margins	352
Off-system Sales	(18)
Transmission Revenues	(140)
Other Revenues	47
Total Change in Gross Margin	241
<u>Changes in Operating Expenses and Other:</u>	
Other Operation and Maintenance	(39)
Asset Impairments and Other Related Charges	39
Gain on Dispositions of Assets, Net	(50)
Depreciation and Amortization	(120)
Taxes Other Than Income Taxes	8
Carrying Costs Income	59
Other Income, Net	15
Interest and Other Charges	(75)
Total Change in Operating Expenses and Other	(163)
Income Tax Expense	(68)
Year Ended December 31, 2006	<u>\$ 1,028</u>

Income from Utility Operations Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change increased \$10 million to \$1,028 million in 2006. The key driver of the increase was a \$241 million increase in Gross Margin offset by a \$163 million increase in Operating Expenses and Other and a \$68 million increase in Income Tax Expense.

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

- Retail Margins increased \$352 million primarily due to the following:
 - A \$244 million increase related to new rates implemented in our Ohio jurisdictions as approved by the PUCO in our RSPs, a \$67 million increase related to new rates implemented in other east jurisdictions of Kentucky, West Virginia and Virginia and a \$13 million increase related to new rates implemented in Oklahoma in June 2005.
 - A \$123 million increase related to increased usage and customer growth of which \$63 million relates to the purchase of the Ohio service territory of Monongahela Power in December 2005.
 - A \$70 million increase related to increased sales to municipal, cooperative and other customers primarily as a result of new power supply contracts.
 - A \$55 million increase related to decreased sharing of off-system sales margins with retail customers due to lower off-system sales and changes in the SIA.

These increases were partially offset by:

- A \$148 million increase in delivered fuel cost related to the AEP East companies with inactive, capped or frozen fuel clauses.
- A \$95 million decrease in usage related to mild weather. Compared to the prior year, our eastern region and western region experienced 21% and 15% declines, respectively, in heating degree days. Also compared to the prior year, our eastern region experienced a 20% decrease in cooling degree days.

- Margins from Off-system Sales decreased \$18 million primarily due to lower generation availability in the west due to the sale of STP in May 2005, a reversal of a Texas regulatory provision in 2005 and lower margins from trading activities mostly offset by higher margins in the east.
- Transmission Revenues decreased \$140 million primarily due to the elimination of SECA revenues as of April 1, 2006 and a provision of \$34 million recorded in 2006 related to potential SECA refunds pending settlement negotiations with various intervenors. See the “SECA Revenue Subject to Refund” section of Note 4.
- Other Revenues increased \$47 million primarily due to the sale of emission allowances and increased securitization revenues.

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

- Other Operation and Maintenance expenses increased \$39 million primarily due to increases in generation expenses related to base operations and maintenance, distribution expenses related to vegetation management and service reliability, expenses at the Plaquemine Cogeneration Facility and favorable insurance adjustments which reduced expenses in 2005. These increases were partially offset by favorable variances related to expenses from the January 2005 ice storm in Ohio and Indiana and the recovery of the ice storm expenses in Ohio in 2006 and a decrease in severance costs related to the 2005 staffing and budget review.
- Asset Impairments and Other Related Charges decreased \$39 million due to our retirement of two units at our Conesville Plant in 2005.
- Gain on Disposition of Assets, Net decreased \$50 million primarily 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 \$120 million primarily due to increased Ohio regulatory asset amortization in conjunction with rate increases, increased Texas amortization of the securitized transition assets and higher depreciable property balances.
- Carrying Costs Income increased \$59 million primarily due to negative adjustments in 2005 related to the Texas True-up Proceeding orders received from the PUCT and an increase related to the Virginia environmental and reliability deferred costs.
- Interest and Other Charges increased \$75 million primarily due to additional debt issued in late 2005 and in 2006 and increasing interest rates, partially offset by an increase in allowance for borrowed funds used during construction.
- Income Tax Expense increased \$68 million due to an increase in pretax income, state income taxes, changes in certain book/tax differences accounted for on a flow-through basis and the recording of tax reserve adjustments.

MEMCO Operations

2007 Compared to 2006

Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change from our MEMCO Operations segment decreased from \$80 million in 2006 to \$61 million in 2007. MEMCO operated approximately 10% more barges in 2007 than 2006; however, revenue remained flat as reduced imports, primarily steel and cement continued to depress freight rates and reduce northbound loadings. Operating expenses were up for 2007 compared to 2006 primarily due to the cost of the increased fleet size, rising fuel costs and wage increases.

2006 Compared to 2005

Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change from our MEMCO Operations segment increased from \$21 million in 2005 to \$80 million in 2006. The increase was primarily related to strong demand and a tight supply of barges resulting in increased barge freight rates and utilization. Additionally, 2006 operating conditions for our barging operations improved from 2005 when hurricanes, severe ice and flooding caused increased operating costs.

Generation and Marketing

2007 Compared to 2006

Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change from our Generation and Marketing segment increased from \$12 million in 2006 to \$67 million in 2007. The increase primarily relates to \$37 million of after-tax income from the sale of our equity interest in Sweeny and related contracts. Revenues increased primarily due to certain existing ERCOT energy contracts, which were transferred from our Utility Operations segment on January 1, 2007, and favorable marketing contracts with municipalities and cooperatives in ERCOT. The increase in revenues was partially offset by increased purchased power and operating expenses.

2006 Compared to 2005

Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change from our Generation and Marketing segment in 2006 was essentially flat when compared to 2005.

All Other

2007 Compared to 2006

Loss Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change from All Other decreased from \$128 million in 2006 to \$15 million in 2007. The decrease in the loss primarily relates to a \$136 million after-tax impairment of the Plaquemine Cogeneration Facility in 2006 offset by an increase in interest expense of \$45 million related to the Bank of America and HPL cushion gas dispute and lower income from the sale of investment securities in 2007.

2006 Compared to 2005

Loss Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change from All Other increased from a \$26 million in 2005 to a \$128 million in 2006. The increase primarily relates to the \$136 million after-tax impairment recorded in the third quarter of 2006 related to the sale of the Plaquemine Cogeneration Facility, partially offset by lower interest expense and associated buyback costs related to the redemption of \$550 million of senior unsecured notes in April 2005.

AEP System Income Taxes

Income Tax Expense increased \$31 million between 2006 and 2007 primarily due to an increase in pretax book income, offset in part by recording federal and state income tax adjustments related to recent audit settlements reached with the IRS and other taxing jurisdictions.

Income Tax Expense increased \$55 million between 2005 and 2006 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 and the recording of tax reserve adjustments.

FINANCIAL CONDITION

We measure our financial condition by the strength of our balance sheet and the liquidity provided by our cash flows. During 2007, we maintained our strong financial condition as reflected by our issuance of \$2.6 billion of long-term debt primarily to fund our construction program and retire debt maturities.

Debt and Equity Capitalization

		December 31,				
		2007		2006		
		(\$ in millions)				
Long-term Debt, including amounts due within one year	\$	14,994	58.1 %	\$	13,698	59.1 %
Short-term Debt		660	2.6		18	0.0
Total Debt		15,654	60.7		13,716	59.1
Common Equity		10,079	39.1		9,412	40.6
Preferred Stock		61	0.2		61	0.3
Total Debt and Equity Capitalization	\$	25,794	100.0 %	\$	23,189	100.0 %

Our ratio of debt to total capital increased, as planned, from 59.1% to 60.7% in 2007 due to increased borrowing to support our construction program.

Liquidity

Liquidity, or access to cash, is an important factor in determining our financial stability. We are committed to maintaining adequate liquidity. We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding is arranged. Sources of long-term funding include issuance of common stock or long-term debt and sale-leaseback or leasing agreements.

Credit Markets

We believe we have adequate liquidity under our credit facilities and the ability to issue long-term debt in the current credit markets. In 2008, we expect to increase net borrowings by approximately \$1.8 billion to support our investment in facilities and environmental control equipment. As of December 31, 2007, we have \$1.5 billion of tax-exempt long-term debt sold at auction rates that are reset every 7, 28 or 35 days and are insured by bond insurers previously AAA-rated, namely Ambac Assurance Corporation, Financial Guaranty Insurance Co., MBIA Insurance Corporation and XL Capital Assurance Inc. Due to the exposure that these bond insurers have in connection with recent developments in the subprime credit market, the credit ratings of these insurers have been downgraded or placed on negative outlook. This has contributed to higher interest rates in successful auctions and increasing occurrences of failed auctions, including a number of auctions of our tax-exempt long-term debt. The instruments under which the bonds are issued allow us to convert to other short-term variable-rate structures, term-put structures and fixed-rate structures. We are planning to reduce our outstanding auction rate market securities by redeeming, refunding or converting such debt securities to other permitted modes, including term-put and fixed-rate structures. We expect this to result in additional transaction costs and higher interest charges for this tax-exempt long-term debt.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. At December 31, 2007, our available liquidity was approximately \$2.5 billion as illustrated in the table below:

	<u>Amount</u> <u>(in millions)</u>	<u>Maturity</u>
Commercial Paper Backup:		
Revolving Credit Facility	\$ 1,500	March 2011
Revolving Credit Facility	1,500	April 2012
Total	<u>3,000</u>	
Cash and Cash Equivalents	178	
Total Liquidity Sources	<u>3,178</u>	
Less: AEP Commercial Paper Outstanding	659	
Letters of Credit Drawn	<u>65</u>	
Net Available Liquidity	<u><u>\$ 2,454</u></u>	

In 2007, we amended the terms and extended the maturity of our two credit facilities by one year to March 2011 and April 2012, respectively. The facilities are structured as two \$1.5 billion credit facilities of which \$300 million may be issued under each credit facility as letters of credit.

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 December 31, 2007, we had credit facilities totaling \$3 billion to support our commercial paper program. The maximum amount of commercial paper outstanding during 2007 was \$865 million. The weighted-average interest rate of our commercial paper during 2007 was 5.54%.

Sale of Receivables

In October 2007, we renewed our sale of receivables agreement. The sale of receivables agreement provides a commitment of \$650 million from banks and commercial paper conduits to purchase receivables. Under the agreement, the commitment will increase to \$700 million for the months of August and September to accommodate seasonal demand. This agreement expires in October 2008. We intend to extend or replace the sale of receivables agreement.

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 in our revolving credit agreements. At December 31, 2007, this contractually-defined percentage was 56.6%. Nonperformance of these covenants could result in an event of default under these credit agreements. At December 31, 2007, 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 revolving credit facilities do not permit the lenders to refuse a draw on either facility if a material adverse change occurs.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. At December 31, 2007, we had not exceeded those authorized limits.

Dividend Policy and Restrictions

We have declared common stock dividends payable in cash in each quarter since July 1910, representing 391 consecutive quarters. The Board of Directors increased the quarterly dividend from \$0.39 to \$0.41 per share in October 2007. Future dividends may vary depending upon our profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time.

Credit Ratings

Our current credit ratings are as follows:

	<u>Moody's</u>	<u>S&P</u>	<u>Fitch</u>
AEP Short Term Debt	P-2	A-2	F-2
AEP Senior Unsecured Debt	Baa2	BBB	BBB

In January 2008, Moody's changed its outlook from stable to negative for APCo, SWEPCo, OPCo and TCC. Moody's affirmed its stable outlook for AEP and our other subsidiaries. In February 2008, Fitch downgraded PSO from A- to BBB+ for senior unsecured debt and from BBB+ to BBB for its issuer default rate and preferred stock. 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.

	Years Ended December 31,		
	2007	2006	2005
		(in millions)	
Cash and Cash Equivalents at Beginning of Period	\$ 301	\$ 401	\$ 320
Net Cash Flows from Operating Activities	2,388	2,732	1,877
Net Cash Flows Used for Investing Activities	(3,921)	(3,743)	(1,005)
Net Cash Flows from (Used for) Financing Activities	1,410	911	(791)
Net Increase (Decrease) in Cash and Cash Equivalents	(123)	(100)	81
Cash and Cash Equivalents at End of Period	<u>\$ 178</u>	<u>\$ 301</u>	<u>\$ 401</u>

Cash from operations, combined with a bank-sponsored receivables purchase agreement and short-term borrowings under the credit facilities, provides working capital and allows us to meet other short-term cash needs.

Operating Activities

	Years Ended December 31,		
	2007	2006	2005
		(in millions)	
Net Income	\$ 1,089	\$ 1,002	\$ 814
Less: Discontinued Operations, Net of Tax	(24)	(10)	(27)
Income Before Discontinued Operations	1,065	992	787
Depreciation and Amortization	1,513	1,467	1,348
Other	(190)	273	(258)
Net Cash Flows from Operating Activities	<u>\$ 2,388</u>	<u>\$ 2,732</u>	<u>\$ 1,877</u>

Net Cash Flows from Operating Activities decreased in 2007 due to the CTC refunds in Texas, increased customer accounts receivable reflecting new contracts in the generation and marketing segment and increased utility segment receivables.

Net Cash Flows from Operating Activities were \$2.4 billion in 2007 consisting primarily of Income Before Discontinued Operations of \$1.1 billion and \$1.5 billion of noncash depreciation and amortization. Other represents 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. Significant changes in other items resulted in lower cash from operations due to increased accounts receivable of \$113 million for new contracts in the generation and marketing segment and increased utility segment receivables and the CTC refunds in Texas.

Net Cash Flows from Operating Activities were approximately \$2.7 billion in 2006 consisting primarily of Income Before Discontinued Operations of \$992 million and \$1.5 billion of noncash depreciation and amortization. Under-recovered fuel costs decreased due to recoveries under proceedings we initiated in Oklahoma, Texas, Virginia and Arkansas during 2005. The Other category represents 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 most significant current period activity in these other items relates to a \$232 million decrease in cash related to customer deposits held for trading activities generally due to lower gas and power market prices.

Net Cash Flows from Operating Activities were approximately \$1.9 billion in 2005 consisting primarily of Income Before Discontinued Operations of \$787 million and \$1.3 billion of noncash depreciation and amortization. Other represents 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. We made contributions of \$626 million to our pension trusts. Under-recovered fuel costs increased due to the higher cost of fuel, especially natural gas. In 2005, we initiated fuel proceedings in Oklahoma, Texas, Virginia and Arkansas seeking recovery of our increased fuel costs. We also had a significant \$140 million cash increase from Accounts Payable due to higher fuel and allowance acquisition costs not paid at December 31, 2005 and an increase in Customer Deposits held for trading activities of \$157 million related to market prices.

Investing Activities

	Years Ended December 31,		
	2007	2006	2005
	(in millions)		
Construction Expenditures	\$ (3,556)	\$ (3,528)	\$ (2,404)
Acquisitions of Assets	(512)	-	(360)
Proceeds from Sales of Assets	222	186	1,606
Other	(75)	(401)	153
Net Cash Flows Used for Investing Activities	\$ (3,921)	\$ (3,743)	\$ (1,005)

Net Cash Flows Used for Investing Activities were \$3.9 billion in 2007 primarily due to Construction Expenditures for our environmental, distribution and new generation investment plan and purchases of gas-fired generating units. We funded our construction expenditures primarily with cash generated by operations and debt issuances.

Net Cash Flows Used for Investing Activities were \$3.7 billion in 2006 primarily due to Construction Expenditures for our environmental investment plan.

Net Cash Flows Used for Investing Activities were \$1 billion in 2005 primarily due to Construction Expenditures being partially offset by the proceeds from the sales of HPL and STP. The sales were part of an announced plan to divest noncore investments and assets and a requirement of collecting stranded costs in Texas. Construction Expenditures increased due to our environmental investment plan.

We forecast approximately \$3.8 billion of construction expenditures for 2008. 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, weather, legal reviews and the ability to access capital. These construction expenditures will be funded through results of operations and financing activities.

Financing Activities

	Years Ended December 31,		
	2007	2006	2005
		(in millions)	
Issuance/Repurchase of Common Stock, Net	\$ 144	\$ 99	\$ (25)
Issuance/Retirement of Debt, Net	1,902	1,420	(91)
Dividends Paid on Common Stock	(630)	(591)	(553)
Other	(6)	(17)	(122)
Net Cash Flows from (Used for) Financing Activities	\$ 1,410	\$ 911	\$ (791)

Net Cash Flows from Financing Activities were \$1.4 billion in 2007 primarily from issuance of debt to fund our construction program. We paid common stock dividends of \$630 million.

Net Cash Flows from Financing Activities were \$911 million in 2006 primarily from issuance of the Texas Securitization Bonds. We paid common stock dividends of \$591 million and issued and retired debt securities.

Net Cash Flows Used for Financing Activities were \$791 million in 2005 primarily from using cash to pay dividends, buy back stock, retire preferred stock and reduce debt.

The following financing activities occurred during 2007:

Common Stock:

- During 2007, we issued 3,751,968 shares of common stock under our incentive compensation and dividend reinvestment plans and received net proceeds of \$144 million.

Debt:

- During 2007, we issued approximately \$2.6 billion of long-term debt, including approximately \$304 million of pollution control revenue bonds at a weighted average interest rate of 4.78% and \$2.3 billion of senior notes at a weighted average interest rate of 6%. The proceeds from these issuances were used to fund long-term debt maturities and optional redemptions and construction programs. We also remarketed \$110 million of pollution control revenue bonds with new weighted average interest rates of 4.94% under the terms of their original issuance documents.
- During 2007, we entered into \$575 million of interest rate derivatives and settled \$597 million of such transactions. The settlements resulted in a net cash expenditure of \$6 million. As of December 31, 2007, we had in place interest rate derivatives designated as cash flow hedges with a notional amount of \$320 million in order to hedge risk exposure of variable interest rate debt.
- At December 31, 2007, we had credit facilities totaling \$3 billion to support our commercial paper program. As of December 31, 2007, we had \$659 million of commercial paper outstanding related to the corporate borrowing program. For the corporate borrowing program, the maximum amount of commercial paper outstanding during the year was \$865 million in August 2007 and the weighted average interest rate of commercial paper outstanding during the year was 5.54%.
- In 2008, we retired the following debt:
 - In January 2008, TCC retired \$74 million of its outstanding Securitization Bonds.
 - In February 2008, CSPCo retired \$52 million of 6.51% Senior Unsecured Notes at maturity.
 - In February 2008, TCC retired \$19 million of 7.125% First Mortgage Bonds at maturity.
- Our capital investment plans for 2008 will require additional funding from the capital markets.

Off-balance Sheet Arrangements

Under a limited set of circumstances, we enter into off-balance sheet arrangements for various reasons including accelerating cash collections, reducing operational expenses and spreading risk of loss to third parties. Our current 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. The following identifies significant off-balance sheet arrangements:

AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires from affiliated utilities to the commercial paper conduits and banks and receives cash. We have no ownership interest in the commercial paper conduits and, in accordance with GAAP, are not required to consolidate these entities. AEP Credit continues to service the receivables. This off-balance sheet transaction was entered to allow AEP Credit to repay its outstanding debt obligations, continue to purchase our operating companies' receivables and accelerate cash collections.

AEP Credit's sale of receivables agreement expires in October 2008. We intend to extend or replace the sale of receivables agreement. The sale of receivables agreement provides commitments of \$650 million to purchase receivables from AEP Credit. Under the agreement, the commitment increases to \$700 million for August and September to accommodate seasonal demand. At December 31, 2007, \$507 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. AEP Credit maintains an interest in the receivables sold and this interest is pledged as collateral for the collection of receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivables less an allowance for anticipated uncollectible accounts.

Rockport Plant Unit 2

AEGCo and I&M entered into a sale and leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and certain institutional investors. The future minimum lease payments for each company are \$1.1 billion as of December 31, 2007.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it to AEGCo and I&M. Our subsidiaries account for the lease as an operating lease with the future payment obligations included in Note 14. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. We, as well as our subsidiaries, have no ownership interest in the Owner Trustee and do not guarantee its debt.

Railcars

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 in 2008 for the full twenty years. This operating lease agreement allows us to avoid a large initial capital expenditure and to spread our railcar costs evenly over the expected twenty-year usage.

Under the return-and-sale option, the lessor is guaranteed that the sale proceeds will equal at least a specified lessee obligation amount which declines with each five year renewal. At December 31, 2007, the maximum potential loss was approximately \$30 million (\$20 million, net of tax) assuming the fair market value of the equipment is zero at the end of the current lease term. However, we believe that the fair market value would produce a sufficient sales price to avoid any loss.

We have other railcar lease arrangements that do not utilize this type of financing structure.

Summary Obligation Information

Our contractual obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in our footnotes. The following table summarizes our contractual cash obligations at December 31, 2007:

Payments Due by Period (in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Short-term Debt (a)	\$ 660	\$ -	\$ -	\$ -	\$ 660
Interest on Fixed Rate Portion of Long-term Debt (b)	708	1,303	1,130	6,122	9,263
Fixed Rate Portion of Long-term Debt (c)	636	1,726	1,087	9,320	12,769
Variable Rate Portion of Long-term Debt (d)	156	443	74	1,614	2,287
Capital Lease Obligations (e)	117	149	55	149	470
Noncancelable Operating Leases (e)	337	594	481	1,774	3,186
Fuel Purchase Contracts (f)	2,635	3,763	2,661	6,129	15,188
Energy and Capacity Purchase Contracts (g)	119	39	25	59	242
Construction Contracts for Capital Assets (h)	966	1,580	1,333	303	4,182
Total	\$ 6,334	\$ 9,597	\$ 6,846	\$ 25,470	\$ 48,247

- (a) Represents principal only excluding interest.
- (b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2007 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
- (c) See Note 15. Represents principal only excluding interest.
- (d) See Note 15. Represents principal only excluding interest. Variable rate debt had interest rates that ranged between 3.42% and 6.35% at December 31, 2007.
- (e) See Note 14.
- (f) Represents contractual obligations to purchase coal, natural gas and other consumables as fuel for electric generation along with related transportation of the fuel.
- (g) Represents contractual cash flows of energy and capacity purchase contracts.
- (h) Represents only capital assets that are contractual obligations.

Our FIN 48 liabilities of \$85 million are not included above because we cannot reasonably estimate the cash flows by period.

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

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. These commitments include standby letters of credit, guarantees for the payment of obligation performance bonds and other commitments. At December 31, 2007, our commitments outstanding under these agreements are summarized in the table below:

Amount of Commitment Expiration Per Period
(in millions)

Other Commercial Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Standby Letters of Credit (a) (b)	\$ 65	\$ -	\$ -	\$ -	\$ 65
Guarantees of the Performance of Outside Parties (b)	-	-	-	65	65
Guarantees of Our Performance (c)	691	1,224	23	75	2,013
Transmission Facilities for Third Parties (d)	12	1	-	-	13
Total Commercial Commitments	\$ 768	\$ 1,225	\$ 23	\$ 140	\$ 2,156

- (a) We issue standby letters of credit to third parties. These letters of credit, issued in our ordinary course of business, cover gas and electricity risk management contracts, construction contracts, insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. The maximum future payments of these letters of credit are \$65 million with maturities ranging from February 2008 to December 2008. As the parent of all of these subsidiaries, AEP holds all assets of the subsidiaries as collateral. There is no recourse to third parties if these letters of credit are drawn.
- (b) See “Guarantees of Third-party Obligations” section of Note 6.
- (c) We issued performance guarantees and indemnifications for energy trading, International Marine Terminal Pollution Control Bonds and various sale agreements.
- (d) As construction agent for third party owners of transmission facilities, we committed by contract terms to complete construction by dates specified in the contracts. Should we default on these obligations, financial payments could be required including liquidating damages of up to \$8 million and other remedies required by contract terms.

Other

Coal Contract Amendment

In January 2008, OPCo terminated a coal contract for deliveries of coal through 2012 and additional optional tonnage through 2017. The contracted prices were below current market prices. OPCo also entered into a new contract for reduced deliveries of comparable coal for 2009-2010, with an option for tonnage with firm pricing in 2011. Consideration received by OPCo for the significant tonnage reduction consisted of noncash consideration of approximately \$70 million. A significant portion of the consideration will be recognized in 2008 as a decrease to fuel expense. The remaining amount will be amortized to fuel expense as coal is delivered under the new contract in 2009-2010.

SIGNIFICANT FACTORS

Ohio Restructuring

As permitted by the current Ohio restructuring legislation, CSPCo and OPCo can implement market-based rates effective January 2009, following the expiration of their RSPs on December 31, 2008. The RSP plans include generation rates which are between cost and higher market rates. In August 2007, legislation was introduced that would significantly reduce the likelihood of CSPCo's and OPCo's ability to charge market-based rates for generation at the expiration of their RSPs. The Ohio Senate passed legislation and it is being considered by the Ohio House of Representatives. Management continues to analyze the proposed legislation and is working with various stakeholders to achieve a principled, fair and well-considered approach to electric supply pricing. At this time, management is unable to predict whether CSPCo and OPCo will transition to market pricing, extend their RSP rates, with or without modification, or become subject to a legislative reinstatement of some form of cost-based regulation for their generation supply business on January 1, 2009. The return to cost-based regulation could cause the generation business of CSPCo and OPCo, in whole or in part, to meet the criteria for application of SFAS 71. If CSPCo and OPCo are required to reestablish certain net regulatory liabilities applicable to their generation business, it could result in an extraordinary item and a decrease in future results of operations and financial condition.

Texas Restructuring

Pursuant to PUCT orders, TCC securitized its net recoverable stranded generation costs of \$2.5 billion and is recovering such costs over a period ending in 2020. TCC is also refunding its net other true-up items of \$375 million through 2008 via a CTC credit rate rider. TCC appealed the PUCT stranded costs true-up and related orders seeking relief in both state and federal court on the grounds that certain aspects of the orders are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law and fail to fully compensate TCC for its net stranded cost and other true-up items.

Municipal customers and other intervenors also appealed the PUCT true-up and related orders seeking to further reduce TCC's true-up recoveries. In March 2007, the Texas District Court judge hearing the appeal of the true-up order affirmed the PUCT's April 2006 final true-up order for TCC with two significant exceptions. The judge determined that the PUCT erred by applying an invalid rule to determine the carrying cost rate for the true-up of stranded costs. However, the District Court did not rule that the carrying cost rate was inappropriate. If the PUCT reevaluates the carrying cost rate on remand and reduces the rate, it could result in a material adverse change to TCC's recoverable carrying costs, results of operations, cash flows and financial condition.

The District Court judge also determined that the PUCT improperly reduced TCC's net stranded plant costs for commercial unreasonableness. If upheld on appeal, this ruling could have a materially favorable effect on TCC's results of operations and cash flows.

TCC, the PUCT and intervenors appealed the District Court decision to the Texas Court of Appeals. Management cannot predict the outcome of these court proceedings. If TCC ultimately succeeds in its appeals, it could have a favorable effect on future results of operations, cash flows and financial condition. If municipal customers and other intervenors succeed in their appeals, or if TCC has a tax normalization violation, it could have a substantial adverse effect on future results of operations, cash flows and financial condition.

Virginia Restructuring

In April 2007, the Virginia legislature adopted a comprehensive law providing for the re-regulation on a cost basis of electric utilities' generation and supply rates after the December 31, 2008 expiration of capped rates. The legislation provides for, among other things, biennial rate reviews beginning in 2009; rate adjustment clauses for the recovery of the costs of (a) transmission services and new transmission investments, (b) demand side management, load management, and energy efficiency programs, (c) renewable energy programs, and (d) environmental retrofit and new generation investments. It also provided for significant return on equity enhancements for investments in new generation and, subject to Virginia SCC approval, certain environmental retrofits, and a minimum allowed return on equity which will be based on the average earned return on equities of regional vertically integrated electric utilities. In addition, effective September 1, 2007, we are allowed to retain a minimum of 25% of the

margins from off-system sales with the remaining margins from such sales credited against fuel factor expenses with a true-up to actual. The legislation also allows APCo to continue to defer and recover incremental environmental and reliability costs incurred through December 31, 2008. The new legislation should result in significant positive effects on APCo's future earnings and cash flows resulting from the mandated enhanced future returns on equity, the reduction of regulatory lag from the opportunities to adjust base rates on a biennial basis and the new opportunities to request timely recovery of certain new costs not included in base rates.

Oklahoma 2007 Ice Storms

In October 2007, PSO filed with the OCC requesting recovery of \$13 million of operation and maintenance expenses related to service restoration efforts after a January 2007 ice storm. PSO proposed in its application to establish a regulatory asset of \$13 million and to amortize this asset coincident with gains from the sale of excess SO₂ allowances until such gains provide for the full recovery of the ice storm regulatory asset. In December 2007, PSO expensed approximately \$70 million of additional storm restoration costs related to a December 2007 ice storm.

In February 2008, PSO entered into a settlement with certain parties covering both ice storms and filed the settlement agreement with the OCC for approval. The settlement agreement provides for PSO to record a regulatory asset for actual ice storm operation and maintenance expenses, estimated to be \$83 million, less existing deferred gains from past sales of SO₂ emission allowances of \$11 million. The net regulatory asset will earn a return of 10.92% on the unrecovered balance. Under the settlement agreement, PSO will apply proceeds from future sales of excess SO₂ emission allowances of an estimated \$26 million to recover part of the ice storm regulatory asset. PSO will recover the remaining amount of the regulatory asset plus a return of 10.92% from customers over a period of five years beginning in the fourth quarter of 2008.

PJM Marginal Loss Pricing

In June 2007, in response to a 2006 FERC order, PJM revised its methodology for considering transmission line losses in generation dispatch and the calculation of locational marginal prices. Marginal-loss dispatch recognizes the varying delivery costs of transmitting electricity from individual generator locations to the places where customers consume the energy. Prior to the implementation of marginal-loss dispatch, PJM used average losses in dispatch and in the calculation of locational marginal prices. Locational marginal prices in PJM now include the real-time impact of transmission losses from individual sources to loads.

Due to the implementation of marginal-loss pricing, for the period June 1, 2007 through December 31, 2007, AEP experienced an increase of \$103 million in the cost of delivering energy from its generating plants to customer load zones. Management believes these additional costs should be recoverable through retail and/or cost-based wholesale rates and is deferring these incremental costs as regulatory assets where recovery is currently probable (Ohio, Virginia and West Virginia). We are also seeking recovery in Indiana and plan to seek recovery in Michigan and Kentucky. Beginning in 2008, we are deferring and/or collecting approximately 75% of these incremental PJM billings.

AEP has initiated discussions with PJM regarding the impact it is experiencing from the change in methodology and will pursue a modification of such methodology through the appropriate PJM stakeholder processes.

New Generation

AEP is in various stages of construction of the following generation facilities. Certain plants are pending regulatory approval:

Operating Company	Project Name	Location	Total Projected Cost (a) (in millions)	CWIP (b) (in millions)	Fuel Type	Plant Type	MW Capacity	Commercial Operation Date (Projected)
SWEPCo	Mattison	Arkansas	\$ 131 (c)	\$ -	Gas	Simple-cycle	340 (c)	2007
PSO	Southwestern	Oklahoma	58 (d)	51	Gas	Simple-cycle	170	2008
PSO	Riverside	Oklahoma	59 (d)	53	Gas	Simple-cycle	170	2008
AEGCo	Dresden (e)	Ohio	266 (e)	92	Gas	Combined-cycle	580	2010
SWEPCo	Stall	Louisiana	378	45	Gas	Combined-cycle	480	2010
SWEPCo	Turk (f)	Arkansas	1,300 (f)	272	Coal	Ultra-supercritical	600 (f)	2012
APCo	Mountaineer	West Virginia	2,230	-	Coal	IGCC	629	2012
CSPCo/OPCo	Great Bend	Ohio	2,700 (g)	-	Coal	IGCC	629	2017

(a) Amount excludes AFUDC.

(b) Amount includes AFUDC.

(c) Includes Units 3 and 4, 170 MW, declared in commercial operation on July 12, 2007 and Units 1 and 2, 170 MW, declared in commercial operations on December 28, 2007.

(d) In April 2007, the OCC authorized PSO to recover through a rider, subject to a \$135 million cost cap, all of the traditional costs associated with plant in service at the time these units are placed in service.

(e) In September 2007, AEGCo purchased the partially completed Dresden plant from Dresden Energy LLC, a subsidiary of Dominion Resources, Inc., for \$85 million, which is included in the "Total Projected Cost" section above.

(f) SWEPCo plans to own approximately 73%, or 438 MW, totaling about \$950 million in capital investment. See "Turk Plant" section below.

(g) Front-end engineering and design study is complete. Cost estimates, updated to reflect cost escalations due to revised commercial operation date of 2017, are not yet filed with the PUCO due to the pending appeals to the Supreme Court of Ohio resulting from the PUCO's April 2006 opinion and order. See "Ohio IGCC Plant" section of Note 4.

AEP acquired the following generation facilities in 2007:

Operating Company	Plant Name	Location	Cost (in millions)	Fuel Type	Plant Type	MW Capacity	Purchase Date
CSPCo	Darby (a)	Ohio	\$ 102	Gas	Simple-cycle	480	April 2007
AEGCo	Lawrenceburg (b)	Indiana	325	Gas	Combined-cycle	1,096	May 2007

(a) CSPCo purchased Darby Electric Generating Station (Darby) from DPL Energy, LLC, a subsidiary of The Dayton Power and Light Company.

(b) AEGCo purchased Lawrenceburg Generating Station (Lawrenceburg), adjacent to I&M's Tanners Creek Plant, from an affiliate of Public Service Enterprise Group (PSEG). AEGCo sells the power to CSPCo under a FERC-approved unit power agreement.

Turk Plant

In August 2006, SWEPCo announced plans to build a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas named the John W. Turk, Jr. (Turk) Plant. SWEPCo submitted filings with the APSC, the PUCT and the LPSC seeking approval of the plant. SWEPCo will own 73% of the Turk Plant and will operate the facility. During 2007, SWEPCo signed joint ownership agreements with Oklahoma Municipal Power Authority (OMPA), Arkansas Electric Cooperative Corporation (AECC) and East Texas Electric Cooperative (ETEC) for the remaining 27% of the Turk facility. The Turk Plant is estimated to cost \$1.3 billion with SWEPCo's portion estimated to cost \$950 million, excluding AFUDC. If approved on a timely basis, the plant is expected to be in-service in 2012. As of December 2007, SWEPCo capitalized approximately \$272 million of expenditures and has significant contractual commitments for an additional \$943 million.

In November 2007, the APSC granted approval to build the plant. Certain landowners filed a notice of appeal to the Arkansas State Court of Appeals. SWEPCo is still awaiting approvals from the Arkansas Department of Environmental Quality and the U.S. Army Corps of Engineers. Both approvals are anticipated to be received in the second or third quarter of 2008. The PUCT held hearings in October 2007. In January 2008, a Texas ALJ issued a report, which concluded that SWEPCo failed to prove there was a need for the plant. The Texas ALJ recommended

that SWEPCo's application be denied. The LPSC held hearings in September 2007 in which the LPSC staff expressed support for the project. In February 2008, a Louisiana ALJ issued a report which concluded that SWEPCo has demonstrated a need for additional capacity, and that a diversified fuel mix is an important attribute that should be taken into account in an overall strategic plan. The Louisiana ALJ recommended that SWEPCo's application be approved. SWEPCo expects decisions from the PUCT and the LPSC in the first half of 2008. If SWEPCo is not authorized to build the Turk plant, SWEPCo could incur significant cancellation fees to terminate its commitments and would be responsible to reimburse OMPA, AECC and ETEC for their share of costs. If that occurred, SWEPCo would seek recovery of its capitalized costs including any cancellation fees and joint owner reimbursements. If SWEPCo cannot recover its capitalized costs, it could have an adverse effect on future results of operations, cash flows and possibly financial condition.

Red Rock Generating Facility

In July 2006, PSO announced an agreement with Oklahoma Gas and Electric Company (OG&E) to build a 950 MW pulverized coal ultra-supercritical generating unit. PSO would own 50% of the new unit. Under the agreement OG&E would manage construction of the plant. OG&E and PSO requested preapproval to construct the Red Rock Generating Facility and to implement a recovery rider.

In October 2007, the OCC issued a final order approving PSO's need for 450 MWs of additional capacity by the year 2012, but denied PSO and OG&E's applications for construction preapproval. The OCC stated that PSO failed to fully study other alternatives. Since PSO and OG&E could not obtain preapproval to build the Red Rock Generating Facility, PSO and OG&E cancelled the third party construction contract and their joint venture development contract. PSO believes the Red Rock preconstruction costs, associated contract cancellation fees and applicable carrying costs are probable of recovery and established a regulatory asset for future recovery. In December 2007, PSO made a filing requesting recovery of the \$21 million regulatory asset that included associated carrying costs to date, and requested to recover future carrying costs at the weighted average cost of capital ordered in PSO's last rate case. In the filing, PSO proposed to amortize the asset commensurate with gains from the sale of excess SO₂ allowances until recovered. If a settlement agreement signed in February 2008 is approved, see the "Oklahoma 2007 Ice Storms" above, PSO will have to amend its Red Rock filing since the gains from the sale of excess SO₂ allowances originally expected to offset Red Rock costs are instead expected to be fully used to offset ice storm costs in accordance with the settlement. PSO continues to believe that the prudently incurred Red Rock preconstruction and cancellation costs will be recovered. If recovery becomes no longer probable or is denied, future results of operations and cash flows would be adversely affected by the reversal of the regulatory asset. As a result of the OCC's decision, PSO will restudy various alternative options to meet its capacity needs.

Electric Transmission Texas, LLC Joint Venture (Utility Operations Segment)

In December 2007, we received approval from the PUCT to establish Electric Transmission Texas, LLC (ETT), as a joint venture company to fund, own and operate electric transmission assets in ERCOT. The PUCT order also approved initial rates based on a 9.96% return on equity. In December 2007, AEP contributed \$70 million of TCC's transmission assets to ETT. Through a series of transactions, AEP then sold, at net book value, a 50% equity ownership interest in ETT to a subsidiary of MidAmerican Energy Holdings Company (MidAmerican). The use of a joint venture structure will allow us to share the significant capital requirements of the investments and to participate in more transmission projects than previously anticipated. ETT is not consolidated with AEP for financial reporting purposes. AEP provides services to ETT through service agreements.

ETT intends to invest in additional transmission projects in ERCOT over the next several years. Future projects will be evaluated on a case-by-case basis.

In February 2007, ETT filed a proposal with the PUCT that addresses the Competitive Renewable Energy Zone (CREZ) initiative of the Texas Legislature, which outlines opportunities for additional significant investment in transmission assets in Texas. The PUCT issued an interim order in August 2007 that directed ERCOT to perform studies by April 2008 to determine the necessary transmission upgrades to accommodate between 10,000 and 22,800 MW of wind development from CREZs across the Texas panhandle and central West Texas. The PUCT also indicated in its interim order that it plans to select transmission construction designees in the first quarter of 2008.

We believe Texas can provide a high degree of regulatory certainty for transmission investment due to the predetermination of ERCOT's need based on reliability requirements, significant Texas economic growth and public policy that supports "green generation" initiatives that require substantial transmission improvements. In addition, a streamlined annual interim transmission cost of service review process is available in ERCOT, which reduces regulatory lag.

Electric Transmission America, LLC (ETA) (Utilities Operations Segment)

In September 2007, AEP and MidAmerican formed ETA to pursue transmission opportunities outside of ERCOT. AEP holds a 50% equity ownership interest in ETA. ETA is not consolidated with AEP for financial reporting purposes. AEP provides services to ETA through service agreements.

Potomac-Appalachian Transmission Highline (PATH) (Utility Operations Segment)

In September 2007, AEP and Allegheny Energy Inc. (AYE) formed a joint venture by creating Potomac-Appalachian Transmission Highline, LLC and its subsidiaries (PATH). The PATH subsidiaries will operate as transmission utilities owning certain electric transmission assets within PJM. The ownership and management of the West Virginia facilities and the Ohio facilities within PATH will be shared 50/50 between AEP and AYE; other facilities within PATH are owned 100% by AYE. Both AEP and AYE provide services to the PATH companies through service agreements.

In December 2007, PATH filed an application with the FERC for approval of a transmission formula rate to recover its cost of service, including costs incurred prior to rates going into effect. PATH requested an incentive return of 14.3% and the inclusion of CWIP in rate base. The transmission formula rate will be collected from all PJM members. In addition to the rate recovery sought through the FERC, the PATH operating companies will seek regulatory approvals from the state utility commissions following completion of a routing study that is expected to occur in 2008. Management cannot predict the outcome of these proceedings.

PATH expects to invest approximately \$1.8 billion in new transmission facilities and AEP's estimated share will be approximately \$600 million. PATH will not be consolidated with AEP for financial reporting purposes.

Pension and Postretirement Benefit Plans

We maintain qualified, defined benefit pension plans (Qualified Plans), which cover a substantial majority of nonunion and certain union employees, and unfunded, nonqualified supplemental plans to provide benefits in excess of amounts permitted under the provisions of the tax law to be paid to participants in the Qualified Plans (collectively the Pension Plans). Additionally, we entered into individual retirement agreements with certain current and retired executives that provide additional retirement benefits as a part of the nonqualified, supplemental plans. We also sponsor other postretirement benefit plans to provide medical and life insurance benefits for retired employees (Postretirement Plans). The Pension Plans and Postretirement Plans are collectively the Plans.

The following table shows the net periodic cost for the Pension Plans and Postretirement Plans:

	Years Ended December 31,		
	2007	2006	2005
Net Periodic Benefit Cost		(in millions)	
Pension Plans	\$ 50	\$ 71	\$ 61
Postretirement Plans	81	96	109
Assumed Rate of Return			
Pension Plans	8.50%	8.50%	8.75%
Postretirement Plans	8.00%	8.00%	8.37%

The net periodic cost is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on the Plans' assets. In developing the expected long-term rate of return assumption for 2008, we evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. We also considered historical returns of the investment markets as well as our ten-year average return, for the period ended December 2007, of approximately 7.99%. We anticipate that the investment managers we employ for the Plans will generate future returns averaging 8.00%.

The expected long-term rate of return on the Plans' assets is based on our targeted asset allocation and our expected investment returns for each investment category. The investment returns for the Postretirement Plans are assumed to be slightly less than those of the Pension Plans as a portion of the returns for the Postretirement Plans is taxable. Our assumptions are summarized in the following table:

	Pension			Other Postretirement Benefit Plans		
	2007 Actual Asset Allocation	2008 Target Asset Allocation	Assumed/ Expected Long-term Rate of Return	2007 Actual Asset Allocation	2008 Target Asset Allocation	Assumed/ Expected Long-term Rate of Return
Equity	57%	55%	9.58%	62%	66%	9.05%
Real Estate	6%	5%	7.38%	-%	-%	-%
Debt Securities	36%	39%	6.00%	35%	33%	5.83%
Cash and Cash Equivalents	1%	1%	4.75%	3%	1%	3.65%
Total	100%	100%		100%	100%	

	2008 Pension	2008 Other Postretirement Benefit Plans
Overall Expected Return (weighted average)	8.00%	8.00%

We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation. Due to changes in our target allocation from year end 2006 to year end 2007, we continue to reallocate investments. We believe that 8.00% for the Pension Plans and Postretirement Plans is a reasonable long-term rate of return on the Plans' assets despite the recent market volatility. The Plans' assets had an actual gain of 9.21% and 12.78% for the twelve-months ended December 31, 2007 and 2006, respectively. We will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the assumptions as necessary.

We base our determination of pension expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2007, we had cumulative gains of approximately \$143 million that remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial gains will result in decreases in the future pension costs depending on several factors, including whether such gains at each measurement date exceed the corridor in accordance with SFAS No. 87, "Employers' Accounting for Pensions."

The method used to determine the discount rate that we utilize for determining future obligations is a duration-based method in which a hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's Aa bond index was constructed but with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio was used as the discount rate for the plan. The discount rate at December 31, 2007 under this method was 6.00% for the Pension Plans and 6.20% for the Postretirement Plans. Due to the effect of the unrecognized actuarial losses and based on an expected rate of return on the Pension Plans' assets of 8.00%, a discount rate of 6.00% and various other assumptions, we estimate that the pension costs for all pension plans will approximate \$33 million, \$22 million and \$21 million in 2008, 2009 and 2010, respectively. Based on an expected rate of return on the OPEB plans' assets of 8.00%, a discount rate of 6.20% and various other assumptions, we estimate Postretirement Plan costs will approximate \$73 million, \$70 million and \$69 million in 2008, 2009 and 2010, respectively. Future actual cost will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the Plans. The actuarial assumptions used may differ materially from actual results. The effects of a 50 basis point change to selective actuarial assumptions are included in "Pension and Other Postretirement Benefits" within the "Critical Accounting Estimates" section of this Management's Financial Discussion and Analysis of Results of Operations.

The value of the Pension Plans' assets increased to \$4.5 billion at December 31, 2007 from \$4.3 billion at December 31, 2006 primarily due to investment returns on the assets. The Qualified Plans paid \$277 million in benefits to plan participants during 2007 (nonqualified plans paid \$7 million in benefits). The value of our Postretirement Plans' assets increased to \$1.4 billion at December 31, 2007 from \$1.3 billion at December 31, 2006. The Postretirement Plans paid \$130 million in benefits to plan participants during 2007.

Our Qualified Plans remained fully funded as of December 31, 2007. Our nonqualified pension plans are unfunded, and are therefore considered underfunded for accounting purposes. For the nonqualified pension plans, the accumulated benefit obligation in excess of plan assets was \$77 million and \$78 million at December 31, 2007 and 2006, respectively.

Certain pension plans we sponsor and maintain contain a cash balance benefit feature. In recent years, cash balance benefit features have become a focus of scrutiny, as government regulators and courts consider how the Employee Retirement Income Security Act of 1974, as amended, the Age Discrimination in Employment Act of 1967, as amended, and other relevant federal employment laws apply to plans with such a cash balance plan feature. We believe that our defined benefit pension plans comply with the applicable requirements of such laws.

Investments within our Pension and Postretirement Plans' trusts have limited exposure to subprime mortgage markets at December 31, 2007.

Trust assets as of December 31, 2007 include approximately \$224 million in real estate and private equity investments in the pension fund that are illiquid and are valued based on appraisal or other methods requiring judgment.

The Pension Protection Act of 2006 did not materially impact our plans.

Litigation

In the ordinary course of business, we, along with 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 their eventual outcome 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 if the loss can be estimated. For details on our regulatory proceedings and pending litigation see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect our results of operations.

TEM Litigation

We agreed to sell up to approximately 800 MW of energy to Tractebel Energy Marketing, Inc. (TEM) for a period of 20 years under a Power Purchase and Sale Agreement (PPA). Beginning May 1, 2003, we tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as nonconforming. In 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. In January 2008, we reached a settlement with TEM to resolve all litigation regarding the PPA. TEM paid us \$255 million. We recorded the \$255 million as a gain in January 2008.

Environmental Litigation

New Source Review (NSR) Litigation: The Federal EPA, a number of states and certain special interest groups filed complaints alleging that APCo, CSPCo, I&M, and OPCo modified certain units at their coal-fired generating plants in violation of the NSR requirements of the CAA.

In December 2007, the U.S. District Court for the Southern District of Ohio approved our consent decree with the Federal EPA, the DOJ, the states and the special interest groups. Under the consent decree, we agreed to annual SO₂ and NO_x emission caps for sixteen coal-fired power plants located in Indiana, Kentucky, Ohio, Virginia and West

Virginia. In addition to completing the installation of previously announced environmental retrofit projects at many of the plants, we agreed to install selective catalytic reduction (SCR) and flue gas desulfurization (FGD or scrubbers) emissions control equipment on the Rockport Plant units.

Under the consent decree, we paid a \$15 million civil penalty in 2008 and provided \$36 million for environmental projects coordinated with the federal government and \$24 million to the states for environmental mitigation. We recognized these amounts in 2007. See “Federal EPA Complaint and Notice of Violation” section of Note 6.

Litigation continues against two plants CSPCo jointly-owns with Duke Energy Ohio, Inc. and Dayton Power and Light Company, which they operate. We are unable to predict the outcome of these cases. We believe we can recover any capital and operating costs of additional pollution control equipment that may be required through future regulated rates or 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 and cash flows.

Environmental Matters

We are implementing a substantial capital investment program and incurring 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; and
- Requirements under the Clean Water Act (CWA) to reduce the impacts of water intake structures on aquatic species at certain of our power plants.

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. We are also monitoring possible future requirements to reduce CO₂ and other greenhouse gases (GHG) emissions to address concerns about global climate change. All of these matters are discussed below.

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 described below. The states in which we operate, implement and administer many of these programs and could 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 safety margin. 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 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 submitted to the Federal EPA for approval. If a state fails to develop adequate plans, the Federal EPA develops and implements 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 adopted a new PM NAAQS in 2006, proposed a new ozone NAAQS in 2007 and is conducting periodic reviews for additional criteria pollutants.

In 1997, the Federal EPA established new PM and ozone NAAQS. In 2005, the Federal EPA issued a final rule, the Clean Air Interstate Rule (CAIR), that requires further reductions in SO₂ and NO_x emissions and assists states developing new SIPs to meet the 1997 NAAQS. CAIR reduces regional emissions of SO₂ and NO_x (which can be transformed into PM and ozone) from power plants in the Eastern U.S. (29 states and the District of Columbia). 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 rule has been challenged in the courts, but no decision has been issued. States were required to

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 and have or are developing CAIR SIPs. 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. The Federal EPA or the states may elect to seek further reductions of SO₂ and NO_x in the future in response to more stringent PM and ozone NAAQS.

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 2005, the Federal EPA issued a 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. States were required to develop and submit their SIPs to implement CAMR by November 2006.

Various states and special interest groups challenged the rule in the D.C. Circuit Court of Appeals. The Court ruled that the Federal EPA's action delisting fossil fuel-fired power plants did not conform to the procedures specified in the CAA, and vacated and remanded the federal rules for both new and existing coal-fired power plants to the Federal EPA. We are unable to predict how the Federal EPA will respond to the remand.

The Acid Rain Program: The 1990 Amendments to the CAA include a cap-and-trade emission reduction program for SO₂ emissions from power plants. By 2000, the program established a nationwide cap on power plant SO₂ emissions of 8.9 million tons per year. The 1990 Amendments also contain 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 continue to 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 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 of visibility in these areas (the "Regional Haze" program). In 2005, the Federal EPA issued its 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 CAIR will result in more visibility improvements than BART for power plants subject to it. 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 (Oklahoma, Texas and Arkansas of the AEP System) not subject to CAIR requirements for SO₂ and NO_x, some additional controls will be required. The courts upheld the final rule.

Estimated Air Quality Environmental Investments

The CAIR, CAVR and the consent decree signed to settle the NSR litigation require us to make significant additional investments, some of which are estimable. Our estimates 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 and their costs. In short, we cannot estimate our compliance costs with certainty and the actual costs to comply could differ significantly from the estimates discussed below.

By the end of 2007, we installed selective catalytic reduction (SCR) technology on over 11,375 MW of our eastern power plants to comply with NO_x emission requirements. We comply with SO₂ emission requirements by installing scrubbers and using alternate fuels and SO₂ allowances. We receive allowances through allocation and purchase at either the annual Federal EPA auction or in the market. Decreasing allowance allocations, our diminishing SO₂

allowance bank, increasing allowance costs, CAIR, CAVR and commitments in the consent decree will require installation of additional controls on our power plants through 2019. We plan to install additional scrubbers on 10,000 MW for SO₂ control. From 2008 to 2012, we estimate total environmental investment of \$3 billion including investment in scrubbers and other SO₂ equipment of approximately \$1.9 billion. These estimates may be revised as a result of the Court's decision remanding the CAMR. We will also incur additional operation and maintenance expenses in future years due to the costs associated with the maintenance of additional controls, disposal of byproducts and purchase of reagents.

Due to CAIR, CAMR and CAVR programs and the NSR settlement discussed above, we expect to incur additional costs for pollution control technology retrofits between 2013 and 2020 of approximately \$3 billion. However, this estimate is highly uncertain due to the variability associated with: (1) the states' implementation of these regulatory programs, including the potential for SIPs that impose standards more stringent than CAIR or CAMR, and the Court decision remanding the CAMR; (2) the actual performance of the pollution control technologies installed on our units; (3) changes in costs for new pollution controls; (4) new generating technology developments; and (5) other factors. Associated operational and maintenance expenses will also increase during those years. We cannot estimate these additional operational and maintenance costs due to the uncertainties described above, but they are expected to be significant.

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.

Clean Water Act Regulations

In 2004, the Federal EPA issued a final rule requiring all large existing power plants with once-through cooling water systems to meet certain standards to reduce mortality of aquatic organisms pinned against the plant's cooling water intake screen or entrained in the cooling water. The standards vary based on the water bodies from which the plants draw their cooling water. We expected additional capital and operating expenses, which the Federal EPA estimated could be \$193 million for our plants. We undertook site-specific studies and have been evaluating site-specific compliance or mitigation measures that could significantly change these cost estimates.

The rule was challenged and in January 2007, the Second Circuit Court of Appeals issued a decision remanding significant portions of the rule to the Federal EPA. In July 2007, the Federal EPA suspended the 2004 rule, except for the requirement that permitting agencies develop best professional judgment (BPJ) controls for existing facility cooling water intake structures that reflect the best technology available for minimizing adverse environmental impact. The result is that the BPJ control standard for cooling water intake structures in effect prior to the 2004 rule is the applicable standard for permitting agencies pending finalization of revised rules by the Federal EPA. We cannot predict further action of the Federal EPA or what effect it may have on similar requirements adopted by the states. We sought further review and filed for relief from the schedules included in our permits.

Potential Regulation of CO₂ and GHG Emissions

At the Third Conference of the Parties to the United Nations Framework Convention on Climate Change held in Kyoto, Japan in 1997, more than 160 countries, including the U.S., negotiated a treaty requiring legally-binding reductions in emissions of GHG. The U.S. signed the Kyoto Protocol in 1998, but the treaty was not submitted by President Clinton to the Senate for its consent. During 2004, enough countries ratified the treaty for it to become enforceable against the ratifying countries in February 2005. The first commitment period under the Kyoto Protocol ends in 2012.

Since 2005, several members of Congress have introduced bills seeking regulation of GHG emissions, including emissions from power plants. Congress has passed no legislation. We participate in a number of voluntary programs to monitor, mitigate, and reduce greenhouse gas emissions, including the Federal EPA's Climate Leaders program, the Department of Energy's GHG reporting program and the Chicago Climate Exchange. Through the end of 2006, we reduced our emissions by more than 39 million metric tons from levels in 1998-2001 as a result of these voluntary actions.

We support a reasonable approach to GHG emission reductions, including a mandate to achieve economy-wide reductions, that recognizes a reliable and affordable electric supply is vital to economic stability. We have taken measurable, voluntary actions to reduce and offset our GHG emissions. We believe that global warming is a global issue and that the United States should assume a leadership role in developing a new international approach that will address growing emissions from all nations, including developing countries such as India and China.

We, along with the International Brotherhood of Electrical Workers (IBEW), proposed that a consistent national policy for reasonable carbon controls should include the following principles:

- Comprehensiveness
- Cost-effectiveness
- Realistic emission reduction objectives
- Reliable monitoring and verification mechanisms
- Incentives to develop and deploy GHG reduction technologies
- Removal of regulatory or economic barriers to GHG emission reductions
- Recognition for early actions/investments in GHG reduction/mitigation
- Inclusion of adjustment provisions if largest emitters in developing world do not take action

In July 2007, we, along with several other utilities and labor unions, including the IBEW, announced support for the Low Carbon Economy Act of 2007. This legislation requires GHG reductions beginning in 2012 through an economy-wide cap-and-trade program. It contemplates reducing GHG emissions to their 2006 levels by 2020, and to their 1990 levels by 2030. Allowances to emit GHG would be allocated, auctioned or a combination of each, including a safety valve allowance price of \$12 per metric ton, subject to increasing adjustments. The legislation also includes incentives for other nations to adopt measures to limit GHG emissions. We endorse this legislation because it sets reasonable and achievable reduction targets and includes key elements of the AEP-IBEW principles.

The Bush administration sent representatives to the United Nations Framework Convention on Climate Change, held in Bali during December 2007. The Bali conference launched efforts designed to lead to a global pact on limiting GHG emissions after the Kyoto Protocol expires. Organizers anticipate two years of negotiation and hope to include the United States and developing economies, including China and India, in designing a successful global pact.

We expect that GHG emissions, including those associated with the operation of our fossil-fueled generating plants, will be limited by law or regulation in the future. The manner or timing of any such limitations cannot be predicted at this point. While we are exploring a number of alternatives, including the capture and storage of GHG emissions from new and existing power generation facilities, there is currently no demonstrated technology on a commercial scale that controls the emissions of GHG from fossil-fueled generating plants. Carbon capture and storage or other GHG limiting technology, if successfully demonstrated, is likely to have a material impact on the cost of operating our fossil-fueled generating plants. We will seek recovery of expenditures for potential regulation of GHG emissions from customers through our regulated rates and market prices of electricity.

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

The preparation of financial statements in accordance with GAAP requires us to make estimates and assumptions that affect reported amounts and related disclosures, including amounts related to legal matters and contingencies. We consider an accounting estimate to be critical if:

- It requires assumptions to be made that were uncertain at the time the estimate was made; and
- Changes in the estimate or different estimates that could have been selected could have a material effect on our consolidated results of operations or financial condition.

We discuss the development and selection of critical accounting estimates as presented below with the Audit Committee of AEP's Board of Directors and the Audit Committee reviews the disclosure relating to them.

We believe that the current assumptions and other considerations used to estimate amounts reflected in our consolidated financial statements are appropriate. However, actual results can differ significantly from those estimates.

The sections that follow present information about our most critical accounting estimates, as well as the effects of hypothetical changes in the material assumptions used to develop each estimate.

Regulatory Accounting

Nature of Estimates Required: Our consolidated financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated.

We recognize regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) for the economic effects of regulation. Specifically, we match the timing of our expense recognition with the recovery of such expense in regulated revenues. Likewise, we match income with the regulated revenues from our customers in the same accounting period. We also record regulatory liabilities for refunds, or probable refunds, to customers that have not been made.

Assumptions and Approach Used: When regulatory assets are probable of recovery through regulated rates, we record them as assets on the balance sheet. We review the probability of recovery whenever new events occur, for example, changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs, rate of return earned on invested capital and timing and amount of assets to be recovered through regulated rates. If recovery of a regulatory asset is no longer probable, we write-off that regulatory asset as a charge against earnings. A write-off of regulatory assets may also reduce future cash flows since there will be no recovery through regulated rates.

Effect if Different Assumptions Used: A change in the above assumptions may result in a material impact on our results of operations. Refer to Note 5 of the Notes to Consolidated Financial Statements for further detail related to regulatory assets and liabilities.

Revenue Recognition – Unbilled Revenues

Nature of Estimates Required: We record revenues when energy is delivered to the customer. The determination of sales to individual customers is based on the reading of their meters, which we perform on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue accrual is recorded. This estimate is reversed in the following month and actual revenue is recorded based on meter readings. In the Arkansas, Louisiana, Oklahoma and Texas jurisdictions and in accordance with the applicable state commission regulatory treatment, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

Incremental unbilled electric utility revenues included in Revenue on our Consolidated Statements of Income were \$47 million, \$(19) million and \$28 million for the years ended December 31, 2007, 2006 and 2005, respectively. Accrued unbilled revenues for the Utility Operations segment were \$376 million and \$329 million as of December 31, 2007 and 2006, respectively.

Assumptions and Approach Used: The operating company calculates the monthly estimate for unbilled revenues as net generation less the current month's billed KWH plus the prior month's unbilled KWH. However, due to the occurrence of problems in meter readings, meter drift and other anomalies, a separate monthly calculation limits the unbilled estimate within a range of values. This limiter calculation is derived from an allocation of billed KWH to the current month and previous month, on a cycle-by-cycle basis, and dividing the current month aggregated result by the billed KWH. The limits are statistically set at one standard deviation from this percentage to determine the upper and lower limits of the range. The unbilled estimate is compared to the limiter calculation and adjusted for variances exceeding the upper and lower limits.

Effect if Different Assumptions Used: Significant fluctuations in energy demand for the unbilled period, weather impact, line losses or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. A 1% change in the limiter calculation when it is outside the range would increase or decrease unbilled revenues by 1% of the accrued unbilled revenues on the Consolidated Balance Sheets.

Revenue Recognition – Accounting for Derivative Instruments

Nature of Estimates Required: We consider fair value techniques, valuation adjustments related to credit and liquidity, and judgments related to the probability of forecasted transactions occurring within the specified time period to be critical accounting estimates. These estimates are considered significant because they are highly susceptible to change from period to period and are dependent on many subjective factors.

Assumptions and Approach Used: We measure the fair values of derivative instruments and hedge instruments accounted for using MTM accounting based on exchange prices and broker quotes. If a quoted market price is not available, we estimate the fair value based on the best market information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data, and other assumptions. Fair value estimates, based upon the best market information available, involve uncertainties and matters of significant judgment. These uncertainties include projections of macroeconomic trends and future commodity prices, including supply and demand levels and future price volatility.

We reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. We calculate liquidity adjustments by utilizing future bid/ask spreads to estimate the potential fair value impact of liquidating open positions over a reasonable period of time. We base credit adjustments on estimated defaults by counterparties that are calculated using historical default probabilities for companies with similar credit ratings. We evaluate the probability of the occurrence of the forecasted transaction within the specified time period as provided in the original documentation related to hedge accounting.

Effect if Different Assumptions Used: There is inherent risk in valuation modeling given the complexity and volatility of energy markets. Therefore, it is possible that results in future periods may be materially different as contracts are ultimately settled.

The probability that hedged forecasted transactions will occur by the end of the specified time period could change operating results by requiring amounts currently classified in Accumulated Other Comprehensive Income (Loss) to be classified into operating income.

For additional information regarding accounting for derivative instruments, see sections labeled Credit Risk and VaR Associated with Risk Management Contracts within "Quantitative and Qualitative Disclosures About Risk Management Activities."

Long-Lived Assets

Nature of Estimates Required: In accordance with the requirements of SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," we evaluate long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable or the assets meet the held for sale criteria under SFAS 144. The evaluations of long-lived held and used assets may result from abandonments, significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as other economic or operations analyses. If the

carrying amount is not recoverable, we record an impairment to the extent that the fair value of the asset is less than its book value. For assets held for sale, an impairment is recognized if the expected net sales price is less than its book value. For regulated assets, an impairment charge could be offset by the establishment of a regulatory asset, if rate recovery is probable. For nonregulated assets, any impairment charge is recorded against earnings.

Assumptions and Approach Used: The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties, that is, other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, we estimate fair value using various internal and external valuation methods including cash flow projections or other market indicators of fair value such as bids received, comparable sales or independent appraisals. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

Effect if Different Assumptions Used: In connection with the evaluation of long-lived assets in accordance with the requirements of SFAS 144, the fair value of the asset can vary if different estimates and assumptions would have been used in our applied valuation techniques. In cases of impairment as described in Note 8 of the Notes to Consolidated Financial Statements, we made our best estimate of fair value using valuation methods based on the most current information at that time. We divested certain noncore assets and their sales values can vary from the recorded fair value as described in Note 8 of the Notes to Consolidated Financial Statements. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including, but not limited to, differences in subsequent market conditions, the level of bidder interest, timing and terms of the transactions and our analysis of the benefits of the transaction.

Pension and Other Postretirement Benefits

Nature of Estimates Required: We sponsor pension and other retirement and postretirement benefit plans in various forms covering all employees who meet eligibility requirements. We account for these benefits under SFAS 87, “Employers’ Accounting for Pensions”, SFAS 106, “Employers’ Accounting for Postretirement Benefits Other than Pensions” and SFAS 158. See Note 9 of the Notes to Consolidated Financial Statements for more information regarding costs and assumptions for employee retirement and postretirement benefits. The measurement of our pension and postretirement benefit obligations, costs and liabilities is dependent on a variety of assumptions.

Assumptions and Approach Used: The critical assumptions used in developing the required estimates include the following key factors:

- Discount rate
- Rate of compensation increase
- Cash balance crediting rate
- Health care cost trend rate
- Expected return on plan assets

Other assumptions, such as retirement, mortality, and turnover, are evaluated periodically and updated to reflect actual experience.

Effect if Different Assumptions Used: The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan participants. These differences may result in a significant impact to the amount of pension and postretirement benefit expense recorded. If a 50 basis point change were to occur for the following assumptions, the approximate effect on the financial statements would be as follows:

	Pension Plans		Other Postretirement Benefits Plans	
	+0.5%	-0.5%	+0.5%	-0.5%
(in millions)				
Effect on December 31, 2007 Benefit Obligations				
Discount Rate	\$ (177)	\$ 192	\$ (116)	\$ 124
Compensation Increase Rate	46	(41)	3	(3)
Cash Balance Crediting Rate	16	(15)	N/A	N/A
Health Care Cost Trend Rate	N/A	N/A	90	(79)
Effect on 2007 Periodic Cost				
Discount Rate	(15)	14	(11)	12
Compensation Increase Rate	9	(9)	1	(1)
Cash Balance Crediting Rate	7	(7)	N/A	N/A
Health Care Cost Trend Rate	N/A	N/A	16	(14)
Expected Return on Plan Assets	(21)	21	(6)	6

N/A = Not Applicable

Adoption of New Accounting Pronouncements

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. We adopted FIN 48 effective January 1, 2007. The effect of this interpretation on our financial statements was an unfavorable adjustment to retained earnings of \$17 million. See "FIN 48 "Accounting for Uncertainty in Income Taxes" and FASB Staff Position FIN 48-1 "Definition of Settlement in FASB Interpretation No. 48"" section of Note 2 and Note 13 – Income Taxes.

New Accounting Pronouncements

In September 2006, the FASB issued SFAS 157, enhancing existing guidance for fair value measurement of assets and liabilities and instruments measured at fair value that are classified in shareholders' equity. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures. It emphasizes that fair value is market-based with the highest measurement hierarchy level being market prices in active markets. The standard requires fair value measurements be disclosed by hierarchy level, an entity include its own credit standing in the measurement of its liabilities and modifies the transaction price presumption. The standard also nullifies the consensus reached in EITF Issue No. 02-3 "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-3) that prohibited the recognition of trading gains or losses at the inception of a derivative contract, unless the fair value of such derivative is supported by observable market data. In February 2008, the FASB issued FASB Staff Position (FSP) FAS 157-1 "Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13" which amends SFAS 157 to exclude SFAS 13 "Accounting for Leases" and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement under SFAS 13. In February 2008, the FASB issued FSP FAS 157-2 "Effective Date of FASB

Statement No. 157” which delays the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). The provision of SFAS 157 are applied prospectively, except for a) changes in fair value measurements of existing derivative financial instruments measured initially using the transaction price under EITF 02-3, b) existing hybrid financial instruments measured initially at fair value using the transaction price, and c) blockage discount factors. Although the statement is applied prospectively upon adoption, in accordance with the provisions of SFAS 157 related to EITF 02-3, we recorded an immaterial transition adjustment to beginning retained earnings. The impact of considering our own credit risk when measuring the fair value of liabilities, including derivatives, had an immaterial impact on fair value measurements upon adoption. We partially adopted SFAS 157 effective January 1, 2008. We will adopt SFAS 157 effective January 1, 2009 for items within the scope of FSP FAS 157-2.

In February 2007, the FASB issued SFAS 159, permitting entities to choose to measure many financial instruments and certain other items at fair value. The standard also establishes presentation and disclosure requirements designed to facilitate comparison between entities that choose different measurement attributes for similar types of assets and liabilities. If the fair value option is elected, the effect of the first remeasurement to fair value is reported as a cumulative effect adjustment to the opening balance of retained earnings. The statement is applied prospectively upon adoption. We adopted SFAS 159 effective January 1, 2008. At adoption, we did not elect the fair value option for any assets or liabilities.

In April 2007, the FASB issued FSP FIN 39-1. It amends FASB Interpretation No. 39 “Offsetting of Amounts Related to Certain Contracts” by replacing the interpretation’s definition of contracts with the definition of derivative instruments per SFAS 133. It also requires entities that offset fair values of derivatives with the same party under a netting agreement to net the fair values (or approximate fair values) of related cash collateral. The entities must disclose whether or not they offset fair values of derivatives and related cash collateral and amounts recognized for cash collateral payables and receivables at the end of each reporting period. This standard changed our method of netting certain balance sheet amounts and reduced assets and liabilities by an immaterial amount. It requires retrospective application as a change in accounting principle for all periods presented. We adopted FIN 39-1 effective January 1, 2008.

In March 2007, the FASB ratified EITF 06-10, a consensus on collateral assignment split-dollar life insurance arrangements in which an employee owns and controls the insurance policy. Under EITF 06-10, an employer should recognize a liability for the postretirement benefit related to a collateral assignment split-dollar life insurance arrangement in accordance with SFAS 106 “Employers’ Accounting for Postretirement Benefits Other Than Pension” or Accounting Principles Board Opinion No. 12 “Omnibus Opinion – 1967” if the employer has agreed to maintain a life insurance policy during the employee’s retirement or to provide the employee with a death benefit based on a substantive arrangement with the employee. In addition, an employer should recognize and measure an asset based on the nature and substance of the collateral assignment split-dollar life insurance arrangement. EITF 06-10 requires recognition of the effects of its application as either (a) a change in accounting principle through a cumulative effect adjustment to retained earnings or other components of equity or net assets in the statement of financial position at the beginning of the year of adoption or (b) a change in accounting principle through retrospective application to all prior periods. We adopted EITF 06-10 effective January 1, 2008 with an immaterial effect on our financial statements.

In June 2007, the FASB ratified EITF 06-11, a consensus on the treatment of income tax benefits of dividends on employee share-based compensation. The issue is how a company should recognize the income tax benefit received on dividends that are paid to employees holding equity-classified nonvested shares, equity-classified nonvested share units or equity-classified outstanding share options and charged to retained earnings under SFAS 123R, “Share-Based Payments.” Under EITF 06-11, a realized income tax benefit from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for equity-classified nonvested equity shares, nonvested equity share units and outstanding equity share options should be recognized as an increase to additional paid-in capital. EITF 06-11 was applied prospectively to the income tax benefits of dividends on equity-classified employee share-based payment awards when declared. The adoption of this standard had an immaterial impact on our financial statements. We adopted EITF 06-11 effective January 1, 2008.

In December 2007, the FASB issued SFAS 141R, improving financial reporting about business combinations and their effects. It establishes how the acquiring entity recognizes and measures the identifiable assets acquired, liabilities assumed, goodwill acquired, any gain on bargain purchases and any noncontrolling interest in the acquired entity. SFAS 141R no longer allows acquisition-related costs to be included in the cost of the business combination, but rather expensed in the periods they are incurred, with the exception of the costs to issue debt or equity securities which shall be recognized in accordance with other applicable GAAP. SFAS 141R requires disclosure of information for a business combination that occurs during the accounting period or prior to the issuance of the financial statements for the accounting period. SFAS 141R is effective prospectively for business combinations with an acquisition date on or after the beginning of the first annual reporting period after December 15, 2008. Early adoption is prohibited. We will adopt SFAS 141R effective January 1, 2009 and apply it to any business combinations on or after that date.

In December 2007, the FASB issued SFAS 160, modifying reporting for noncontrolling interest (minority interest) in consolidated financial statements. It requires noncontrolling interest be reported in equity and establishes a new framework for recognizing net income or loss and comprehensive income by the controlling interest. Upon deconsolidation due to loss of control over a subsidiary, the standard requires a fair value remeasurement of any remaining noncontrolling equity investment to be used to properly recognize the gain or loss. SFAS 160 requires specific disclosures regarding changes in equity interest of both the controlling and noncontrolling parties and presentation of the noncontrolling equity balance and income or loss for all periods presented. SFAS 160 is effective for interim and annual periods in fiscal years beginning after December 15, 2008. The statement is applied prospectively upon adoption. Early adoption is prohibited. Upon adoption, prior period financial statements will be restated for the presentation of the noncontrolling interest for comparability. Although we have not completed our analysis, we expect that the adoption of this standard will have an immaterial impact on our financial statements. We will adopt SFAS 160 effective January 1, 2009.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our Utility Operations segment is exposed to certain market risks as a major power producer and marketer of wholesale electricity, coal and emission allowances. 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 used 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 Generation and Marketing segment, operating primarily within ERCOT, transacts in wholesale energy trading and marketing contracts. This segment is exposed to certain market risks as a marketer of wholesale electricity. These risks include commodity price risk, interest rate risk and credit risk. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

All Other includes natural gas operations which holds forward natural gas contracts that were not sold with the natural 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 and financial forward purchase and sale contracts. We engage in risk management of electricity, natural 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 determined by the commercial operations group in accordance with the market risk policy approved by the Finance Committee of our Board of Directors. Our market risk oversight staff independently monitors our risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (CORC) various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. The CORC consists of our President – AEP Utilities, Chief Financial Officer, Senior Vice President of Commercial Operations and Chief Risk Officer. When commercial activities exceed predetermined limits, we modify the positions to reduce the risk to be within the limits unless specifically approved by the CORC.

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 adopted disclosure standards for risk management contracts to improve clarity, understanding and consistency of information reported. We support the work of the CCRO and embrace 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 on our balance sheet as of December 31, 2007 and the reasons for changes in our total MTM value included on our balance sheet as compared to December 31, 2006.

Reconciliation of MTM Risk Management Contracts to Consolidated Balance Sheet December 31, 2007 (in millions)

	Utility Operations	Generation and Marketing	All Other	Sub-Total MTM Risk Management Contracts	PLUS: MTM of Cash Flow and Fair Value Hedges	Total
Current Assets	\$ 171	\$ 47	\$ 61	\$ 279	\$ 7	\$ 286
Noncurrent Assets	184	84	70	338	2	340
Total Assets	355	131	131	617	9	626
Current Liabilities	(116)	(60)	(63)	(239)	(11)	(250)
Noncurrent Liabilities	(83)	(28)	(76)	(187)	(2)	(189)
Total Liabilities	(199)	(88)	(139)	(426)	(13)	(439)
Total MTM Derivative Contract Net Assets (Liabilities)	\$ 156	\$ 43	\$ (8)	\$ 191	\$ (4)	\$ 187

MTM Risk Management Contract Net Assets (Liabilities) Year Ended December 31, 2007 (in millions)

	Utility Operations	Generation and Marketing	All Other	Total
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2006	\$ 236	\$ 2	\$ (5)	\$ 233
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(116)	(1)	(2)	(119)
Fair Value of New Contracts at Inception When Entered During the Period (a)	6	59	-	65
Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered During The Period	2	-	-	2
Changes in Fair Value due to Market Fluctuations During the Period (b)	8	(17)	(1)	(10)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	20	-	-	20
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2007	\$ 156	\$ 43	\$ (8)	191
Net Cash Flow and Fair Value Hedge Contracts				(4)
Ending Net Risk Management Assets at December 31, 2007				\$ 187

- (a) Reflects fair value on long-term contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.
- (b) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
- (c) "Change in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected on the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities for those subsidiaries that operate in regulated jurisdictions.

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, to give an indication of when these MTM amounts will settle and generate cash.

Maturity and Source of Fair Value of MTM Risk Management Contract Net Assets (Liabilities) Fair Value of Contracts as of December 31, 2007 (in millions)

	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>	<u>2012</u>	<u>After 2012 (c)</u>	<u>Total</u>
Utility Operations:							
Prices Actively Quoted – Exchange							
Traded Contracts	\$ (13)	\$ 6	\$ 4	\$ -	\$ -	\$ -	\$ (3)
Prices Provided by Other External							
Sources – OTC Broker Quotes (a)	73	43	31	4	-	-	151
Prices Based on Models and Other							
Valuation Methods (b)	(5)	3	1	3	6	-	8
Total	<u>55</u>	<u>52</u>	<u>36</u>	<u>7</u>	<u>6</u>	<u>-</u>	<u>156</u>
Generation and Marketing:							
Prices Actively Quoted – Exchange							
Traded Contracts	4	1	-	-	-	-	5
Prices Provided by Other External							
Sources – OTC Broker Quotes (a)	(16)	2	11	-	-	-	(3)
Prices Based on Models and Other							
Valuation Methods (b)	(1)	(1)	(1)	11	11	22	41
Total	<u>(13)</u>	<u>2</u>	<u>10</u>	<u>11</u>	<u>11</u>	<u>22</u>	<u>43</u>
All Other:							
Prices Actively Quoted – Exchange							
Traded Contracts	-	-	-	-	-	-	-
Prices Provided by Other External							
Sources – OTC Broker Quotes (a)	(2)	(4)	-	-	-	-	(6)
Prices Based on Models and Other							
Valuation Methods (b)	-	-	(4)	2	-	-	(2)
Total	<u>(2)</u>	<u>(4)</u>	<u>(4)</u>	<u>2</u>	<u>-</u>	<u>-</u>	<u>(8)</u>
Total:							
Prices Actively Quoted – Exchange							
Traded Contracts	(9)	7	4	-	-	-	2
Prices Provided by Other External							
Sources – OTC Broker Quotes (a)	55	41	42	4	-	-	142
Prices Based on Models and Other							
Valuation Methods (b)	(6)	2	(4)	16	17	22	47
Total	<u>\$ 40</u>	<u>\$ 50</u>	<u>\$ 42</u>	<u>\$ 20</u>	<u>\$ 17</u>	<u>\$ 22</u>	<u>\$ 191</u>

- (a) Prices Provided by Other External Sources - OTC Broker Quotes reflects information obtained from over-the-counter brokers (OTC), industry services, or multiple-party online platforms.
- (b) Prices Based on Models and Other Valuation Methods is used in the absence of independent 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 including values determinable by other third party transactions.
- (c) There is mark-to-market value of \$22 million in individual periods beyond 2012. \$8 million of this mark-to-market value is in 2013, \$7 million is in 2014, \$3 million is in 2015, \$2 million is in 2016 and \$2 million is in 2017.

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
December 31, 2007**

Commodity	Transaction Class	Market/Region	Tenor (in Months)
Natural Gas	Futures	NYMEX / Henry Hub	60
	Physical Forwards	Gulf Coast, Texas	24
	Swaps	Northeast, Mid-Continent, Gulf Coast, Texas	24
	Exchange Option Volatility	NYMEX / Henry Hub	12
Power	Futures	AEP East - PJM	36
	Physical Forwards	AEP East - Cinergy	48
	Physical Forwards	AEP - PJM West	48
	Physical Forwards	AEP - Dayton (PJM)	48
	Physical Forwards	AEP - ERCOT	36
	Physical Forwards	AEP - Entergy	24
	Physical Forwards	Power West – PV, NP15, SP15, MidC, Mead	36
	Peak Power Volatility (Options)	AEP East - Cinergy, PJM	12
Emissions	Credits	SO ₂ , NO _x	48
Coal	Physical Forwards	PRB, NYMEX, CSX	36

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

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

We use interest rate derivative transactions to manage interest rate risk related to 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.

We use foreign currency derivatives to lock in prices on certain transactions denominated in foreign currencies where deemed necessary, and designate qualifying instruments as cash flow hedge strategies. 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 Consolidated Balance Sheets and the reasons for changes in cash flow hedges from December 31, 2006 to December 31, 2007. 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 cash flow hedges are recorded in AOCI. Therefore, economic hedge contracts which 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
Year Ended December 31, 2007
(in millions)

	Power	Interest Rate and Foreign Currency	Total
Beginning Balance in AOCI, December 31, 2006	\$ 17	\$ (23)	\$ (6)
Changes in Fair Value	(1)	(4)	(5)
Reclassifications from AOCI to Net Income for Cash Flow Hedges Settled	(17)	2	(15)
Ending Balance in AOCI, December 31, 2007	<u>\$ (1)</u>	<u>\$ (25)</u>	<u>\$ (26)</u>
 After Tax Portion Expected to be Reclassified to Earnings During Next 12 Months	 <u>\$ (2)</u>	 <u>\$ (3)</u>	 <u>\$ (5)</u>

Credit Risk

We limit credit risk in our wholesale 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 meets 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 parent/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 December 31, 2007, our credit exposure net of credit collateral to sub investment grade counterparties was approximately 5.4%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of December 31, 2007, 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% of Net Exposure	Net Exposure of Counterparties >10%
Investment Grade	\$ 540	\$ 32	\$ 508	-	\$ -
Split Rating	16	2	14	2	11
Noninvestment Grade	19	5	14	1	15
No External Ratings:					
Internal Investment Grade	75	-	75	1	34
Internal Noninvestment Grade	23	3	20	2	14
Total as of December 31, 2007	<u>\$ 673</u>	<u>\$ 42</u>	<u>\$ 631</u>	<u>6</u>	<u>\$ 74</u>
 Total as of December 31, 2006	 <u>\$ 998</u>	 <u>\$ 161</u>	 <u>\$ 837</u>	 <u>9</u>	 <u>\$ 169</u>

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, 2010. 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 December 31, 2007

	<u>2008</u>	<u>2009</u>	<u>2010</u>
Estimated Plant Output Hedged	89%	92%	91%

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates Value at Risk (VaR) to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at December 31, 2007, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

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

VaR Model

December 31, 2007				December 31, 2006			
(in millions)				(in millions)			
<u>End</u>	<u>High</u>	<u>Average</u>	<u>Low</u>	<u>End</u>	<u>High</u>	<u>Average</u>	<u>Low</u>
\$1	\$6	\$2	\$1	\$3	\$10	\$3	\$1

We back-test our VaR results against performance due to actual price moves. Based on the assumed 95% confidence interval, the performance due to actual price moves would be expected to exceed the VaR at least once every 20 trading days. Our backtesting results show that our actual performance exceeded VaR far fewer than once every 20 trading days. As a result, we believe our VaR calculation is conservative.

As our VaR calculation captures recent price moves, we also perform regular stress testing of the portfolio to understand our exposure to extreme price moves. We employ a historically-based method whereby the current portfolio is subjected to actual, observed price moves from the last three years in order to ascertain which historical price moves translates into the largest potential mark-to-market loss. We can then research the underlying positions, price moves and market event that created the most significant exposure.

Interest Rate Risk

We utilize an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which AEP's interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. For 2008, the estimated EaR on our debt portfolio was \$15 million.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of American Electric Power Company, Inc.:

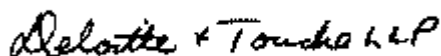
We have audited the accompanying consolidated balance sheets of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2007 and 2006, and the related consolidated statements of income, changes in common shareholders' equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of American Electric Power Company, Inc. and subsidiary companies as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes," effective January 1, 2007. As discussed in Note 9 to the consolidated financial statements, the Company adopted FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans," effective December 31, 2006. As discussed in Note 17 to the consolidated financial statements, the Company adopted FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations," effective December 31, 2005.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2008 expressed an unqualified opinion on the Company's internal control over financial reporting.



Columbus, Ohio
February 28, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of American Electric Power Company, Inc.:

We have audited the internal control over financial reporting of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2007, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2007 of the Company and our report dated February 28, 2008 expressed an unqualified opinion on those consolidated financial statements and included an explanatory paragraph concerning the Company's adoption of a new accounting pronouncement in 2007.

Deloitte & Touche LLP

Columbus, Ohio
February 28, 2008

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of American Electric Power Company, Inc. and subsidiary companies (AEP) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15 (f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. AEP's internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

AEP management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2007. In making this assessment we used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control- Integrated Framework. Based on our assessment, the Company's internal control over financial reporting was effective as of December 31, 2007.

AEP's independent registered public accounting firm has issued an attestation report on the Company's internal control over financial reporting. The Report of Independent Registered Public Accounting Firm appears on the previous page.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2007, 2006 and 2005
(in millions, except per-share and share amounts)

REVENUES	2007	2006	2005
Utility Operations	\$ 12,101	\$ 12,066	\$ 11,157
Other	1,279	556	954
TOTAL	13,380	12,622	12,111
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	3,829	3,817	3,592
Purchased Energy and Gas for Resale	1,138	856	943
Other Operation and Maintenance	3,867	3,639	3,619
Gain on Disposition of Assets, Net	(41)	(69)	(120)
Asset Impairments and Other Related Charges	-	209	39
Depreciation and Amortization	1,513	1,467	1,348
Taxes Other Than Income Taxes	755	737	763
TOTAL	11,061	10,656	10,184
OPERATING INCOME	2,319	1,966	1,927
Interest and Investment Income	51	99	105
Carrying Costs Income	51	114	55
Allowance for Equity Funds Used During Construction	33	30	21
Investment Value Losses	-	-	(7)
Gain on Disposition of Equity Investments, Net	47	3	56
INTEREST AND OTHER CHARGES			
Interest Expense	841	732	697
Preferred Stock Dividend Requirements of Subsidiaries	3	3	7
TOTAL	844	735	704
INCOME BEFORE INCOME TAX EXPENSE, MINORITY INTEREST EXPENSE AND EQUITY EARNINGS	1,657	1,477	1,453
Income Tax Expense	516	485	430
Minority Interest Expense	3	3	4
Equity Earnings of Unconsolidated Subsidiaries	6	3	10
INCOME BEFORE DISCONTINUED OPERATIONS, EXTRAORDINARY LOSS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	1,144	992	1,029
DISCONTINUED OPERATIONS, NET OF TAX	24	10	27
INCOME BEFORE EXTRAORDINARY LOSS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	1,168	1,002	1,056
EXTRAORDINARY LOSS, NET OF TAX	(79)	-	(225)
CUMULATIVE EFFECT OF ACCOUNTING CHANGE, NET OF TAX	-	-	(17)
NET INCOME	\$ 1,089	\$ 1,002	\$ 814
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING	398,784,745	394,219,523	389,969,636
BASIC EARNINGS (LOSS) PER SHARE			
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	\$ 2.87	\$ 2.52	\$ 2.64
Discontinued Operations, Net of Tax	0.06	0.02	0.07
Income Before Extraordinary Loss and Cumulative Effect of Accounting Change	2.93	2.54	2.71
Extraordinary Loss, Net of Tax	(0.20)	-	(0.58)
Cumulative Effect of Accounting Change, Net of Tax	-	-	(0.04)
TOTAL BASIC EARNINGS PER SHARE	\$ 2.73	\$ 2.54	\$ 2.09
WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING	400,198,799	396,483,464	391,423,842
DILUTED EARNINGS (LOSS) PER SHARE			
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	\$ 2.86	\$ 2.50	\$ 2.63
Discontinued Operations, Net of Tax	0.06	0.03	0.07
Income Before Extraordinary Loss and Cumulative Effect of Accounting Change	2.92	2.53	2.70
Extraordinary Loss, Net of Tax	(0.20)	-	(0.58)
Cumulative Effect of Accounting Change, Net of Tax	-	-	(0.04)
TOTAL DILUTED EARNINGS PER SHARE	\$ 2.72	\$ 2.53	\$ 2.08
CASH DIVIDENDS PAID PER SHARE	\$ 1.58	\$ 1.50	\$ 1.42

See Notes to Consolidated Financial Statements.

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

ASSETS

December 31, 2007 and 2006
(in millions)

	<u>2007</u>	<u>2006</u>
CURRENT ASSETS		
Cash and Cash Equivalents	\$ 178	\$ 301
Other Temporary Investments	365	425
Accounts Receivable:		
Customers	730	676
Accrued Unbilled Revenues	379	350
Miscellaneous	60	44
Allowance for Uncollectible Accounts	(52)	(30)
Total Accounts Receivable	<u>1,117</u>	<u>1,040</u>
Fuel, Materials and Supplies	967	913
Risk Management Assets	286	680
Margin Deposits	58	120
Prepayments and Other	81	109
TOTAL	<u>3,052</u>	<u>3,588</u>
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	20,233	16,787
Transmission	7,392	7,018
Distribution	12,056	11,338
Other (including coal mining and nuclear fuel)	3,445	3,405
Construction Work in Progress	3,019	3,473
Total	<u>46,145</u>	<u>42,021</u>
Accumulated Depreciation and Amortization	16,275	15,240
TOTAL - NET	<u>29,870</u>	<u>26,781</u>
OTHER NONCURRENT ASSETS		
Regulatory Assets	2,199	2,477
Securitized Transition Assets	2,108	2,158
Spent Nuclear Fuel and Decommissioning Trusts	1,347	1,248
Goodwill	76	76
Long-term Risk Management Assets	340	378
Employee Benefits and Pension Assets	486	327
Deferred Charges and Other	888	910
TOTAL	<u>7,444</u>	<u>7,574</u>
Assets Held for Sale	<u>-</u>	<u>44</u>
TOTAL ASSETS	<u>\$ 40,366</u>	<u>\$ 37,987</u>

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2007 and 2006

	2007	2006
	(in millions)	
CURRENT LIABILITIES		
Accounts Payable	\$ 1,324	\$ 1,360
Short-term Debt	660	18
Long-term Debt Due Within One Year	792	1,269
Risk Management Liabilities	250	541
Customer Deposits	337	339
Accrued Taxes	601	781
Accrued Interest	235	186
Other	1,008	962
TOTAL	5,207	5,456
NONCURRENT LIABILITIES		
Long-term Debt	14,202	12,429
Long-term Risk Management Liabilities	189	260
Deferred Income Taxes	4,730	4,690
Regulatory Liabilities and Deferred Investment Tax Credits	2,952	2,910
Asset Retirement Obligations	1,075	1,023
Employee Benefits and Pension Obligations	712	823
Deferred Gain on Sale and Leaseback – Rockport Plant Unit 2	139	148
Deferred Credits and Other	1,020	775
TOTAL	25,019	23,058
TOTAL LIABILITIES	30,226	28,514
Cumulative Preferred Stock Not Subject to Mandatory Redemption	61	61
Commitments and Contingencies (Note 6)		
COMMON SHAREHOLDERS' EQUITY		
Common Stock Par Value \$6.50:		
	2007	2006
Shares Authorized	600,000,000	600,000,000
Shares Issued	421,926,696	418,174,728
(21,499,992 shares were held in treasury at December 31, 2007 and 2006, respectively)	2,743	2,718
Paid-in Capital	4,352	4,221
Retained Earnings	3,138	2,696
Accumulated Other Comprehensive Income (Loss)	(154)	(223)
TOTAL	10,079	9,412
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	\$ 40,366	\$ 37,987

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2007, 2006 and 2005
(in millions)

	2007	2006	2005
OPERATING ACTIVITIES			
Net Income	\$ 1,089	\$ 1,002	\$ 814
Less: Discontinued Operations, Net of Tax	(24)	(10)	(27)
Income Before Discontinued Operations	1,065	992	787
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	1,513	1,467	1,348
Deferred Income Taxes	76	24	65
Deferred Investment Tax Credits	(24)	(29)	(32)
Cumulative Effect of Accounting Changes, Net of Tax	-	-	17
Extraordinary Loss, Net of Tax	79	-	225
Asset Impairments, Investment Value Losses and Other Related Charges	-	209	46
Carrying Costs Income	(51)	(114)	(55)
Allowance for Equity Funds Used During Construction	(33)	(30)	(21)
Mark-to-Market of Risk Management Contracts	42	(37)	84
Amortization of Nuclear Fuel	65	50	56
Pension Contributions to Qualified Plan Trusts	-	-	(626)
Deferred Property Taxes	(26)	(14)	(17)
Fuel Over/Under-Recovery, Net	(117)	182	(239)
Gain on Sales of Assets and Equity Investments, Net	(88)	(72)	(176)
Change in Noncurrent Liability for NSR Settlement	58	-	-
Change in Other Noncurrent Assets	(98)	15	(94)
Change in Other Noncurrent Liabilities	90	28	67
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(113)	177	(7)
Fuel, Materials and Supplies	16	(187)	(20)
Margin Deposits	62	101	(108)
Accounts Payable	(21)	56	140
Customer Deposits	(2)	(232)	157
Accrued Taxes	(90)	128	48
Other Current Assets	(11)	17	52
Other Current Liabilities	(4)	1	180
Net Cash Flows from Operating Activities	2,388	2,732	1,877
INVESTING ACTIVITIES			
Construction Expenditures	(3,556)	(3,528)	(2,404)
Change in Other Temporary Investments, Net	(114)	(33)	76
Purchases of Investment Securities	(11,086)	(18,359)	(8,836)
Sales of Investment Securities	11,213	18,080	8,934
Acquisitions of Assets	(512)	-	(360)
Proceeds from Sales of Assets	222	186	1,606
Other	(88)	(89)	(21)
Net Cash Flows Used for Investing Activities	(3,921)	(3,743)	(1,005)
FINANCING ACTIVITIES			
Issuance of Common Stock	144	99	402
Repurchase of Common Stock	-	-	(427)
Issuance of Long-term Debt	2,546	3,359	2,651
Change in Short-term Debt, Net	642	7	(13)
Retirement of Long-term Debt	(1,286)	(1,946)	(2,729)
Proceeds from Nuclear Fuel Sale/Leaseback	85	-	-
Principal Payments for Capital Lease Obligations	(67)	(63)	(56)
Dividends Paid on Common Stock	(630)	(591)	(553)
Other	(24)	46	(66)
Net Cash Flows from (Used for) Financing Activities	1,410	911	(791)
Net Increase (Decrease) in Cash and Cash Equivalents	(123)	(100)	81
Cash and Cash Equivalents at Beginning of Period	301	401	320
Cash and Cash Equivalents at End of Period	\$ 178	\$ 301	\$ 401

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDERS' EQUITY AND
COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2007, 2006, and 2005
(in millions)

	<u>Common Stock</u>				<u>Accumulated</u>	
	<u>Shares</u>	<u>Amount</u>	<u>Paid-in</u>	<u>Retained</u>	<u>Other</u>	<u>Total</u>
			<u>Capital</u>	<u>Earnings</u>	<u>Comprehensive</u>	
					<u>Income (Loss)</u>	
DECEMBER 31, 2004	405	\$ 2,632	\$ 4,203	\$ 2,024	\$ (344)	\$ 8,515
Issuance of Common Stock	10	67	335			402
Common Stock Dividends				(553)		(553)
Repurchase of Common Stock			(427)			(427)
Other			20			20
TOTAL						<u>7,957</u>
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Taxes:						
Foreign Currency Translation Adjustments, Net of Tax of \$0					(6)	(6)
Cash Flow Hedges, Net of Tax of \$15					(27)	(27)
Securities Available for Sale, Net of Tax of \$11					20	20
Minimum Pension Liability, Net of Tax of \$175					330	330
NET INCOME				814		<u>814</u>
TOTAL COMPREHENSIVE INCOME						<u>1,131</u>
DECEMBER 31, 2005	415	2,699	4,131	2,285	(27)	9,088
Issuance of Common Stock	3	19	80			99
Common Stock Dividends				(591)		(591)
Other			10			10
TOTAL						<u>8,606</u>
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Taxes:						
Cash Flow Hedges, Net of Tax of \$11					21	21
Securities Available for Sale, Net of Tax of \$0					(1)	(1)
Minimum Pension Liability, Net of Tax of \$1					2	2
NET INCOME				1,002		<u>1,002</u>
TOTAL COMPREHENSIVE INCOME						<u>1,024</u>
Minimum Pension Liability Elimination, Net of Tax of \$9					17	17
SFAS 158 Adoption, Net of Tax of \$126					(235)	(235)
DECEMBER 31, 2006	418	2,718	4,221	2,696	(223)	9,412
FIN 48 Adoption, Net of Tax				(17)		(17)
Issuance of Common Stock	4	25	119			144
Common Stock Dividends				(630)		(630)
Other			12			12
TOTAL						<u>8,921</u>
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Taxes:						
Cash Flow Hedges, Net of Tax of \$10					(20)	(20)
Securities Available for Sale, Net of Tax of \$1					(1)	(1)
SFAS 158 Adoption Costs Established as a Regulatory Asset for the Reapplication of SFAS 71, Net of Tax of \$6					11	11
Pension and OPEB Funded Status, Net of Tax of \$42					79	79
NET INCOME				1,089		<u>1,089</u>
TOTAL COMPREHENSIVE INCOME						<u>1,158</u>
DECEMBER 31, 2007	422	\$ 2,743	\$ 4,352	\$ 3,138	\$ (154)	\$ 10,079

See Notes to Consolidated Financial Statements.

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

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

The principal business conducted by nine of our electric utility operating companies is the generation, transmission and distribution of electric power. Pursuant to the Texas Restructuring Legislation, TCC and TNC have completed the final stage of exiting the generation business and along with WPCo and KGPCo provide only transmission and distribution services. AEGCo is a regulated electricity generation business whose function is to provide power to our regulated electric utility operating companies. These companies are subject to regulation by the FERC under the Federal Power Act and the Energy Policy Act of 2005. These companies maintain accounts in accordance with the FERC and other regulatory guidelines. These companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

We also engage in wholesale electricity, natural gas and other commodity marketing and risk management activities in the United States. In addition, our operations include nonregulated wind farms, coal mining and barging operations and we provide various energy-related services.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

All of our affiliated transactions are regulated by the FERC under the 2005 Public Utility Holding Company Act (2005 PUHCA), including intercompany activity with our service company, AEPSC. Our public utility subsidiaries' rates are regulated by the FERC and state regulatory commissions in our eleven state operating territories. The state regulatory commissions with jurisdiction approve the retail rates charged and regulate the retail services and operations of the utility subsidiaries for the generation and supply of power, a majority of transmission energy delivery services and distribution services.

The FERC regulates wholesale power markets and wholesale power transactions. Our wholesale power transactions are generally market-based and are not cost-based regulated unless we negotiate and file a cost-based contract with the FERC or the FERC determines that we have "market power" in the region in which the transaction is taking place. We enter into wholesale all-requirements power supply contracts with various municipalities and cooperatives that are FERC-regulated, cost-based contracts. Our wholesale power transactions in the SPP region are all cost-based due to our market power in the SPP region. As of December 31, 2007, SWEPCo and PSO operate in the SPP region.

The FERC also regulates, on a cost basis, our wholesale transmission service and rates except in Texas. The FERC claimed jurisdiction over retail transmission rates when the retail rates are unbundled in connection with restructuring. CSPCo's and OPCo's rates in Ohio and APCo's retail rates in Virginia are unbundled. Therefore, our retail transmission rates are based on FERC's Open Access Transmission Tariff (OATT) rates that are cost-based. Although our retail rates are unbundled in Texas, retail transmission rates are still regulated, on a cost basis, by the state regulatory commission.

In addition, FERC regulates the SIA, the AEP Power Pool, the CSW Operating Agreement, the System Transmission Integration Agreement, the Transmission Equalization Agreement, the Transmission Coordination Agreement and the System Interim Allowance Agreement, all of which allocate shared system costs and revenues to the AEP utility subsidiaries that are parties to the agreements.

The state regulatory commissions regulate all of our retail public utility services/operations (generation/power supply, transmission and distribution operations) and rates except in Ohio and the ERCOT region of Texas. Our retail generation/power supply operations and rates for CSPCo and OPCo in Ohio are no longer cost-based regulated and are on a transition to market-based rates. These rates are currently subject to rate stabilization plans which expire on December 31, 2008. Under the present legislation in Ohio, rates are scheduled to be market-based starting in January 2009. However, legislation is under consideration that may extend that transition date. In the ERCOT

region of Texas, the generation/supply business is under customer choice and market pricing. AEP has no Texas jurisdictional retail generation/power supply operations other than a minor supply operation through a commercial and industrial customer REP. In Virginia, the legislature re-regulated AEP's generation/supply business in 2007 ending a transition to market-based rates and returning APCo to cost-based regulation. See Note 4 for further information on restructuring legislation and its effects on AEP in Ohio, Texas, Virginia and Michigan.

In 2005, we were subject to regulation by the SEC under the Public Utility Holding Company Act of 1935 (1935 PUHCA). The Energy Policy Act of 2005 repealed the 1935 PUHCA effective February 8, 2006 and replaced it with the 2005 PUHCA. With the repeal of the 1935 PUHCA, the SEC no longer has jurisdiction over the affiliated activities of registered holding companies, their respective service corporations and their intercompany transactions, which it regulated since 1935 predominantly at cost. Jurisdiction over holding company-related affiliated activities was transferred to the FERC and the required reporting was reduced by the 2005 PUHCA. The FERC also has jurisdiction over the issuances and acquisitions of securities of our public utility subsidiaries, the acquisition or sale of certain utility assets, mergers with another electric utility or holding company, intercompany transactions, accounting and AEPSC intercompany service billings which are generally at cost. The intercompany sale of non-power goods and non-AEPSC services to affiliates cannot exceed market under the 2005 PUHCA. The state regulatory commissions in Virginia and West Virginia also regulate certain intercompany transactions under their affiliates statutes.

Both the FERC and state regulatory commissions with jurisdiction are permitted to review and audit the books and records of any company within a public utility holding company system.

Principles of Consolidation

Our consolidated financial statements include AEP and its wholly-owned and majority-owned subsidiaries consolidated with their wholly-owned subsidiaries or substantially-controlled variable interest entities (VIEs). Intercompany items are eliminated in consolidation. Equity investments not substantially-controlled that are 50% or less owned are accounted for using the equity method of accounting and report them as Deferred Charges and Other on our Consolidated Balance Sheets; equity earnings are included in Equity Earnings of Unconsolidated Subsidiaries on our Consolidated Statements of Income. We also have generating units that are jointly-owned with nonaffiliated companies. Our proportionate share of the operating costs associated with such facilities is included on our Consolidated Statements of Income and our proportionate share of the assets and liabilities are reflected on our Consolidated Balance Sheets.

Accounting for the Effects of Cost-Based Regulation

As the owner of cost-based rate-regulated electric public utility companies, our consolidated financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with SFAS 71, regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues and income with its passage to customers through the reduction of regulated revenues. Due to the commencement of legislatively-required restructuring and a transition to customer choice and market-based rates, we discontinued the application of SFAS 71, regulatory accounting, for the generation portion of our business: in Ohio for OPCo and CSPCo in September 2000, in Virginia for APCo in June 2000 and in Texas for TCC, TNC and the Texas portion of SWEPCo in September 1999. In 2007, the Virginia legislature amended its restructuring legislation to provide for the re-regulation of generation and supply rates on a cost basis. SFAS 101, "Regulated Enterprises – Accounting for the Discontinuance of Application of FASB Statement No. 71" requires the recognition of an impairment of stranded regulatory assets and stranded plant costs if they are not recoverable in regulated rates. In addition, an enterprise is required to eliminate from its balance sheet the effects of any actions of regulators that had been recognized as regulatory assets and regulatory liabilities pursuant to SFAS 71. Such impairments and adjustments arising from the discontinuance or reapplication of SFAS 71 are classified by SFAS 101 as an extraordinary item. TCC recorded extraordinary impairment losses related to its regulatory assets and plant costs in 2005 resulting from the discontinuance of cost-based regulation of their generation business without full recovery of the resultant stranded costs. Consistent with SFAS 71 as amended by SFAS 101, APCo recorded an extraordinary reduction in earnings and shareholder's equity from the reapplication of SFAS 71 regulatory accounting in 2007 resulting from the re-regulation of their generation and supply rates on a cost basis.

Use of Estimates

The preparation of these financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include, but are not limited to, inventory valuation, allowance for doubtful accounts, goodwill, intangible and long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Property, Plant and Equipment and Equity Investments

Electric utility property, plant and equipment are stated at original purchase cost. Property, plant and equipment of nonregulated operations and other equity investments (included in Deferred Charges and Other) are stated at fair market value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Additions, major replacements and betterments are added to the plant accounts. For the Utility Operations segment, normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for both cost-based rate-regulated and most nonregulated operations under the group composite method of depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in the original cost, less salvage, being charged to accumulated depreciation. For the nonregulated generation assets, a gain or loss would be recorded if the retirement is not considered an interim routine replacement. The depreciation rates that are established for the generating plants take into account the past history of interim capital replacements and the amount of salvage received. These rates and the related lives are subject to periodic review. Gains and losses are recorded for any retirements in the MEMCO Operations and Generation and Marketing segments. Removal costs are charged to regulatory liabilities for cost-based rate-regulated operations and charged to expense for nonregulated operations. The costs of labor, materials and overhead incurred to operate and maintain our plants are included in operating expenses.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held for sale criteria under SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." Equity investments are required to be tested for impairment when it is determined there may be an other than temporary loss in value.

The fair value of an asset or investment is the amount at which that asset or investment could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets or investments in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that are capitalized and recovered through depreciation over the service life of domestic regulated electric utility plant. For nonregulated operations, including domestic generating assets in Ohio and Texas, effective with the discontinuance of SFAS 71 regulatory accounting, interest is capitalized during construction in accordance with SFAS 34, "Capitalization of Interest Costs."

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Accounts Receivable, Short-term Debt and Accounts Payable approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability approximates the best estimate of its fair value.

Cash and Cash Equivalents

Cash and Cash Equivalents include temporary cash investments with original maturities of three months or less.

Other Temporary Investments

Other Temporary Investments include marketable securities that we intend to hold for less than one year and funds held by trustees primarily for the payment of debt.

We classify our investments in marketable securities as available-for-sale or held-to-maturity in accordance with the provisions of SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities" (SFAS 115). We do not have any investments classified as trading.

Available-for-sale securities reflected in Other Temporary Investments are carried at fair value with the unrealized gain or loss, net of tax, reported in other comprehensive income. Held-to-maturity securities reflected in Other Temporary Investments are carried at amortized cost. The cost of securities sold is based on the specific identification or weighted average cost method. The fair value of most investment securities is determined by currently available market prices. Where quoted market prices are not available, we use the market price of similar types of securities that are traded in the market to estimate fair value.

The following is a summary of Other Temporary Investments:

	December 31,							
	2007		2006		2007		2006	
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
Other Temporary Investments	(in millions)							
Cash (a)	\$ 273	\$ -	\$ -	\$ 273	\$ 138	\$ -	\$ -	\$ 138
Debt Securities	66	-	-	66	258	-	-	258
Corporate Equity Securities	-	26	-	26	1	28	-	29
Total Other Temporary Investments	\$ 339	\$ 26	\$ -	\$ 365	\$ 397	\$ 28	\$ -	\$ 425

(a) Primarily represents amounts held for the payment of debt.

Proceeds from sales of current available-for-sale securities were \$10.5 billion, \$17.4 billion and \$8.2 billion in 2007, 2006 and 2005, respectively. Purchases of current available-for-sale securities were \$10.3 billion, \$17.7 billion and \$8.1 billion in 2007, 2006 and 2005, respectively. Gross realized gains from the sale of current available-for-sale securities were \$16 million, \$39 million and \$47 million in 2007, 2006 and 2005, respectively. Gross realized losses from the sale of current available-for-sale securities were not material in 2007, 2006 or 2005.

The fair value of debt securities, summarized by contractual maturities, at December 31, 2007 is as follows:

Maturity	Fair Value of Debt Securities (in millions)
2008	\$ -
2009 – 2012	-
2013 – 2017	-
After 2017	66
Total	\$ 66

Inventory

Fossil fuel inventories are generally carried at average cost. Materials and supplies inventories are carried at average cost.

Accounts Receivable

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to our risk management activities and customer receivables primarily related to other revenue-generating activities.

We recognize revenue from electric power and gas sales when we deliver power or gas to our customers. To the extent that deliveries have occurred but a bill has not been issued, we accrue and recognize, as Accrued Unbilled Revenues on our Consolidated Balance Sheets, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable for certain subsidiaries, including CSPCo, I&M, KGPCo, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia regulatory jurisdiction, only a portion of APCo's accounts receivable are sold to AEP Credit. AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," allowing the receivables to be removed from the company's balance sheet (see "Sale of Receivables – AEP Credit" section of Note 15).

Deferred Fuel Costs

The cost of fuel and related chemical and emission allowance consumables is charged to Fuel and Other Consumables Used for Electric Generation Expense when the fuel is burned or the consumable is utilized. Where applicable under governing state regulatory commission retail rate orders, fuel cost over-recoveries (the excess of fuel revenues billed to customers over fuel costs incurred) are deferred as current regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to customers) are deferred as current regulatory assets. These deferrals are amortized when refunded or when billed to customers in later months with the regulator's review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of regulators. On a routine basis, state regulatory commissions audit our fuel cost calculations. When a fuel cost disallowance becomes probable, we adjust our deferrals and record provisions for estimated refunds to recognize these probable outcomes (see Note 4). Fuel cost over-recovery and under-recovery balances are classified as noncurrent when the fuel clauses have been suspended or terminated as in West Virginia (prior to July 2006) and Texas-ERCOT, respectively.

In general, changes in fuel costs in Kentucky for KPCo, Indiana (beginning July 1, 2007) and Michigan for I&M, the SPP area of Texas, Louisiana and Arkansas for SWEPCo, Oklahoma for PSO, Virginia and West Virginia (beginning July 1, 2006) for APCo are reflected in rates in a timely manner through the fuel cost adjustment clauses in place in those states. All or a portion of profits from off-system sales are shared with customers through fuel

clauses in Texas (SPP area only), Oklahoma, Louisiana, Arkansas, Kentucky, West Virginia (beginning July 1, 2006), Virginia (beginning September 1, 2007) and in some areas of Michigan. Where fuel clauses have been eliminated due to the transition to market pricing (Ohio effective January 1, 2001), changes in fuel costs impact earnings unless recovered in the sales price for electricity. In other state jurisdictions (prior to July 1, 2007 in Indiana and prior to July 1, 2006 in West Virginia), where fuel clauses were capped, frozen or suspended for a period of years, fuel costs impacted earnings. Deferred fuel accounting for over- or under-recovery began July 1, 2006 in West Virginia and July 1, 2007 in Indiana.

Revenue Recognition

Regulatory Accounting

Our consolidated financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period and by matching income with its passage to customers in cost-based regulated rates. Regulatory liabilities or regulatory assets are also recorded for unrealized MTM gains or losses that occur due to changes in the fair value of physical and/or financial contracts that are derivatives and that are subject to the regulated ratemaking process when realized.

When regulatory assets are probable of recovery through regulated rates, we record them as assets on our Consolidated Balance Sheets. We test for probability of recovery whenever new events occur. One example includes the issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against earnings.

Traditional Electricity Supply and Delivery Activities

Revenues are recognized from retail and wholesale electricity supply sales and electricity transmission and distribution delivery services. We recognize the revenues on our Consolidated Statements of Income upon delivery of the energy to the customer and include unbilled as well as billed amounts. In accordance with the applicable state commission regulatory treatment, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

Most of the power produced at the generation plants of the AEP East companies is sold to PJM, the RTO operating in the east service territory, and we purchase power back from the same RTO to supply power to our load. These power sales and purchases are reported on a net basis as revenues on our Consolidated Statements of Income. Other RTOs in which we operate do not function in the same manner as PJM. They function as balancing organizations and not as an exchange.

Physical energy purchases, including those from all RTOs, that are identified as non-trading, but excluding PJM purchases described in the preceding paragraph, are accounted for on a gross basis in Purchased Energy and Gas for Resale on our Consolidated Statements of Income.

In general, we record expenses when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting where generation/supply rates are not cost-based regulated, such as in Ohio and the ERCOT portion of Texas. In jurisdictions where the generation/supply business is subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

For power purchased under derivative contracts in our west zone where we are short capacity, we recognize as revenues the unrealized gains and losses (other than those subject to regulatory deferral) that result from measuring these contracts at fair value during the period before settlement. If the contract results in the physical delivery of power from a RTO or any other counterparty, we reverse the previously recorded unrealized gains and losses from MTM valuations and record the settled amounts gross as Purchased Energy and Gas for Resale. If the contract does not result in physical delivery, we reverse the previously recorded unrealized gains and losses from MTM valuations and record the settled amounts as Revenues on our Consolidated Statements of Income on a net basis (see "Derivatives and Hedging" section of Note 12).

Domestic Gas Pipeline and Storage Activities

As a result of the sale of HPL in 2005, our domestic gas pipeline and storage activities ceased. Prior to the sale of HPL, we recognized revenues from domestic gas pipeline and storage services when gas was delivered to contractual meter points or when services were provided, with the exception of certain physical forward gas purchase-and-sale contracts that were derivatives and accounted for using MTM accounting (resale gas contracts). The unrealized and realized gains and losses on resale gas contracts for the sale of natural gas are presented as Revenues on our Consolidated Statements of Income. The unrealized and realized gains and losses on physically-settled resale gas contracts for the purchase of natural gas are presented as Purchased Energy and Gas for Resale on our Consolidated Statements of Income.

Energy Marketing and Risk Management Activities

We engage in wholesale electricity, natural gas, coal and emission allowances marketing and risk management activities focused on wholesale markets where we own assets. Our activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts, which include exchange traded futures and options and over-the-counter options and swaps. We engage in certain energy marketing and risk management transactions with RTOs.

We recognize revenues and expenses from wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. We use MTM accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or as a normal purchase or sale. We include the unrealized and realized gains and losses on wholesale marketing and risk management transactions that are accounted for using MTM in Revenues on our Consolidated Statements of Income on a net basis. In jurisdictions subject to cost-based regulation, we defer the unrealized MTM amounts as regulatory assets (for losses) and regulatory liabilities (for gains). We include unrealized MTM gains and losses resulting from derivative contracts on our Consolidated Balance Sheets as Risk Management Assets or Liabilities as appropriate.

Certain qualifying wholesale marketing and risk management derivative transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). We initially record the effective portion of the cash flow hedge's gain or loss as a component of Accumulated Other Comprehensive Income (Loss). When the forecasted transaction is realized and affects earnings, we subsequently reclassify the gain or loss on the hedge from Accumulated Other Comprehensive Income into revenues or expenses on our Consolidated Statements of Income, within the same financial statement line item as the forecasted transaction. We recognize the ineffective portion of the gain or loss in revenues or expense, depending on the specific nature of the associated hedged risk, on our Consolidated Statements of Income immediately, except in those jurisdictions subject to cost-based regulation. In those regulated jurisdictions we defer the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains) (see "Cash Flow Hedging Strategies" section of Note 12).

Barging Activities

MEMCO Operations' revenue is recognized based on percentage of voyage completion. The proportion of freight transportation revenue to be recognized is determined by applying a percentage to the contractual charges for such services. The percentage is determined by dividing the number of miles from the loading point to the position of the barge as of the end of the accounting period by the total miles to the destination specified in the customer's freight contract. The position of the barge at accounting period end is determined by MEMCO's computerized barge tracking system.

Construction Projects for Outside Parties

We engage in construction projects for outside parties and account for the projects on the percentage-of-completion method of revenue recognition. This method recognizes revenue, including the related margin, as we incur project costs.

Maintenance

We expense maintenance costs as incurred. If it becomes probable that we will recover specifically-incurred costs through future rates, we establish a regulatory asset to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues. We defer maintenance costs during refueling outages at the Cook Plant and amortize the costs over the period between outages in accordance with rate orders in Indiana and Michigan. We also defer tree trimming costs for PSO and amortize the costs commensurate with recovery through a rate rider in Oklahoma.

Income Taxes and Investment Tax Credits

We use the liability method of accounting for income taxes. Under the liability method, we provide deferred income taxes for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence.

When the flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), we record deferred income taxes and establish related regulatory assets and liabilities to match the regulated revenues and tax expense.

We account for investment tax credits under the flow-through method except where regulatory commissions reflect investment tax credits in the rate-making process on a deferral basis. We amortize deferred investment tax credits over the life of the plant investment.

We account for uncertain tax positions in accordance with FIN 48. Effective with the adoption of FIN 48, we classify interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classify penalties as Other Operation and Maintenance.

Excise Taxes

We act as an agent for some state and local governments and collect from customers certain excise taxes levied by those state or local governments on our customers. We do not recognize these taxes as revenue or expense.

Debt and Preferred Stock

We defer gains and losses from the reacquisition of debt used to finance domestic regulated electric utility plants and amortize the deferral over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If we refinance the reacquired debt associated with the regulated business, the reacquisition costs attributable to the portions of the business subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. Some jurisdictions require that these costs be expensed upon reacquisition. We report gains and losses on the reacquisition of debt for operations not subject to cost-based rate regulation in Interest Expense on our Consolidated Statements of Income.

We defer debt discount or premium and debt issuance expenses and amortize generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations. We include the amortization expense in Interest Expense on our Consolidated Statements of Income.

Where reflected in rates, we include redemption premiums paid to reacquire preferred stock of certain domestic utility subsidiaries in paid-in capital and amortize the premiums to retained earnings commensurate with recovery in rates. We credit the excess of par value over costs of preferred stock reacquired to paid-in capital and reclassify the excess to retained earnings upon the redemption of the entire preferred stock series. We credit the excess of par value over the costs of reacquired preferred stock for nonregulated subsidiaries to retained earnings upon reacquisition.

Goodwill and Intangible Assets

When we acquire businesses, we record the fair value of all assets and liabilities, including intangible assets. To the extent that consideration exceeds the fair value of identified assets, we record goodwill. We do not amortize goodwill and intangible assets with indefinite lives. We test acquired goodwill and other intangible assets with indefinite lives for impairment at least annually at their estimated fair value. We test goodwill at the reporting unit level and other intangibles at the asset level. Fair value is the amount at which an asset or liability could be bought or sold in a current transaction between willing parties, that is, other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, we estimate fair value using various internal and external valuation methods. We amortize intangible assets with finite lives over their respective estimated lives, currently ranging from 5 to 10 years, to their estimated residual values. We also review the lives of the amortizable intangibles with finite lives on an annual basis.

Emission Allowances

We record emission allowances at cost, including the annual SO₂ and NO_x emission allowance entitlements received at no cost from the Federal EPA. We follow the inventory model for all allowances. We record allowances expected to be consumed within one year in Fuel, Materials and Supplies and allowances with expected consumption beyond one year in Other Noncurrent Assets – Deferred Charges and Other on our Consolidated Balance Sheets. We record the consumption of allowances in the production of energy in Fuel and Other Consumables Used for Electric Generation on our Consolidated Statements of Income at an average cost. We record allowances held for speculation in Current Assets – Prepayments and Other on our Consolidated Balance Sheets. We report the purchases and sales of allowances in the Operating Activities section of the Statements of Cash Flows. We record the net margin on sales of emission allowances in Utility Operations Revenue on our Consolidated Statements of Income because of its integral nature to the production process of energy and our revenue optimization strategy for our utility operations. The net margin on sales of emission allowances affects the determination of deferred fuel costs and the amortization of regulatory assets for certain jurisdictions.

Nuclear Trust Funds

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions allow us to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above when purchased).
- Maximum percentage invested in a specific type of investment.
- Prohibition of investment in obligations of AEP or its affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.

We maintain trust funds for each regulatory jurisdiction. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification, and other prudent investment objectives.

We record securities held in these trust funds as Spent Nuclear Fuel and Decommissioning Trusts on our Consolidated Balance Sheets. We record these securities at market value. We classify securities in the trust funds as available-for-sale due to their long-term purpose. Upon the issuance of FASB Staff Position 115-1 and 124-1 “The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments,” we consider all nuclear decommissioning trust fund and spent nuclear fuel trust fund investments in unrealized loss positions to be other-than-temporary impairments because we do not make specific investment decisions regarding the assets held in these trusts. Thus, effective in 2006, the other-than-temporary impairments are considered realized losses and will reduce the cost basis of the securities which will affect any future unrealized gain or realized gains or losses. We record unrealized gains and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the spent nuclear fuel disposal trust funds in accordance with their treatment in rates. See Note 10 for additional discussion of nuclear matters.

Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from nonowner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss).

Components of Accumulated Other Comprehensive Income (Loss)

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

Components	December 31,	
	2007	2006
	(in millions)	
Securities Available for Sale, Net of Tax	\$ 17	\$ 18
Cash Flow Hedges, Net of Tax	(26)	(6)
Pension and OPEB Funded Status, Net of Tax	(145)	(235)
Total	\$ (154)	\$ (223)

Stock-Based Compensation Plans

At December 31, 2007, we had stock options, performance units, restricted shares and restricted stock units outstanding to employees under The Amended and Restated American Electric Power System Long-Term Incentive Plan (LTIP). This plan was originally approved by shareholder vote in 2000 and the Amended and Restated version was subsequently approved in 2005.

We maintain career share accounts under the Stock Ownership Requirement Plan to facilitate executives in meeting minimum stock ownership requirements assigned to executives by the HR Committee of the Board of Directors. Career shares are derived from vested performance units granted to employees under the LTIP. Career shares are equal in value to shares of AEP common stock and do not become payable to executives until after their service ends.

We also compensate our non-employee directors, in part, with stock units under The Stock Unit Accumulation Plan for Non-Employee Directors. These stock units also do not become payable in cash to Directors until after their service ends.

In addition, we maintain a variety of tax qualified and nonqualified deferred compensation plans for employees and non-employee directors that include, among other options, an investment in or an investment return equivalent to that of AEP stock.

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.

In conjunction with the adoption of SFAS 123R, for awards with service only conditions 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. We recognize compensation expense for all share-based payment awards granted prior to January 1, 2006 using the accelerated multiple-option approach while we recognize compensation expense for all share-based payment awards with service only condition granted on or after January 1, 2006 using the straight-line single-option method. In 2007 and 2006, we granted awards with performance conditions which continue to be expensed on the accelerated multiple-option approach. As stock-based compensation expense recognized on our Consolidated Statements of Income for the years ended December 31, 2007 and 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 as required under SFAS 123 for the periods prior to 2006, we accounted for forfeitures as they occurred.

For the year ended December 31, 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. For the years ended December 31, 2007, 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 16 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 year ended December 31, 2005:

	2005
	(in millions, except per share data)
Net Income, as reported	\$ 814
Add: Stock-based compensation expense included in reported Net Income, net of related tax effects	22
Deduct: Stock-based compensation expense determined under fair value based method for all awards, net of related tax effects	(22)
Pro Forma Net Income	\$ 814
Earnings Per Share	
Basic – as Reported	\$ 2.09
Basic – Pro Forma (a)	\$ 2.09
Diluted – as Reported	\$ 2.08
Diluted – Pro Forma (a)	\$ 2.08

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

Earnings Per Share (EPS)

Basic earnings per common share is calculated by dividing net earnings available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings per common share is calculated by adjusting the weighted average outstanding common shares, assuming conversion of all potentially dilutive stock options and awards.

The following table presents our basic and diluted EPS calculations included on our Consolidated Statements of Income:

	Years Ended December 31,					
	2007		2006		2005	
	(in millions, except per share data)					
		\$/share		\$/share		\$/share
Earnings Applicable to Common Stock	<u>\$ 1,089</u>		<u>\$ 1,002</u>		<u>\$ 814</u>	
Average Number of Basic Shares Outstanding	398.8	\$ 2.73	394.2	\$ 2.54	390.0	\$ 2.09
Average Dilutive Effect of:						
Performance Share Units	0.9	0.01	1.8	0.01	1.0	0.01
Stock Options	0.3	-	0.3	-	0.3	-
Restricted Stock Units	0.1	-	0.1	-	-	-
Restricted Shares	0.1	-	0.1	-	0.1	-
Average Number of Diluted Shares Outstanding	<u>400.2</u>	<u>\$ 2.72</u>	<u>396.5</u>	<u>\$ 2.53</u>	<u>391.4</u>	<u>\$ 2.08</u>

The assumed conversion of stock options does not affect net earnings (loss) for purposes of calculating diluted earnings per share.

Options to purchase 0.1 million, 0.4 million and 0.5 million shares of common stock were outstanding at December 31, 2007, 2006 and 2005, respectively, but were not included in the computation of diluted earnings per share because the options' exercise prices were greater than the year-end market price of the common shares and, therefore, the effect would be antidilutive.

Supplementary Information

Related Party Transactions	Years Ended December 31,		
	2007	2006	2005
		(in millions)	
AEP Consolidated Purchased Energy:			
Ohio Valley Electric Corporation (43.47% Owned)	\$ 226	\$ 223	\$ 196
Sweeny Cogeneration Limited Partnership (a)	86	121	141
AEP Consolidated Other Revenues – Barging and Other Transportation Services – Ohio Valley Electric Corporation (43.47% Owned)	31	28	20
AEP Consolidated Revenues – Utility Operations:			
Power Pool Purchases – Ohio Valley Electric Corporation (43.47% Owned)	(29)	(37)	-

(a) In October 2007, we sold our 50% ownership in the Sweeny Cogeneration Limited Partnership. See “Sweeny Cogeneration Plant” section of Note 8.

Cash Flow Information	Years Ended December 31,		
	2007	2006	2005
		(in millions)	
Cash paid for:			
Interest, Net of Capitalized Amounts	\$ 734	\$ 664	\$ 637
Income Taxes, Net of Refunds	576	358	439
Noncash Investing and Financing Activities:			
Acquisitions Under Capital Leases	160	106	63
Assumption (Disposition) of Liabilities Related to Acquisitions/Divestitures, Net	8	-	(18)
Disposition of Assets Related to Electric Transmission Texas Joint Venture	(14)	-	-
Noncash Construction Expenditures Included in Accounts Payable at December 31	345	404	253
Noncash Acquisition of Nuclear Fuel in Accounts Payable at December 31	84	-	24

Transmission Investments

We participate in certain joint ventures which involve transmission projects to own and operate transmission facilities in the ERCOT and PJM service territories. These investments are 50% owned and recorded using the equity method and reported as Deferred Charges and Other on our Consolidated Balance Sheets.

Power Projects

During 2007, we sold our 50% interest in Sweeny, a domestic unregulated power plant with a capacity of 480 MW located in Texas. Our 50% interest in an international power plant totaling 600 MW located in Mexico was sold in 2006 (see “Dispositions” section of Note 8).

We account for investments in power projects that are 50% or less owned using the equity method and report them as Deferred Charges and Other on our Consolidated Balance Sheets.

Reclassifications

Certain prior period financial statement items have been reclassified to conform to current period presentation. These reclassifications had no impact on our previously reported results of operations, cash flows or changes in shareholders' equity.

2. NEW ACCOUNTING PRONOUNCEMENTS, EXTRAORDINARY ITEMS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE

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 final pronouncements that we have determined relate to our operations.

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

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

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

SFAS 157 "Fair Value Measurements" (SFAS 157)

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

In February 2008, the FASB issued FASB Staff Position (FSP) FAS 157-1 "Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13" which amends SFAS 157 to exclude SFAS 13 "Accounting for Leases" and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement under SFAS 13.

In February 2008, the FASB issued FSP FAS 157-2 "Effective Date of FASB Statement No. 157" which delays the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually).

We partially adopted SFAS 157 effective January 1, 2008. We will adopt SFAS 157 effective January 1, 2009 for items within the scope of FSP FAS 157-2. The provisions of SFAS 157 are applied prospectively, except for a) changes in fair value measurements of existing derivative financial instruments measured initially using the

transaction price under EITF 02-3, b) existing hybrid financial instruments measured initially at fair value using the transaction price and c) blockage discount factors. Although the statement is applied prospectively upon adoption, in accordance with the provisions of SFAS 157 related to EITF 02-3, we recorded an immaterial transition adjustment to beginning retained earnings. The impact of considering our own credit risk when measuring the fair value of liabilities, including derivatives, had an immaterial impact on fair value measurements upon adoption.

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

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

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

SFAS 160 “Noncontrolling Interest in Consolidated Financial Statements” (SFAS 160)

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

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

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

In March 2007, the FASB ratified EITF 06-10, a consensus on collateral assignment split-dollar life insurance arrangements in which an employee owns and controls the insurance policy. Under EITF 06-10, an employer should recognize a liability for the postretirement benefit related to a collateral assignment split-dollar life insurance arrangement in accordance with SFAS 106 “Employers’ Accounting for Postretirement Benefits Other Than Pension” or Accounting Principles Board Opinion No. 12 “Omnibus Opinion – 1967” if the employer has agreed to maintain a life insurance policy during the employee’s retirement or to provide the employee with a death benefit based on a substantive arrangement with the employee. In addition, an employer should recognize and measure an asset based on the nature and substance of the collateral assignment split-dollar life insurance arrangement. EITF 06-10 requires recognition of the effects of its application as either (a) a change in accounting principle through a cumulative effect adjustment to retained earnings or other components of equity or net assets in the statement of financial position at the beginning of the year of adoption or (b) a change in accounting principle through retrospective application to all prior periods. We adopted EITF 06-10 effective January 1, 2008 with an immaterial effect on our financial statements.

EITF Issue No. 06-11 “Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards” (EITF 06-11)

In June 2007, the FASB ratified the EITF consensus on the treatment of income tax benefits of dividends on employee share-based compensation. The issue is how a company should recognize the income tax benefit received on dividends that are paid to employees holding equity-classified nonvested shares, equity-classified nonvested

share units or equity-classified outstanding share options and charged to retained earnings under SFAS 123R, "Share-Based Payments." Under EITF 06-11, a realized income tax benefit from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for equity-classified nonvested equity shares, nonvested equity share units and outstanding equity share options should be recognized as an increase to additional paid-in capital.

We adopted EITF 06-11 effective January 1, 2008. EITF 06-11 is applied prospectively to the income tax benefits of dividends on equity-classified employee share-based payment awards that are declared in fiscal years after September 15, 2007. The adoption of this standard had an immaterial impact on our financial statements.

FIN 48 "Accounting for Uncertainty in Income Taxes" and FASB Staff Position FIN 48-1 "Definition of Settlement in FASB Interpretation No. 48" (FIN 48)

In July 2006, the FASB issued FASB Interpretation No. 48 "Accounting for Uncertainty in Income Taxes" and in May 2007, the FASB issued FASB Staff Position FIN 48-1 "Definition of *Settlement* in FASB Interpretation No. 48." 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. We adopted FIN 48 effective January 1, 2007, with an unfavorable adjustment to retained earnings of \$17 million.

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

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

We adopted FIN 39-1 effective January 1, 2008. This standard changed our method of netting certain balance sheet amounts and reduced assets and liabilities by an immaterial amount. It requires retrospective application as a change in accounting principle for all periods presented.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by the 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 revenue recognition, liabilities and equity, derivatives disclosures, emission allowances, 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.

EXTRAORDINARY ITEMS

Virginia Restructuring

In April 2007, Virginia passed legislation to reestablish regulation for retail generation and supply of electricity. As a result, we recorded an extraordinary loss of \$118 million (\$79 million, net of tax) in 2007 for the reestablishment of regulatory assets and liabilities related to our Virginia retail generation and supply operations. In 2000, we discontinued SFAS 71 regulatory accounting in our Virginia jurisdiction for retail generation and supply operations due to the passage of legislation for customer choice and deregulation. See "Virginia Restructuring" section of Note 4.

Texas Stranded Costs Recovery

Results for 2005 reflect net adjustments made by TCC to its net true-up regulatory asset for the PUCT's final order in its True-up Proceeding issued in February 2006. Based on the final order, TCC's net true-up regulatory asset was reduced by \$384 million. Of the \$384 million, \$345 million (\$225 million, net of tax) was recorded as an extraordinary item in accordance with SFAS 101 "Regulated Enterprises – Accounting for the Discontinuation of Application of FASB Statement No. 71" and is reflected in Extraordinary Loss, Net of Tax on our Consolidated Statement of Income.

CUMULATIVE EFFECT OF ACCOUNTING CHANGE

Asset Retirement Obligations

In 2005, we recorded a \$26 million (\$17 million, net of tax) cumulative effect of accounting change for ARO in accordance with FIN 47 in the Utility Operations segment. This adjustment is included in Cumulative Effect of Accounting Change, Net on our 2005 Consolidated Statement of Income.

3. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

The changes in our carrying amount of goodwill for the years ended December 31, 2007 and 2006 by operating segment are as follows:

	<u>Utility Operations</u>	<u>MEMCO Operations</u> (in millions)	<u>AEP Consolidated</u>
Balance at December 31, 2005	\$ 37	\$ 39	\$ 76
Impairment Losses	-	-	-
Balance at December 31, 2006	37	39	76
Impairment Losses	-	-	-
Balance at December 31, 2007	<u>\$ 37</u>	<u>\$ 39</u>	<u>\$ 76</u>

In the fourth quarters of 2006 and 2007, we performed our annual impairment tests. The fair values of the operations with goodwill were estimated using cash flow projections and other market value indicators. There were no goodwill impairment losses.

Other Intangible Assets

Acquired intangible assets subject to amortization were \$15.2 million at December 31, 2007 and \$19.4 million at December 31, 2006, net of accumulated amortization and are included in Deferred Charges and Other on our Consolidated Balance Sheets. The amortization life, gross carrying amount and accumulated amortization by major asset class are as follows:

		December 31,			
		2007		2006	
Amortization Life (in years)	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization	
		(in millions)			
Patent	5	\$ 0.1	\$ 0.1	\$ 0.1	\$ 0.1
Easements	10	2.2	1.4	2.2	1.1
Purchased Technology	10	10.9	6.4	10.9	5.4
Advanced Royalties	10	29.4	19.5	29.4	16.6
Total		<u>\$ 42.6</u>	<u>\$ 27.4</u>	<u>\$ 42.6</u>	<u>\$ 23.2</u>

Amortization of intangible assets was \$4 million, \$5 million and \$4 million for 2007, 2006 and 2005, respectively. Our estimated total amortization is \$3 million for 2008, \$2 million per year for 2009 through 2012 and \$1 million per year for 2013 through 2016, when all assets will be fully amortized with no residual value.

The Advanced Royalties asset class relates to the lignite mine of Dolet Hills Lignite Company, a wholly-owned subsidiary of SWEPCo. In 2008, we expect to receive an order from the LPSC that will extend the useful life of the mine for an additional six years, which is factored in the estimates noted above.

Other than goodwill, we have no intangible assets that are not subject to amortization.

4. RATE MATTERS

Our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. This note is a discussion of rate matters and industry restructuring related proceedings that could have a material effect on the results of operations and cash flows.

Ohio Rate Matters

Ohio Restructuring and Rate Stabilization Plans

CSPCo and OPCo have three automatic annual generation rate increases of 3% and 7%, respectively, the last of which became effective January 1, 2008. The RSP also allows additional annual generation rate increases of up to an average of 4% per year to recover new governmentally-mandated costs.

In March 2007, CSPCo also filed an application under the average 4% generation rate provision of its RSP to adjust the Power Acquisition Rider (PAR) related to CSPCo's acquisition of Monongahela Power Company's certified territory in Ohio. The PAR was increased to recover the cost of a new purchase power market contract to serve the load for that service territory. The PUCO approved this requested increase, which increased CSPCo's revenues by \$22 million in 2007, and is expected to increase 2008 revenues by \$38 million.

In May 2007, the PUCO approved a settlement agreement resolving the Ohio Supreme Court's remand of the PUCO's RSP order. The settling parties agreed to have CSPCo and OPCo take bids for Renewable Energy Certificates (RECs). Under the approved settlement, CSPCo and OPCo will give customers the option to pay a generation rate premium that would encourage the development of renewable energy sources by reimbursing CSPCo and OPCo for the cost of the RECs.

In May 2007, CSPCo and OPCo implemented proposed increases from the average 4% proceeding of \$24 million and \$8 million, respectively, subject to refund. In October 2007, the PUCO issued an order that granted CSPCo and OPCo an annual increase of \$19 million and \$4 million, respectively. In September 2007, CSPCo and OPCo recorded a provision to refund the over-collected revenues.

On January 30, 2008, the PUCO approved a settlement agreement among CSPCo, OPCo and other parties related to an additional average 4% generation rate increase and TCRR adjustments for additional governmentally-mandated costs including increased environmental costs and PJM's revision of its pricing methodology for transmission line losses. Under the settlement, the PUCO approved recovery through the TCRR increased PJM costs associated with transmission line losses of \$39 million each for CSPCo and OPCo. As a result, CSPCo and OPCo established regulatory assets in the first quarter of 2008 of \$12 million and \$14 million, respectively, related to increased PJM costs from June 2007 to December 2007. See the "PJM Marginal-Loss Pricing" in the "FERC Rate Matters" section of this note. The PUCO also approved a credit applied to the TCRR of \$10 million for OPCo and \$8 million for CSPCo for PJM net congestion costs. To the extent that collections for the TCRR items are over/under actual net costs, we will adjust billings to reflect actual costs including carrying costs. Under the terms of the settlement, although the increased PJM costs associated with transmission line losses will be recovered through the TCRR, these recoveries will still be applied to reduce the annual average 4% generation rate increase limitation. In addition, the PUCO approved recoveries of environmental costs and related carrying costs of \$29 million for CSPCo and \$5 million for OPCo. These rate adjustments have been implemented effective February 2008.

As permitted by the current Ohio restructuring legislation, CSPCo and OPCo can implement market-based rates effective January 2009, following the expiration of their RSPs on December 31, 2008. The RSP plans include generation rates which are between cost and higher market rates. In August 2007, legislation was introduced that would limit CSPCo's and OPCo's ability to charge market-based rates for generation at the expiration of their RSPs. The Ohio Senate passed legislation and it is being considered by the Ohio House of Representatives. Management continues to analyze the proposed legislation and is working with various stakeholders to achieve a principled, fair and well-considered approach to electric supply pricing. At this time, management is unable to predict whether CSPCo and OPCo will transition to market pricing, extend their RSP rates, with or without modification, or become subject to a legislative reinstatement of some form of cost-based regulation for their generation supply business on January 1, 2009. The return to cost-based regulation could cause the generation business of CSPCo and OPCo, in whole or in part, to meet the criteria for application of SFAS 71. If CSPCo and OPCo are required to reestablish certain net regulatory liabilities applicable to their generation business, it could result in an extraordinary item and a decrease in future results of operations and financial condition.

Customer Choice Deferrals

CSPCo's and OPCo's restructuring settlement agreement, approved by the PUCO in 2000, allow CSPCo and OPCo to establish regulatory assets for customer choice implementation costs and related carrying costs in excess of \$20 million each for recovery in the next general base rate filing for the distribution business. Through December 31, 2007, CSPCo and OPCo incurred \$53 million and \$54 million, respectively, of such costs and established regulatory assets for future recovery of \$26 million each, net of equity carrying costs of \$7 million for CSPCo and \$8 million for OPCo. Management believes that these costs were prudently incurred to implement customer choice in Ohio and are probable of recovery in future distribution rates. However, failure of the PUCO to ultimately approve recovery of such costs would have an adverse effect on results of operations and cash flows.

Ohio IGCC Plant

In March 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs related to building and operating a 629 MW IGCC power plant using clean-coal technology. The application proposed three phases of cost recovery associated with the IGCC plant: Phase 1, recovery of \$24 million in pre-construction costs; Phase 2, concurrent 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 cost to construct the plant.

In June 2006, the PUCO issued an order approving a tariff to recover Phase 1 pre-construction costs over a period of no more than twelve months effective July 1, 2006. During that period CSPCo and OPCo each collected \$12 million in preconstruction costs. The recoveries were applied against the average 4% limit on additional generation rate increases CSPCo and OPCo could request under their RSPs.

If CSPCo and OPCo have not commenced a continuous course of construction of the proposed IGCC plant within five years of the June 2006 PUCO order, all Phase 1 costs associated with items that may be utilized in projects at other sites, must be refunded to Ohio ratepayers with interest. The PUCO deferred ruling on cost recovery for Phases 2 and 3 pending further hearings.

In August 2006, intervenors filed four separate appeals of the PUCO's order in the IGCC proceeding. The Ohio Supreme Court heard oral arguments for these appeals in October 2007. Management believes that the PUCO's authorization to collect Phase 1 preconstruction costs is lawful. Management, however, cannot predict the outcome of these appeals. If the PUCO's order is found to be unlawful, CSPCo and OPCo could be required to refund the \$12 million each has collected in Phase 1 preconstruction costs which would have an adverse effect on future results of operations and cash flows.

Pending the outcome of the Supreme Court litigation, CSPCo and OPCo announced they would delay the start of construction of the IGCC plant. Recent estimates of the cost to build the proposed IGCC plant are approximately \$2.7 billion. If the commencement of construction is delayed beyond 2011, CSPCo and OPCo may need to request from the PUCO an extension of the deadline to commence construction of the IGCC plant.

Transmission Rate Filing

In accordance with the RSPs, in December 2005, the PUCO approved the recovery of certain RTO transmission costs through separate transmission cost recovery riders ("TCRR") for the Ohio companies. The TCRRs are subject to an annual true-up process. In October 2007, CSPCo and OPCo proposed increases in annual TCRR revenue of \$55 million and \$59 million, respectively, due to the under-recovery of costs in 2007, carrying costs on that under-recovery and escalating 2008 transmission costs. The PUCO approved this request and the new TCRR became effective at the start of the January 2008 billing cycle. See "Ohio Restructuring and Rate Stabilization Plans" above for a discussion of the settlement agreement which resulted in an additional adjustment to the TCRR.

Ormet

Effective January 1, 2007, CSPCo and OPCo began to serve Ormet, a major industrial customer with a 520 MW load, in accordance with a settlement agreement approved by the PUCO. The settlement agreement allows for the recovery in 2007 and 2008 of the difference between the \$43 per MWH Ormet pays for power and a PUCO-approved market price, if higher. The PUCO approved a \$47.69 per MWH market price for 2007. The recovery generally will be accomplished by the amortization of a \$57 million (\$15 million for CSPCo and \$42 million for OPCo) excess deferred tax regulatory liability resulting from an Ohio franchise tax phase-out recorded in 2005.

CSPCo and OPCo each amortized \$7 million of this regulatory liability to income through December 31, 2007. In December 2007, CSPCo and OPCo submitted a market price of \$53.03 per MWH for 2008. If the PUCO approves a market price for 2008 below the 2007 price, it could have an adverse effect on future results of operations and cash flows. If CSPCo and OPCo serve the Ormet load after 2008 without any special provisions, they could experience incremental costs to acquire additional capacity to meet their reserve requirements and/or forgo off-system sales margins.

Texas Rate Matters

TEXAS RESTRUCTURING

TCC Texas Restructuring Appeals

Pursuant to PUCT orders, TCC securitized its net recoverable stranded generation costs of \$2.5 billion and is recovering such costs over a period ending in 2020. TCC is also refunding its net other true-up items of \$375 million through 2008 via a CTC credit rate rider. TCC appealed the PUCT stranded costs true-up and related orders seeking relief in both state and federal court on the grounds that certain aspects of the orders are contrary to the Texas Restructuring Legislation, PUCT rulemakings and federal law and fail to fully compensate TCC for its net stranded cost and other true-up items. The significant items appealed by TCC are:

- The PUCT ruling that TCC did not comply with the Texas Restructuring Legislation and PUCT rules regarding the required auction of 15% of its Texas jurisdictional installed capacity, which led to a significant disallowance of capacity auction true-up revenues.
- The PUCT ruling that TCC acted in a manner that was commercially unreasonable, because TCC failed to determine a minimum price at which it would reject bids for the sale of its nuclear generating plant and TCC bundled out-of-the-money gas units with the sale of its coal unit, which led to the disallowance of a significant portion of TCC's net stranded generation plant costs.
- The two federal matters regarding the allocation of off-system sales related to fuel recoveries and a potential tax normalization violation.

Municipal customers and other intervenors also appealed the PUCT true-up and related orders seeking to further reduce TCC's true-up recoveries. In March 2007, the Texas District Court judge hearing the appeal of the true-up order affirmed the PUCT's April 2006 final true-up order for TCC with two significant exceptions. The judge determined that the PUCT erred by applying an invalid rule to determine the carrying cost rate for the true-up of stranded costs. However, the District Court did not rule that the carrying cost rate was inappropriate. If the PUCT reevaluates the carrying cost rate on remand and reduces the rate, it could result in a material adverse change to TCC's recoverable carrying costs, results of operations, cash flows and financial condition.

The District Court judge also determined that the PUCT improperly reduced TCC's net stranded plant costs for commercial unreasonableness. If upheld on appeal, this ruling could have a materially favorable effect on TCC's results of operations and cash flows.

TCC, the PUCT and intervenors appealed the District Court decision to the Texas Court of Appeals. Management cannot predict the outcome of these court proceedings. If TCC ultimately succeeds in its appeals, it could have a favorable effect on future results of operations, cash flows and financial condition. If municipal customers and other intervenors succeed in their appeals, or if TCC has a tax normalization violation, it could have a substantial adverse effect on future results of operations, cash flows and financial condition.

TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes

Appeals remain outstanding related to the stranded costs true-up and related orders regarding whether the PUCT may require TCC to refund certain tax benefits to customers. The PUCT agreed to allow TCC to defer a \$103 million refund to customers (\$61 million in present value of the tax benefits associated with TCC's generation assets plus \$42 million of related carrying costs) pending resolution of whether the PUCT's proposed refund is an IRS normalization violation.

If it is ultimately determined that a refund to customers through the true-up process of these tax benefits is not a normalization violation, then TCC will be required to refund the \$103 million, plus additional carrying costs adversely affecting future cash flows. However, if it is ultimately determined that a normalization violation would result from the original PUCT proposal, TCC expects that the PUCT will allow TCC to retain these amounts which will have a favorable effect on future results of operations and cash flows as the Accumulated Deferred Investment Tax Credits (ADITC) and Excess Deferred Federal Income Taxes (EDFIT) are taken to income due to the sale of the generating plants.

If a normalization violation occurs, it could result in TCC's repayment to the IRS of ADITC on all property, including transmission and distribution property, which approximates \$104 million as of December 31, 2007, and a loss of TCC's right to claim accelerated tax depreciation in future tax returns. Tax counsel advised management that a normalization violation should not occur until all remedies under law have been exhausted and the tax benefits are actually returned to ratepayers under a nonappealable order. The PUCT requested that the Texas Court of Appeals remand the tax normalization issue for the PUCT to consider additional evidence. Management intends to continue its efforts to work with the PUCT to avoid a normalization violation.

TCC and TNC Deferred Fuel

TCC, TNC and the PUCT have been involved in litigation in the federal courts concerning whether the PUCT has the right to order reallocation of off-system sales margins thereby reducing recoverable fuel costs. In 2005, TCC and TNC recorded provisions for refunds after the PUCT ordered such reallocation. After receipt of favorable federal court decisions and the refusal of the Supreme Court of the United States to hear a PUCT appeal, TCC and TNC reversed their provisions in the third quarter of 2007 of \$16 million and \$9 million, respectively.

The PUCT or another interested party could file a complaint at the FERC to challenge the allocation of off-system sales margins under the FERC-approved allocation agreement. In December 2007, some cities served by TNC requested the PUCT to initiate, or order TNC to initiate a proceeding at the FERC to determine if TNC misapplied its tariff. In January 2008, TNC filed a response with the PUCT recommending the cities' request be denied. Although management cannot predict if a complaint will be filed at the FERC, management believes the allocations were in accordance with the then-existing FERC-approved allocation agreement and additional off-system sales margins should not be retroactively reallocated to the AEP West companies including TCC and TNC.

TCC Excess Earnings

In 2005, a Texas appellate court issued a decision finding that a PUCT order requiring TCC to refund to the REPs excess earnings prior to and outside of the true-up process was unlawful under the Texas Restructuring Legislation. From 2002 to 2005, TCC refunded \$55 million of excess earnings, including interest, under the overturned PUCT order. On remand, the PUCT must determine how to implement the Court of Appeals decision given that the unauthorized refunds were made in lieu of reducing stranded cost recoveries in the True-up Proceeding. As a result,

TCC's stranded cost recovery, which is currently on appeal, may be affected by a PUCT remedy. In December 2007, the Texas Court of Appeals issued a decision in CenterPoint's, a nonaffiliated Texas utility, true-up proceeding determining that even though excess earnings had been previously refunded to the affiliated REP, CenterPoint still must reduce stranded cost recoveries in its true-up proceeding. In 2005, TCC reflected the obligation to refund excess earnings to customers through the true-up process and recorded a regulatory asset for the expected refund to be received from the REPs. However, certain parties have taken positions that, if adopted, could result in TCC being required to refund additional amounts of excess earnings or interest through the true-up process without receiving a refund from the REPs. If this were to occur it would have an adverse effect on future results of operations and cash flows. AEP sold its affiliate REPs in December 2002. While AEP owned the affiliate REP, TCC refunded \$11 million of excess earnings to the affiliate REP. Management cannot predict the outcome of these matters.

Texas Restructuring – SPP

In August 2006, the PUCT adopted a rule extending the delay in implementation of customer choice in the SPP area of Texas until no sooner than January 1, 2011. This extension impacts SWEPCo's Texas service territory.

OTHER TEXAS RATE MATTERS

TCC and TNC Energy Delivery Base Rate Filings

TCC and TNC each filed a base rate case seeking to increase transmission and distribution energy delivery services (wires) base rates in Texas. TCC and TNC's revised requested increase in annual base rates was \$70 million and \$22 million, respectively, based on a requested return on common equity of 10.75%.

In May 2007, the PUCT approved a settlement agreement for TNC, which resulted in an \$8 million increase in base rates, a \$6 million increase related to the impact of the expiration of the merger credits and a return on common equity of 9.96%. TNC estimates the settlement will increase annual revenues by \$14 million. TNC began billing the increased rates in June 2007.

TCC implemented the rate change in June 2007 subject to refund. In January 2008, the PUCT issued an order approving rates to collect a \$20 million base rate increase based on a return on common equity of 9.96% and an additional \$20 million increase in revenues related to the expiration of TCC's merger credits. In addition, depreciation expense was decreased by \$7 million and discretionary fee revenues were increased by \$3 million. TCC estimates the order will increase TCC's annual pretax income by \$50 million.

SWEPCo Fuel Reconciliation – Texas

In June 2006, SWEPCo filed a fuel reconciliation proceeding with the PUCT for its Texas retail operations for the three-year reconciliation period ended December 31, 2005 seeking to recover under-recoveries of \$50 million. In June 2007, an ALJ issued a proposal for decision recommending a \$17 million disallowance. Results of operations for the second quarter of 2007 were adversely affected by \$25 million to reflect the ALJ's decision, which applied to items in the reconciliation period and subsequent periods through 2007. The PUCT issued an order in August 2007 adopting the ALJ's recommendation; however, in response to a SWEPCo motion for rehearing, the PUCT clarified the rationale for crediting to fuel certain gains from sales of emissions allowances and limited the application to gains realized through June 15, 2006. As a result, in the fourth quarter of 2007 SWEPCo reversed \$7 million of its provision which related to gains from sales of emissions allowances subsequent to June 15, 2006.

Stall Unit

See "Stall Unit" section within Louisiana Rate Matters for disclosure.

Turk Plant

See "Turk Plant" section within Arkansas Rate Matters for disclosure.

Virginia Rate Matters

Virginia Restructuring

In April 2007, the Virginia legislature adopted a comprehensive law providing for the re-regulation on a cost basis of electric utilities' generation and supply rates after the December 31, 2008 expiration of capped rates. The legislation provides for, among other things, biennial rate reviews beginning in 2009; rate adjustment clauses for the recovery of the costs of (a) transmission services and new transmission investments, (b) demand side management, load management, and energy efficiency programs, (c) renewable energy programs, and (d) environmental retrofit and new generation investments. It also provided for significant return on equity enhancements for investments in new generation and, subject to Virginia SCC approval, certain environmental retrofits, and a minimum allowed return on equity which will be based on the average earned return on equities of regional vertically integrated electric utilities. In addition, effective September 1, 2007, APCo is allowed to retain a minimum of 25% of the margins from off-system sales with the remaining margins from such sales credited against fuel factor expenses with a true-up to actual. The legislation also allows APCo to continue to defer and recover incremental environmental and reliability costs incurred through December 31, 2008.

With the new re-regulation legislation, APCo's generation business again met the criteria for application of regulatory accounting principles under SFAS 71. APCo reapplied SFAS 71 in the second quarter of 2007 and recorded an extraordinary pretax reduction in our earnings and shareholder's equity of \$118 million (\$79 million, net of tax). This extraordinary net loss relates to the reestablishment of \$139 million in net generation-related customer-provided removal costs as a regulatory liability, offset by the restoration of \$21 million of deferred state income taxes as a regulatory asset. In addition, APCo established a regulatory asset of \$17 million for qualifying SFAS 158 pension costs of the generation operations that, for ratemaking purposes, are deferred for future recovery under the new re-regulation legislation. As a result, AOCI and Deferred Income Taxes increased by \$11 million and \$6 million, respectively.

Virginia Base Rate Case

In May 2006, APCo filed a request with the Virginia SCC seeking a net base rate increase of \$198 million based on a return on equity of 11.5%. Pursuant to APCo's request, the Virginia SCC issued an order placing the net requested base rate increase of \$198 million into effect on October 2, 2006, subject to refund.

In May 2007, the Virginia SCC issued a final order approving an overall annual base rate increase of \$24 million effective as of October 2006 based on a return on equity of 10.0%. The final order resulted in a \$9 million net deferral of ARO costs to be recovered over 10 years, an \$11 million annual decrease in depreciation expense retroactive to January 1, 2006 and implemented a base rate off-system sales margin credit equal to 100% of estimated off-system sales margins. APCo completed a \$127 million refund in August 2007 for the difference between the requested and approved rates. As a result of a Virginia SCC decision to limit the inclusion of incremental E&R costs through June 30, 2006 in new base rates, APCo will continue to defer for future recovery unrecovered incremental E&R costs incurred through 2008 utilizing the E&R surcharge mechanism. APCo estimates the new base rates will increase annual pretax income by \$34 million.

Virginia E&R Costs Recovery Filing

In July 2007, APCo filed a request with the Virginia SCC seeking recovery over the twelve months beginning December 1, 2007 of approximately \$60 million of unrecovered incremental E&R costs based on a return of equity of 12% and inclusive of carrying costs for the period from October 1, 2005 through September 30, 2006. In December 2007, the Virginia SCC issued a final order approving the recovery of \$49 million of deferred incremental E&R costs over a twelve month period beginning January 1, 2008 based on a 9.9% return on equity and denied APCo's request for carrying costs on the unrecovered incremental E&R costs.

APCo recovered \$26 million of incremental E&R costs in the rider that ended on November 30, 2007. As of December 31, 2007, APCo has deferred \$82 million of incremental E&R costs to be recovered through current and future E&R surcharges. APCo has not recognized \$19 million of E&R equity carrying charges, which are recognizable when recovered. APCo intends to file in 2008 for future recovery of incremental E&R costs incurred subsequent to September 30, 2006.

Virginia Fuel Clause Filing

In July 2007, APCo filed an application with the Virginia SCC to seek an annualized increase, effective September 1, 2007, of \$33 million for fuel costs and sharing of off-system sales, consistent with the minimum 25% retention of off-system sales margins provision of the new re-regulation legislation. The sharing requirement in the new law also includes a true-up of off-system sales credits provided to customers to actual off-system sales margins.

Pursuant to APCo's request, the Virginia SCC issued an order in August 2007 that implemented APCo's proposed termination of its base rate off-system sales margin rider on an interim basis, subject to refund, on September 1, 2007. The order also implemented APCo's proposed new fuel factor on an interim basis, effective September 1, 2007, which includes a credit for the sharing of 75% of off-system sales margins with customers in compliance with the new law.

In December 2007, APCo filed supplemental testimony requesting to defer for future recovery the increased transmission costs related to PJM's revision of its pricing methodology for transmission line losses to marginal-loss pricing which became effective June 1, 2007. The request did not change the requested actual fuel rate. Through December 31, 2007, APCo deferred \$14 million of such increased costs for future recovery related to the Virginia jurisdiction. See the "PJM Marginal-Loss Pricing" in the "FERC Rate Matters" section of this note.

In February 2008, the Virginia SCC issued an order that approved a reduced fuel factor effective with the February 2008 billing cycle. The adjusted factor will increase annual revenues by \$4 million. The order permanently terminated the off-system sales margin rider and approved the 75%-25% sharing of off-system sales margins between customers and APCo effective September 1, 2007. The order also allows APCo to include in its monthly under/over recovery deferrals its Virginia jurisdictional share of PJM transmission line loss allocated to it effective back to June 1, 2007. The order authorized the Virginia SCC staff and other parties to make specific recommendations to the Virginia SCC in APCo's next fuel factor proceeding in the fourth quarter of 2008 to ensure accurate assignment of the prudently incurred PJM transmission line loss costs to APCo's Virginia jurisdictional operations. APCo believes the incurred PJM transmission line loss costs are prudently incurred and are being properly assigned to APCo's Virginia jurisdictional operations. However, if the amount of such costs included in APCo's Virginia fuel under/over recovery deferrals is revised by the Virginia SCC in APCo's next fuel factor proceeding, it could, if applied retroactively, result in a change to the recoverable deferred fuel balance which would effect future results of operations and cash flows.

APCo's Virginia SCC Filing for the West Virginia IGCC Plant

In July 2007, APCo filed a request with the Virginia SCC for a rate adjustment clause to recover initial costs associated with a proposed 629 MW IGCC plant to be constructed in Mason County, West Virginia adjacent to APCo's existing Mountaineer Generating Station for an estimated cost of \$2.2 billion. The filing requests recovery of an estimated \$45 million over twelve months beginning January 1, 2009 including a return on projected construction work in progress and development, design and planning preconstruction costs incurred from July 1, 2007 through December 31, 2009. APCo is requesting authorization to defer a return on deferred preconstruction costs incurred beginning July 1, 2007 until such costs are recovered. Through December 31, 2007, APCo deferred for future recovery in Virginia preconstruction IGCC costs totaling \$6 million. The rate adjustment clause provisions of the new re-regulation legislation provide for full recovery of all costs of the proposed plant including recovery of an enhanced return on equity. The Virginia SCC held a hearing in February 2008 and an order is due in April 2008. If the plant is not built and these costs are not recoverable, it would have an adverse effect on future results of operations and cash flows.

West Virginia Rate Matters

APCo and WPCo Expanded Net Energy Cost (ENEC) Filing

In April 2007, the WVPSC issued an order establishing an investigation and hearing concerning APCo's and WPCo's 2007 ENEC compliance filing. The ENEC is an expanded form of fuel clause mechanism, which includes all energy-related costs including fuel, purchased power expenses, off-system sales credits and other

energy/transmission items. APCo and WPCo filed for an increase of approximately \$101 million including a \$72 million increase in the ENEC itself and a \$29 million increase in a related construction cost surcharges to become effective July 1, 2007. In June 2007, the WVPSC approved a settlement agreement, which provided for an increase in annual non-base revenues of approximately \$86 million effective July 1, 2007. This annual revenue increase includes a \$55 million ENEC increase and a \$29 million construction cost surcharge increase.

The ENEC portion of the increase is subject to a true-up to actual and should have no earnings effect due to the deferral of any over/under-recovery of actual ENEC costs.

APCo's West Virginia IGCC Plant Filing

In January 2006, APCo filed a petition with the WVPSC requesting its approval of a Certificate of Public Convenience and Necessity (CCN) to construct a 629 MW IGCC plant adjacent to APCo's existing Mountaineer Generating Station in Mason County, WV.

In June 2007, APCo filed testimony with the WVPSC supporting the requests for a CCN and for pre-approval of a surcharge rate mechanism to provide for the timely recovery of both pre-construction costs and the ongoing finance costs of the project during the construction period as well as the capital costs, operating costs and a return on equity once the facility is placed into commercial operation. The WVPSC held hearings on the requests in December 2007. If APCo receives all necessary approvals, the plant could be completed as early as mid-2012. At the time of the filing, the cost of the plant was estimated at \$2.2 billion. The statutory deadline for the WVPSC to act on APCo's request is March 2008. Through December 31, 2007, APCo deferred for future recovery in West Virginia preconstruction IGCC costs totaling \$6 million. If the plant is not built and these costs are not recoverable, it would have an adverse effect on future results of operations and cash flows.

Indiana Rate Matters

Indiana Depreciation Study Filing

In February 2007, I&M filed a request with the IURC for approval of revised book depreciation rates effective January 1, 2007. I&M recommended a decrease in pretax annual depreciation expense on an Indiana jurisdictional basis of approximately \$69 million 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 was not a request for a change in customers' electric service rates. The filing included a settlement agreement that provided for direct benefits to I&M's customers if new lower book depreciation rates were approved by the IURC. The direct benefits included a \$5 million credit to fuel costs and an approximate \$8 million smart metering pilot program. In addition, if the agreement were approved, I&M would initiate a general rate proceeding on or before July 1, 2007.

In June 2007, the IURC approved the settlement agreement, but modified the effective date of the new book depreciation rates to the date I&M filed a general rate petition. I&M filed its rate petition in June 2007 and reduced its book depreciation rates as agreed in the settlement agreement resulting in an increase of \$37 million in pretax earnings through December 31, 2007. The \$37 million increase was partially offset by a \$5 million regulatory liability, recorded in June 2007, to provide for the agreed-upon fuel credit. I&M's approved book depreciation rates are subject to further review in the general rate case.

Indiana Rate Filing

In January 2008, I&M filed for an increase in its Indiana base rates of \$82 million including a return on equity of 11.5%. The base rate increase includes a previously approved \$69 million reduction in depreciation. The filing requests trackers for certain variable components of the cost of service including PJM RTO costs, reliability enhancement costs, demand side management/energy efficiency costs, off-system sales margins and net environmental compliance costs. The trackers would increase annual revenues by \$46 million. I&M proposes to share 50% of an estimated \$96 million of off-system sales margins with ratepayers with a guaranteed minimum of \$20 million. A decision is expected from the IURC in early 2009.

Michigan Rate Matters

Michigan Restructuring

Customer choice commenced for I&M's Michigan customers on January 1, 2002. Effective on that date, the rates on I&M's Michigan customers' bills for retail electric service were unbundled to allow customers the opportunity to evaluate the cost of generation service for comparison with other offers. I&M's total base rates in Michigan remain unchanged and reflect cost of service. As of December 31, 2007, none of I&M's customers elected to change suppliers and no alternative electric suppliers are registered to compete in I&M's Michigan service territory. As a result, management concluded that as of December 31, 2007, the requirements to apply SFAS 71 continue to be met since I&M's rates for generation in Michigan continue to be cost-based regulated.

Michigan Depreciation Study Filing

In December 2006, I&M filed a depreciation study in Michigan seeking to reduce its book depreciation rates. In September 2007, the MPSC approved a settlement agreement authorizing I&M to implement new book depreciation rates. I&M agreed to decrease pretax annual book depreciation expense, on a Michigan jurisdictional basis, by approximately \$10 million a year starting on October 1, 2007. This petition was not a request for a change in Michigan retail customers' electric service rates. Presently, I&M has no plan to revise base rates in Michigan.

Kentucky Rate Matters

Validity of Nonstatutory Surcharges

In August 2007, the Franklin Circuit Court concluded the KPSC did not have the authority to order a surcharge for a gas company subsidiary of Duke Energy absent a full cost of service rate proceeding due to the lack of statutory authority. The Kentucky Attorney General (AG) notified the KPSC that the Franklin County Circuit Court judge's order in the Duke Energy case can be interpreted to include other existing surcharges, rates or fees established outside of the context of a general rate case proceeding and not specifically authorized by statute, including fuel clauses. The KPSC and Duke Energy appealed the Franklin County Circuit Court decision.

Although this order is not directly applicable to KPCo, it is possible that the AG or another intervenor could challenge KPCo's existing surcharges, which are also not specifically authorized by statute. These include KPCo's fuel clause surcharge, annual Rockport Plant capacity surcharge, merger surcredit and off-system sales credit rider. These surcharges are currently producing net annual revenues of approximately \$10 million. The KPSC has asked interested parties to brief the issue in KPCo's outstanding fuel cost proceeding. The AG has stated that the KPCo fuel clause should be invalidated because the KPSC lacked the authority to implement a fuel clause for KPCo without a full rate case review. The KPSC has issued an order stating that it has the authority to provide for surcharges and surcredits until the Court of Appeals rules. The appeals process could take up to two years to complete. The AG agreed to stay its challenge during that time. KPCo's exposure is indeterminable at this time since it is not known whether a final adverse appeal could result in a refund of prior amounts collected, which could have an adverse effect on future results of operations and cash flows.

Oklahoma Rate Matters

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

In 2002, PSO under-recovered \$42 million of purchased power costs through its fuel clause resulting from a reallocation among AEP West companies of purchased power costs for periods prior to January 1, 2002. In 2003, the OCC staff filed testimony recommending PSO recover \$42 million of the reallocated purchased power costs over three years. Intervenor's objected to allowing recovery claiming that during that same period AEP had inappropriately under allocated off-system sales credits to PSO by \$37 million under a FERC-approved allocation agreement.

In 2004, an ALJ found that the OCC lacked authority to examine whether AEP deviated from the FERC-approved allocation methodology for off-system sales margins and held that any such complaints should be addressed at the FERC. In August 2007, the OCC issued an order adopting the ALJ's recommendation that the allocation of system

sales/trading margins is a FERC jurisdictional issue. In October 2007, the OCC orally directed the OCC staff to explore filing a complaint at FERC alleging the allocation of off-system sales margins to PSO is improper, which could result in an adverse effect on future results of operations and cash flows for AEP and the AEP East companies. To date, no claim has been asserted at the FERC.

In February 2006, the OCC enacted a rule, requiring the OCC to conduct prudence reviews on PSO's generation and fuel procurement processes, practices and costs on a periodic basis. PSO filed its testimony in June 2007 covering the year 2005. The OCC Staff and intervenors filed testimony in September 2007, and hearings occurred in November 2007. The major issue raised was the alleged under allocation of off-system sales credits under the FERC-approved allocation agreements which was not jurisdictional to the OCC as previously ordered. In addition, PSO filed testimony in November 2007 covering the year 2006. Decisions for both the 2005 and 2006 prudence proceedings are expected in 2008.

In May 2007, PSO submitted a filing to the OCC to adjust its fuel/purchase power rates. In the filing, PSO netted the \$42 million of under-recovered pre-2002 reallocated purchased power costs against a \$48 million over-recovered fuel balance as of April 30, 2007. PSO began refunding the \$6 million net over-recovered fuel/purchased power cost deferral balance beginning June 2007 effectively recovering the \$42 million by May 2008. In October 2007, the OCC denied an Oklahoma Industrial Energy Consumers request for PSO to refund the \$42 million being recovered.

Management cannot predict the outcome of the pending fuel and purchased power cost recovery filings and prudence reviews. However, PSO believes its fuel and purchased power procurement practices and costs are prudent and properly incurred and that it allocated off-system sales credits consistent with governing FERC-approved agreements.

Oklahoma Rate Filing

In November 2006, PSO filed a request to increase base rates with a return on equity of 11.75%. In a subsequent revised filing, PSO requested a \$48 million increase in base rates. In October 2007, the OCC issued a final order providing for a \$10 million annual increase in base rates with a return on equity of 10%. PSO implemented \$9 million of the increase in rates in July 2007 and implemented the additional \$1 million increase in rates in October 2007. The final order also provided for an estimated \$10 million reduction in PSO's annual depreciation expense. PSO estimates this base rate final order should increase PSO's ongoing annual revenues by approximately \$10 million and have a favorable effect on pretax earnings of \$20 million.

Lawton and Peaking Generation Settlement Agreement

In November 2003, Lawton Cogeneration, L.L.C. (Lawton) sought approval for a Power Supply Agreement (the Agreement) with PSO and associated avoided cost payments. The OCC approved the Agreement which was contested by PSO.

In April 2007, the OCC approved a settlement agreement among all parties resolving all issues. The settlement agreement approved a purchase fee of \$35 million to be paid by PSO to Lawton and required Lawton to provide all rights to the Lawton Cogeneration Facility including permits, options and engineering studies to PSO. PSO paid the \$35 million purchase fee in June 2007, abandoned the relatively high cost Lawton Cogeneration Facility and recorded the purchase fee as a regulatory asset. PSO began recovering the \$35 million regulatory asset through a rider over a three-year period with a carrying charge of 8.25% which began in September 2007. In addition, PSO will recover through a rider, subject to a \$135 million cost cap, all of the traditional costs associated with plant in service of its new peaking units to be located at the Southwestern Station and Riverside Station at the time these units are placed in service, currently expected to be 2008. PSO expects these units will have a substantially lower plant-in-service cost than the proposed Lawton Cogeneration Facility purchase power cost. These costs will be recovered through the rider until cost recovery occurs through base rates in a subsequent proceeding. Under the settlement, PSO agreed to file a rate case within 18 months of the beginning of recovery of the costs of the peaking units. PSO may request approval from the OCC for recovery of unexpected costs exceeding the cost cap if special circumstances occur.

Red Rock Generating Facility

In July 2006, PSO announced an agreement with Oklahoma Gas and Electric Company (OG&E) to build a 950 MW pulverized coal ultra-supercritical generating unit. PSO would own 50% of the new unit. Under the agreement OG&E would manage construction of the plant. OG&E and PSO requested preapproval to construct the Red Rock Generating Facility and to implement a recovery rider.

In October 2007, the OCC issued a final order approving PSO's need for 450 MWs of additional capacity by the year 2012, but denied PSO and OG&E's applications for construction preapproval. The OCC stated that PSO failed to fully study other alternatives. Since PSO and OG&E could not obtain preapproval to build the Red Rock Generating Facility, PSO and OG&E cancelled the third party construction contract and their joint venture development contract. PSO believes the Red Rock preconstruction costs, associated contract cancellation fees and applicable carrying costs are probable of recovery and established a regulatory asset for future recovery. In December 2007, PSO made a filing requesting recovery of the \$21 million regulatory asset that included associated carrying costs to date, and requested to recover future carrying costs at the weighted average cost of capital ordered in PSO's last rate case. In the filing, PSO proposed to amortize the asset commensurate with gains from the sale of excess SO₂ allowances until recovered. If a settlement agreement signed in February 2008 is approved, see the "Oklahoma 2007 Ice Storms" below, PSO will have to amend its Red Rock filing since the gains from the sale of excess SO₂ allowances originally expected to offset Red Rock costs are instead expected to be fully used to offset ice storm costs in accordance with the settlement. PSO continues to believe that the prudently incurred Red Rock preconstruction and cancellation costs will be recovered. If recovery becomes no longer probable or is denied, future results of operations and cash flows would be adversely affected by the reversal of the regulatory asset. As a result of the OCC's decision, PSO will restudy various alternative options to meet its capacity and energy needs.

Oklahoma 2007 Ice Storms

In October 2007, PSO filed with the OCC requesting recovery of \$13 million of operation and maintenance expenses related to service restoration efforts after a January 2007 ice storm. PSO proposed in its application to establish a regulatory asset of \$13 million and to amortize this asset coincident with gains from the sale of excess SO₂ allowances until such gains provide for the full recovery of the ice storm regulatory asset. In December 2007, PSO expensed approximately \$70 million of additional storm restoration costs related to a December 2007 ice storm.

In February 2008, PSO entered into a settlement with certain parties covering both ice storms and filed the settlement agreement with the OCC for approval. The settlement agreement provides for PSO to record a regulatory asset for actual ice storm operation and maintenance expenses, estimated to be \$83 million, less existing deferred gains from past sales of SO₂ emission allowances of \$11 million. The net regulatory asset will earn a return of 10.92% on the unrecovered balance. Under the settlement agreement, PSO will apply proceeds from future sales of excess SO₂ emission allowances of an estimated \$26 million to recover part of the ice storm regulatory asset. PSO will recover the remaining amount of the regulatory asset plus a return of 10.92% from customers over a period of five years beginning in the fourth quarter of 2008.

Louisiana Rate Matters

Louisiana Compliance Filing

In connection with compliance filings of SWEPCo that were previously ordered to be filed with the LPSC, SWEPCo and LPSC staff signed a settlement agreement in February 2008 that prospectively resolves all issues. SWEPCo agreed to a formula rate plan (FRP) with a three-year term. Beginning August 2008, rates shall be established to allow SWEPCo to earn an adjusted return on common equity of 10.565%. The adjustments are traditional Louisiana rate filing adjustments. At this time, SWEPCo cannot estimate the rate change expected in August 2008.

If, in years two or three of the FRP, the adjusted earned return is within the range of 10.015% to 11.115%, no adjustment to rates is necessary. However, if the adjusted earned return is outside of the above-specified range, an FRP rider will be established to increase or decrease rates prospectively. If the adjusted earned return is less than

10.015%, SWEPCo will prospectively increase rates to collect 60% of the difference between 10.565% and the adjusted earned return. Alternatively, if the adjusted earned return is more than 11.115%, SWEPCo will prospectively decrease rates by 60% of the difference between the adjusted earned return and 10.565%. SWEPCo will not record over/under recoveries for refund or future recovery under this FRP.

The settlement provides for a separate credit rider prospectively decreasing Louisiana retail base rates by \$5 million over the entire three year term of the FRP, which shall not affect the adjusted earned return. This separate credit rider will cease effective August 2011.

In addition, the settlement provides for an expected reduction in depreciation rates effective October 2007. In lieu of an actual reduction in rates, SWEPCo will defer as a regulatory liability the effects of the expected depreciation reduction through July 2008. SWEPCo will amortize the regulatory liability over the three year term of the FRP as a reduction to the cost of service used to determine the adjusted earned return.

SWEPCo and the LPSC staff have submitted the settlement to an ALJ and expect the LPSC to rule on the settlement in second quarter of 2008.

Stall Unit

In May 2006, SWEPCo announced plans to build a new intermediate load 480 MW natural gas-fired combustion turbine combined cycle generating unit (the Stall Unit) at its existing Arsenal Hill Plant location in Shreveport, Louisiana. SWEPCo submitted the appropriate filings with the PUCT, the APSC, the LPSC and the Louisiana Department of Environmental Quality to seek approvals to construct the unit. The Stall Unit is estimated to cost \$378 million, excluding AFUDC, and is expected to be in service in mid-2010. As of December 2007, SWEPCo capitalized preconstruction costs of approximately \$45 million and has contractual commitments of an additional \$245 million.

In March 2007, the PUCT approved SWEPCo's need for the facility. In February 2008, the LPSC staff submitted testimony in support of the Stall Unit and one intervenor submitted testimony opposing the Stall Unit due to the increase in cost. The LPSC has hearings scheduled for April 2008 and the APSC has not established a procedural schedule at this time. If SWEPCo is not authorized to build the Stall Unit, SWEPCo would seek recovery of the capitalized preconstruction costs including any cancellation fees. If SWEPCo cannot recover its capitalized costs, including any cancellation fees, it could have an adverse effect on future results of operations and cash flows.

Turk Plant

See "Turk Plant" section within Arkansas Rate Matters for disclosure.

Arkansas Rate Matters

Turk Plant

In August 2006, SWEPCo announced plans to build a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas named the John W. Turk, Jr. (Turk) Plant. SWEPCo submitted filings with the APSC, the PUCT and the LPSC seeking approval of the plant. SWEPCo will own 73% of the Turk Plant and will operate the facility. During 2007, SWEPCo signed joint ownership agreements with Oklahoma Municipal Power Authority (OMPA), Arkansas Electric Cooperative Corporation (AECC) and East Texas Electric Cooperative (ETEC) for the remaining 27% of the Turk facility. The Turk Plant is estimated to cost \$1.3 billion with SWEPCo's portion estimated to cost \$950 million, excluding AFUDC. If approved on a timely basis, the plant is expected to be in-service in 2012. As of December 2007, SWEPCo capitalized approximately \$272 million of expenditures and has significant contractual commitments for an additional \$943 million.

In November 2007, the APSC granted approval to build the plant. Certain landowners filed a notice of appeal to the Arkansas State Court of Appeals. SWEPCo is still awaiting approvals from the Arkansas Department of Environmental Quality and the U.S. Army Corps of Engineers. Both approvals are anticipated to be received in the second or third quarter of 2008. The PUCT held hearings in October 2007. In January 2008, a Texas ALJ issued a report, which concluded that SWEPCo failed to prove there was a need for the plant. The Texas ALJ recommended

that SWEPCo's application be denied. The LPSC held hearings in September 2007 in which the LPSC staff expressed support for the project. In February 2008, a Louisiana ALJ issued a report which concluded that SWEPCo has demonstrated a need for additional capacity, and that a diversified fuel mix is an important attribute that should be taken into account in an overall strategic plan. The Louisiana ALJ recommended that SWEPCo's application be approved. SWEPCo expects decisions from the PUCT and the LPSC in the first half of 2008. If SWEPCo is not authorized to build the Turk plant, SWEPCo could incur significant cancellation fees to terminate its commitments and would be responsible to reimburse OMPA, AECC and ETEC for their share of costs. If that occurred, SWEPCo would seek recovery of its capitalized costs including any cancellation fees and joint owner reimbursements. If SWEPCo cannot recover its capitalized costs, it could have an adverse effect on future results of operations, cash flows and possibly financial condition.

Stall Unit

See "Stall Unit" section within Louisiana Rate Matters for disclosure.

FERC Rate Matters

Transmission Rate Proceedings at the FERC

SECA Revenue Subject to Refund

Effective December 1, 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 31, 2006. Intervenors objected to the temporary SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than they collected. If a refund is ordered, the AEP East companies would also receive refunds related to the SECA rates they paid to third parties. The AEP East companies recognized gross SECA revenues of \$220 million from December 2004 through March 2006 when the SECA rates terminated leaving AEP and ultimately its internal load customers to make up the short fall in revenues. Approximately \$10 million of SECA revenues billed by PJM and recognized by the AEP East companies were not collected. The AEP East companies filed a motion with the FERC to force payment of these uncollected SECA billings.

In August 2006, a FERC ALJ issued an initial decision, finding that the rate design for the recovery of SECA charges was flawed and that a large portion of the "lost revenues" reflected in the SECA rates was not recoverable. The ALJ found that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made. The ALJ also found that the unpaid SECA rates must be paid in the recommended reduced amount. As a result, SECA ratepayers are engaged with AEP in settlement discussions. Management has been advised by external FERC counsel that it is probable that the FERC will reverse the ALJ's decision as it is contrary to two prior FERC decisions and lacks merit.

In 2006, the AEP East companies provided reserves of \$37 million for net refunds for current and future SECA settlements. After reviewing existing settlements, the AEP East companies increased their reserves by an additional \$5 million in December 2007. The AEP East companies have reached settlements related to approximately \$69 million of the \$220 million of SECA revenues for a net refund of \$3 million. The AEP East companies are also in the process of completing two settlements-in-principle on an additional \$36 million of SECA revenues and expect to make net refunds of \$4 million when those settlements are approved. Thus, completed and in-process settlements cover \$105 million of SECA revenues and cover about \$7 million of the reserve for refund, leaving approximately \$115 million of contested SECA revenues and \$35 million of refund reserves. However, if the ALJ's initial decision was upheld in its entirety, it could result in a disallowance of approximately \$90 million of the AEP East companies' remaining \$115 million of unsettled gross SECA revenues. Based on advice of external FERC counsel, recent settlement experience and the expectation that most of the unsettled SECA revenues will be settled, management believes that the remaining reserve of \$35 million is adequate to cover all remaining settlements and any uncollectible amounts.

In September 2006, AEP filed briefs jointly with other affected companies noting exceptions to the ALJ's initial decision and asking the FERC to reverse the decision in large part. Management believes that the FERC should reject the ALJ's initial decision because it contradicts prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ's findings on key issues are largely without merit. As directed by the FERC, management is working to settle the remaining \$115 million of unsettled revenues within the remaining reserve balance. Although management believes it has meritorious arguments and can settle with the remaining customers within the amount provided, management cannot predict the ultimate outcome of ongoing settlement talks and, if necessary, any future FERC proceedings or court appeals. If the FERC adopts the ALJ's decision and/or AEP cannot settle a significant portion of the remaining unsettled claims within the amount provided, it will have an adverse effect on future results of operations and cash flows.

The FERC PJM Regional Transmission Rate Proceeding

With the elimination of T&O rates and the expiration of SECA rates and after considerable administrative litigation at the FERC in which AEP sought to mitigate the effect of T&O rate elimination, the FERC failed to implement a regional rate in PJM. As a result, the AEP East companies' retail customers incur the bulk of the cost of the existing AEP east transmission zone facilities. However, the FERC ruled that the cost of any new 500 kV and higher voltage transmission facilities built in PJM will be shared by all customers in the region. It is expected that most of the new 500 kV and higher voltage transmission facilities will be built in other zones of PJM, not AEP's zone. The AEP East companies will need to obtain regulatory approvals for recovery of any costs of new facilities that are assigned to them. AEP had requested rehearing of this order which the FERC denied. Management expects to file an appeal. Management cannot estimate at this time what effect, if any, this order will have on the AEP East companies' future construction of new transmission facilities, results of operations and cash flows.

The AEP East companies increased their retail rates in Ohio, Virginia, West Virginia and Kentucky to recover lost T&O and SECA revenues. The AEP East companies are presently recovering from retail customers, approximately 85% of the lost T&O/SECA transmission revenues of \$128 million a year. I&M requested recovery of these lost revenues in its Indiana rate filing in late January 2008 but does not expect to commence recovering the new rates until early 2009. Future results of operations and cash flows will continue to be adversely affected in Indiana, Michigan and Tennessee until the remaining 15% of the lost T&O/SECA transmission revenues are recovered in retail rates.

The FERC PJM and MISO Regional Transmission Rate Proceeding

In the SECA proceedings, the FERC ordered the RTOs and transmission owners in the PJM/MISO region (the Super Region) to file, by August 1, 2007, a proposal to establish a permanent transmission rate design for the Super Region effective February 1, 2008. All of the transmission owners in PJM and MISO, with the exception of AEP and one MISO transmission owner, voted to continue zonal rates in both RTOs. In September 2007, AEP filed a formal complaint proposing a highway/byway rate design be implemented for the Super Region where users pay based on their use of the transmission system. AEP argues the use of other PJM and MISO facilities by AEP is not as large as the use of AEP transmission by others in PJM and MISO. Therefore, a regional rate design change is required to recognize that the provision and use of transmission service in the Super Region is not sufficiently uniform between transmission owners and users to justify zonal rates. In January 2008, the FERC denied AEP's complaint. Management expects to file for rehearing. Should this effort be successful, AEP would reduce future retail rates in fuel or base rate proceedings. Management is unable to predict the outcome of this case.

PJM Marginal-Loss Pricing

In June 2007, in response to a 2006 FERC order, PJM revised its methodology for considering transmission line losses in generation dispatch and the calculation of locational marginal prices. Marginal-loss dispatch recognizes the varying delivery costs of transmitting electricity from individual generator locations to the places where customers consume the energy. Prior to the implementation of marginal-loss dispatch, PJM used average losses in dispatch and in the calculation of locational marginal prices. Locational marginal prices in PJM now include the real-time impact of transmission losses from individual sources to loads.

Due to the implementation of marginal-loss pricing, for the period June 1, 2007 through December 31, 2007, AEP experienced an increase in the cost of delivering energy from its generating plants to customer load zones of \$103 million, which was partially offset by cost recoveries. We believe these additional costs should be recoverable through retail and/or cost-based wholesale rates and are deferring these incremental costs as regulatory assets where recovery is probable.

APCo is presently deferring these costs for future recovery in West Virginia because, based on the advice of rate counsel, it is recoverable under the West Virginia ENEC mechanism. APCo expects to make a West Virginia ENEC filing in March 2008. For Virginia, see “Virginia Fuel Clause Filing” section of this note.

I&M filed a request to increase rates in Indiana in January 2008, which includes a request to recover these incremental PJM billings prospectively commensurate with the collection of the new rate. The IURC will probably not act on I&M’s request for collection until early 2009.

In the first quarter of 2008, CSPCo and OPCo established regulatory assets for \$12 million and \$14 million, respectively, related to these incremental PJM billings expensed in 2007 to reflect the approved recovery via the TCRR. See “Ohio Restructuring and Rate Stabilization Plans” above for a discussion of the settlement agreement which resulted in the recovery of these incremental PJM costs.

We also plan to seek recovery in Michigan and Kentucky.

Beginning in 2008, we are deferring and/or collecting approximately 75% of these incremental PJM billings. Management is unable to predict whether recovery will ultimately be approved in all of its jurisdictions.

AEP has initiated discussions with PJM regarding the impact it is experiencing from the change in methodology and will pursue a modification of such methodology through the appropriate PJM stakeholder processes.

5. EFFECTS OF REGULATION

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

Regulatory Assets:	December 31,		Notes
	2007	2006	
	(in millions)		
Current Regulatory Asset –			
Under-recovered Fuel Costs (p)	\$ 11	\$ 38	(c) (h)
SFAS 109 Regulatory Asset, Net (Note 13)	\$ 815	\$ 771	(c) (g)
SFAS 158 Regulatory Asset (Note 9)	659	875	(a) (g)
Transition Regulatory Assets – Texas, Ohio and Virginia	108	240	(a) (l)
Unamortized Loss on Reacquired Debt	92	105	(b) (j)
Virginia E&R Costs Recovery Filing (Note 4)	82	58	(c) (n)
Customer Choice Deferrals – Ohio (Note 4)	52	49	(b) (m)
Unrealized Loss on Forward Commitments	39	89	(a) (g)
Lawton Settlement (Note 4)	32	-	(b) (i)
Cook Nuclear Plant Refueling Outage Levelization	34	47	(a) (d)
Red Rock Generating Facility (Note 4)	21	-	(b) (m)
Other	265	243	(c) (g)
Total Noncurrent Regulatory Assets	\$ 2,199	\$ 2,477	
Regulatory Liabilities:			
Current Regulatory Liability –			
Over-recovered Fuel Costs (o)	\$ 64	\$ 37	(c) (h)
Regulatory Liabilities and Deferred Investment Tax Credits:			
Asset Removal Costs	\$ 1,927	\$ 1,610	(e)
Excess ARO for Nuclear Decommissioning Liability (Note 10)	362	323	(f)
Deferred Investment Tax Credits	311	332	(c) (k)
Unrealized Gain on Forward Commitments	103	181	(a) (g)
Excess Deferred State Income Taxes Due to the Phase Out of the Ohio Franchise			
Tax – Ohio (Ormet – Note 4)	43	57	(g) (a)
TCC CTC Refund	-	155	(c)
Other	206	252	(c) (g)
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	\$ 2,952	\$ 2,910	

- (a) Does not earn a return.
- (b) Amount effectively earns a return.
- (c) Includes items both earning and not earning a return.
- (d) Amortized over the period beginning with the commencement of an outage and ending with the beginning of the next outage.
- (e) The liability for removal costs, which reduces rate base and the resultant return, will be discharged as removal costs are incurred.
- (f) This is the difference in the cumulative amount of removal costs recovered through rates and the cumulative amount of ARO as measured by applying SFAS 143. This amount earns a return, accrues monthly and will be paid when the nuclear plant is decommissioned.
- (g) Recovery/refund period - various periods.
- (h) Recovery/refund period - 1 year.
- (i) Recovery/refund period - 3 years.
- (j) Recovery/refund period - up to 36 years.
- (k) Recovery/refund period - up to 79 years.
- (l) Recovery/refund period - up to 8 years.
- (m) Recovery method and timing to be determined in future proceedings.
- (n) Approximately \$49 million will be recovered over a twelve month period beginning January 1, 2008 with the remaining recovery method and timing to be determined in future proceedings.
- (o) Current Regulatory Liability - Over-recovered Fuel Costs are recorded in Other on our Consolidated Balance Sheets.
- (p) Current Regulatory Asset - Under-recovered Fuel Costs are recorded in Prepayments and Other on our Consolidated Balance Sheets.

6. COMMITMENTS, GUARANTEES AND CONTINGENCIES

We are subject to certain claims and legal actions arising in our ordinary course of business. In addition, our business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against us cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on our financial statements.

Insurance and Potential Losses

We maintain insurance coverage normal and customary for an integrated electric utility, subject to various deductibles. Our insurance includes coverage for all risks of physical loss or damage to our nonnuclear assets, subject to insurance policy conditions and exclusions. Covered property generally includes power plants, substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. Our insurance programs also generally provide coverage against loss arising from certain claims made by third parties and are in excess of retentions absorbed by us. Coverage is generally provided by a combination of a South Carolina domiciled protected-cell captive insurance company together with and/or in addition to various industry mutual and commercial insurance carriers.

See Note 10 for a discussion of nuclear exposures and related insurance.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to damage to the Cook Plant and costs of replacement power in the event of a nuclear incident at the Cook Plant. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could have a material adverse effect on our results of operations, cash flows and financial condition.

COMMITMENTS

Construction and Commitments

The AEP System has substantial construction commitments to support its operations and environmental investments. In managing the overall construction program and in the normal course of business, we contractually commit to third-party construction vendors for certain material purchases and other construction services. Aggregate construction expenditures for 2008 through 2010 for consolidated operations are estimated at approximately \$11.2 billion. The amounts for 2008, 2009 and 2010 are \$3,830 million, \$3,750 million and \$3,600 million, respectively. In addition, we expect to invest approximately \$35 million, \$70 million and \$150 million in our transmission joint ventures in 2008, 2009 and 2010, respectively. 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, weather, legal reviews and the ability to access capital.

Our subsidiaries enter into long-term contracts to acquire fuel for electric generation and transport it to our facilities. The longest contract extends to the year 2029. The contracts provide for periodic price adjustments and contain various clauses that would release the subsidiaries from their obligations under certain conditions.

Our subsidiaries purchase materials, supplies, services and property, plant and equipment under contract as part of their normal course of business. Certain supply contracts contain penalty provisions for early termination. We do not expect to incur penalty payments under these provisions that would materially affect our results of operations, cash flows or financial condition.

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 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 December 31, 2007, the maximum future payments for all the LOCs are approximately \$65 million with maturities ranging from February 2008 to December 2008.

Guarantees of Third-Party Obligations

SWEPCo

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 \$65 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 Mining Company (Sabine), an entity consolidated under FIN 46. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study, we estimate the reserves will be depleted in 2029 with final reclamation completed by 2036, at an estimated cost of approximately \$39 million. As of December 31, 2007, SWEPCo has collected approximately \$33 million through a rider for final mine closure costs, of which approximately \$16 million is recorded in Deferred Credits and Other and approximately \$17 million is recorded in Asset Retirement Obligations on our Consolidated Balance Sheets.

Sabine charges SWEPCo, its only customer, all of its costs. SWEPCo passes these costs through its fuel clause.

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. 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 \$1.4 billion (approximately \$1 billion relates to the HPL sale which remains unsettled due to the Bank of America (BOA) litigation, see “Enron Bankruptcy” section of this note). 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. Historically, at the end of the lease term the fair market value has been in excess of the unamortized balance. At December 31, 2007, the maximum potential loss for these lease agreements was approximately \$61 million (\$39 million, net of tax) assuming the fair market value of the equipment is zero at the end of the lease term.

See Note 14 for disclosure of other lease residual value guarantees.

CONTINGENCIES

Federal EPA Complaint and Notice of Violation

The Federal EPA, certain special interest groups and a number of states alleged that APCo, CSPCo, I&M and OPCo modified certain units at their coal-fired generating plants in violation of the NSR requirements of the CAA. The Federal EPA filed its complaints in U.S. District Court for the Southern District of Ohio. The alleged modifications occurred over a 20-year period.

In December 2007, the U.S. District Court approved our consent decree with the Federal EPA, the DOJ, the states and the special interest groups. The consent decree resolved all issues related to various parties' claims against us in the NSR cases.

Under the consent decree, we agreed to annual SO₂ and NO_x emission caps for sixteen coal-fired power plants located in Indiana, Kentucky, Ohio, Virginia and West Virginia. In addition to completing the installation of previously announced environmental retrofit projects at many of the plants, including the installation of flue gas desulfurization (FGD or scrubbers) equipment at Big Sandy and at Muskingum River Plants no later than the end of 2015, we agreed to install selective catalytic reduction (SCR) and FGD emissions control equipment at Rockport Plant. Unit 1 at the Rockport Plant will be retrofit no later than the end of 2017, and Unit 2 will be retrofit no later than the end of 2019. We also agreed to install selective non-catalytic reduction, a NO_x-reduction technology, no later than the end of 2009 at Clinch River Plant. We agreed to operate SCRs year round during 2008 at Mountaineer, Muskingum River and Amos Plants, and agreed to plant-specific SO₂ emission limits for the Clinch River and Kammer Plants.

Under the consent decree, we paid a \$15 million civil penalty in 2008 and provided \$36 million for environmental mitigation projects coordinated with the federal government and \$24 million to the states for environmental mitigation. We expensed these amounts in 2007.

We believe we can recover any capital and operating costs of additional pollution control equipment that may be required as a result of the consent decree through future regulated rates or market prices of electricity. If we are unable to recover such costs, it would adversely affect our future results of operations, cash flows and possibly financial condition.

Cases are still pending that could affect CSPCo's share of jointly-owned units at Beckjord and Stuart stations. The Stuart units, operated by Dayton Power and Light Company, are equipped with SCR and FGD controls. A trial on liability issues is scheduled for August 2008. The Court issued a 60-day stay to allow the parties to pursue settlement discussions. The Beckjord case is scheduled for a liability trial in May 2008. Beckjord is operated by Duke Energy Ohio, Inc.

We are unable to estimate the loss or range of loss related to any contingent liability, if any, we might have for civil penalties under the pending CAA proceedings for our jointly-owned plants. 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 market prices of electricity. If we are unable to recover such costs or if material penalties are imposed, it would adversely affect our future results of operations, cash flows and possibly financial condition.

SWEPCo Notice of Enforcement and Notice of Citizen Suit

In March 2005, two special interest groups, Sierra Club and Public Citizen, filed a complaint in Federal District Court for the Eastern District of Texas alleging violations of the CAA at SWEPCo's Welsh Plant. A trial in this matter was delayed until March 31, 2008 to allow the parties to pursue settlement discussions.

In 2004, the Texas Commission on Environmental Quality (TCEQ) issued a Notice of Enforcement to SWEPCo relating to the Welsh Plant. In April 2005, TCEQ issued an Executive Director's Report (Report) recommending the entry of an enforcement order to undertake certain corrective actions and assessing an administrative penalty of approximately \$228 thousand against SWEPCo. TCEQ filed an amended Report during the fourth quarter of 2007, eliminating certain claims and reducing the recommended penalty amount to \$122 thousand. The original Report contained a recommendation limiting 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 and to clarify the sulfur content requirement for fuels consumed at the plant. A permit alteration was issued in March 2007. The Sierra Club and Public Citizen filed a motion to overturn the permit alteration. In June 2007, TCEQ denied that motion. The permit alteration has been appealed to the Travis County District Court.

On February 8, 2008, the Federal EPA issued a Notice of Violation (NOV) based on alleged violations of a percent sulfur in fuel limitation and the heat input values listed in the previous state permit. The NOV also alleges that the permit alteration issued by TCEQ was improper. SWEPCo requested a meeting with the Federal EPA to discuss the alleged violations.

We are unable to predict the timing of any future action by TCEQ, the Federal EPA or the special interest groups or the effect of such actions on our results of operations, cash flows or financial condition.

Carbon Dioxide (CO₂) Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO₂ emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The dismissal of this lawsuit was appealed to the Second Circuit Court of Appeals. Briefing and oral argument have concluded. In April 2007, the U.S. Supreme Court issued a decision holding that the Federal EPA has authority to regulate emissions of CO₂ and other greenhouse gases under the CAA, which may impact the Second Circuit's analysis of these issues. The Second Circuit requested supplemental briefs addressing the impact of the Supreme Court's decision on this case. We believe the actions are without merit and intend to defend against the claims.

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, our generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls (PCBs) and other hazardous and nonhazardous materials. We currently incur costs to safely dispose of these substances.

Superfund addresses clean-up of hazardous substances that have been released to the environment. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. At December 31, 2007, our subsidiaries are named by the Federal EPA as a Potentially Responsible Party (PRP) for five sites for which alleged liability is unresolved. There are ten additional sites for which our subsidiaries have received information requests which could lead to PRP designation. Our subsidiaries have also been named potentially liable at two sites under state law. In those instances where we have been named a PRP or defendant, our disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on results of operations.

We evaluate the potential liability for each Superfund site separately, but several general statements can be made regarding our potential future liability. Disposal of materials at a particular site is often unsubstantiated and the quantity of materials deposited at a site was small and often nonhazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. At present, our estimates do not anticipate material cleanup costs for any of our identified Superfund sites.

TEM Litigation

We agreed to sell up to approximately 800 MW of energy to Tractebel Energy Marketing, Inc. (TEM) (now known as SUEZ Energy Marketing NA, Inc.) for a period of 20 years under a Power Purchase and Sale Agreement (PPA). Beginning May 1, 2003, OPCo tendered replacement capacity, energy and ancillary services to TEM pursuant to the PPA that TEM rejected as nonconforming.

In 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 January 2008, we reached a settlement with TEM to resolve all litigation regarding the PPA. TEM paid us \$255 million. We recorded the \$255 million as a gain in January 2008.

Enron Bankruptcy

Right to use of cushion gas agreements – In 2001, we purchased HPL from Enron. Various HPL-related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy. In connection with our acquisition of HPL, we entered into an agreement with BAM Lease Company, which granted HPL the exclusive right to use approximately 55 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 the 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. This dispute is being litigated in Texas state courts, Enron bankruptcy proceedings and in Federal courts in Texas and New York.

In 2002 and 2004, BOA filed lawsuits 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.

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 2003, AEP filed a lawsuit against BOA in the United States District Court for the Southern District of Texas. BOA led the lending syndicate involving the monetization of the cushion gas to Enron and its subsidiaries. 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 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. In April 2005, the Judge entered an order severing and transferring the declaratory judgment claims involving the right to use and cushion gas consent agreements to the Southern District of New York and retaining the four counts alleging breach of contract, fraud and negligent misrepresentation in the Southern District of Texas. HPL and BOA filed motions for summary judgment in the case pending in the Southern District of New York. Trial in federal court in Texas was continued pending a decision on the motions for summary judgment in the New York case.

In August 2007, the judge in the New York action issued a decision granting BOA summary judgment and dismissed our claims. In December 2007, the judge held that BOA is entitled to recover damages of approximately \$347 million (\$427 million including interest at December 31, 2007) less a to be determined amount BOA would have incurred to remove 55 BCF of natural gas from the Bammel storage facility. We filed a Motion for Reconsideration questioning the damage calculation. We have not determined whether we will appeal the court's decision once the court enters a final judgment. If the Court enters a final judgment adverse to us and we appeal from the judgment, we will be required under court rules to post security in the form of a bond or stand-by letter of credit covering the amount of the judgment entered against us.

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 and deferred a gain from the sale (\$380 million as of December 31, 2006) pending resolution of the Enron and BOA disputes. We expensed interest of approximately \$45 million on the damage amount in December 2007 which increased the total liability, including the previously deferred gain, to \$427 million at December 31, 2007. These amounts are included in Deferred Credits and Other on our Consolidated Balance Sheets.

Commodity trading settlement disputes – At the date of Enron's bankruptcy, certain of our subsidiaries had open trading contracts and trading accounts receivables and payables with Enron. In 2003, Enron filed two complaints, one challenging AEP's offsetting of receivables and payables and related collateral across various Enron entities and seeking payment of approximately \$125 million plus interest in connection with gas-related trading transactions and the other seeking approximately \$93 million plus interest in connection with a transaction for the sale and purchase of physical power among Enron, AEP and Allegheny Energy Supply, LLC. In 2005, the parties reached a settlement resulting in a pretax cost of approximately \$46 million.

Shareholder Lawsuits

In 2002 and 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 these actions, the plaintiffs sought recovery of an unstated amount of compensatory damages, attorney fees and costs. In July 2006, the Court entered judgment denying plaintiff's motion for class certification and dismissed all claims without prejudice. In August 2007, the appeals court reversed the trial court's decision and held that the plaintiff did have standing to pursue his claim. The appeals court remanded the case to the trial court to consider the issue of whether the plaintiff is an adequate representative for the class of plan participants. We intend to continue to defend against these claims.

Natural Gas Markets Lawsuits

In 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County California Superior Court against numerous energy companies, including AEP, 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 also filed in California and in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. AEP (or a subsidiary) is among the companies named as defendants in some of these cases. These cases are at various pre-trial stages. Several of these cases were dismissed on the basis of the filed rate doctrine. Plaintiffs in these cases appealed the decisions. In July 2007, the judge in the California cases stayed those proceedings pending a decision by the Ninth Circuit in the federal cases. In September 2007, the United States Court of Appeals for the Ninth Circuit reversed the dismissal of two of the cases and remanded those cases to the trial court. We will continue to defend each case where an AEP company is a defendant.

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 because the market for power was allegedly dysfunctional at the time such contracts were executed. In 2003, the FERC rejected the complaint. In 2006, the U.S. Court of Appeals for the Ninth Circuit reversed the FERC order and remanded the case to the FERC for further proceedings. That decision was appealed and the U.S. Supreme Court decided that it will review the Ninth Circuit’s decision in 2008. Management is unable to predict the outcome of these proceedings or their impact on future results of operations and cash flows. We have asserted claims against certain companies that sold power to us, which we resold to the Nevada utilities, seeking to recover a portion of any amounts we may owe to the Nevada utilities.

7. COMPANY-WIDE STAFFING AND BUDGET REVIEW

As a result of a 2005 company-wide staffing and budget review, we identified approximately 500 positions for elimination. We recorded pretax severance benefits expense of \$28 million, which is primarily reflected in Other Operation and Maintenance on our 2005 Consolidated Statement of Income. Approximately 95% of the expense was within the Utility Operations segment. The following table shows the total 2005 expense recorded and the activity during 2005 through 2006, which eliminated the accrual as of June 30, 2006:

	Amount (in millions)
Total Expense	\$ 28
Less: Total Payments	16
Accrual at December 31, 2005	12
Less: Total Payments	8
Less: Accrual Adjustments	4
Accrual at December 31, 2006	\$ -

The favorable 2006 accrual adjustments were recorded primarily in Other Operation and Maintenance on our 2006 Consolidated Statement of Income.

8. ACQUISITIONS, DISPOSITIONS, DISCONTINUED OPERATIONS, IMPAIRMENTS AND ASSETS HELD FOR SALE

ACQUISITIONS

2007

Darby Electric Generating Station (Utility Operations segment)

In November 2006, CSPCo agreed to purchase Darby Electric Generating Station (Darby) from DPL Energy, LLC, a subsidiary of The Dayton Power and Light Company, for \$102 million and the assumption of liabilities of \$2 million. CSPCo completed the purchase in April 2007. The Darby Plant is located near Mount Sterling, Ohio and is a natural gas, simple cycle power plant with a generating capacity of 480 MW.

Lawrenceburg Generating Station (Utility Operations segment)

In January 2007, AEGCo agreed to purchase Lawrenceburg Generating Station (Lawrenceburg) from an affiliate of Public Service Enterprise Group (PSEG) for \$325 million and the assumption of liabilities of \$3 million. AEGCo completed the purchase in May 2007. The Lawrenceburg Plant is located in Lawrenceburg, Indiana, adjacent to I&M’s Tanners Creek Plant, and is a natural gas, combined cycle power plant with a generating capacity of 1,096 MW. AEGCo sells the power to CSPCo through a FERC-approved unit power contract.

Dresden Plant (Utility Operations segment)

In August 2007, AEGCo agreed to purchase the partially completed Dresden Plant from Dominion Resources, Inc. for \$85 million and the assumption of liabilities of \$2 million. AEGCo completed the purchase in September 2007. AEGCo incurred approximately \$7 million in construction costs at the Dresden Plant in 2007 and expects to incur approximately \$175 million in additional costs (excluding AFUDC) prior to completion. The Dresden Plant is located near Dresden, Ohio and is a natural gas, combined cycle power plant. When completed in 2010, the Dresden Plant will have a generating capacity of 580 MW.

2006

None

2005

Waterford Plant (Utility Operations segment)

In May 2005, CSPCo signed a purchase-and-sale agreement with Public Service Enterprise Group Waterford Energy LLC, a subsidiary of PSEG, for the purchase of the Waterford Plant in Waterford, Ohio. The Waterford Plant is a natural gas, combined cycle power plant with a generating capacity of 821 MW. This transaction was completed in September 2005 for \$218 million and the assumption of liabilities of approximately \$2 million.

Monongahela Power Company (Utility Operations segment)

In June 2005, the PUCO ordered CSPCo to explore the purchase of the Ohio service territory of Monongahela Power Company (Monongahela Power), which included approximately 29,000 customers. In August 2005, we agreed to terms of a transaction, which included the transfer of Monongahela Power's Ohio customer base and the assets, at net book value, that serve those customers to CSPCo. This transaction was completed in December 2005 for approximately \$42 million and the assumption of liabilities of approximately \$2 million. In addition, CSPCo paid \$10 million to compensate Monongahela Power for its termination of certain litigation in Ohio. Therefore, beginning January 1, 2006, CSPCo began serving customers in this additional portion of its service territory. CSPCo's \$10 million payment was recorded as a regulatory asset and is being recovered with a carrying cost from all of CSPCo's customers over approximately 5 years. Also included in the transaction was a power purchase agreement under which Allegheny Power, Monongahela Power's parent company, provided the power requirements of the acquired customers through May 31, 2007.

Ceredo Generating Station (Utility Operations segment)

In August 2005, APCo signed a purchase-and-sale agreement with Reliant Energy for the purchase of the Ceredo Generating Station located near Ceredo, West Virginia. The Ceredo Generating Station is a natural gas, simple cycle power plant with a generating capacity of 505 MW. This transaction was completed in December 2005 for \$100 million.

DISPOSITIONS

2007

Electric Transmission Texas LLC (ETT) (Utility Operations segment)

In December 2007, TCC contributed \$70 million of transmission facilities to ETT, a newly-formed affiliated entity which will own and operate transmission facilities in ERCOT. Through a series of transactions, we then sold, at net book value, a 50% equity ownership interest in ETT to a subsidiary of MidAmerican Energy Holdings Company.

Texas Plants – Oklaunion Power Station (Utility Operations segment)

In February 2007, TCC sold its 7.81% share of Oklaunion Power Station to the Public Utilities Board of the City of Brownsville for \$43 million plus capital adjustments. The sale did not have an impact on our results of operations nor do we expect the remaining litigation related to the sale to have a material effect on our results of operations.

Intercontinental Exchange, Inc. (ICE) (All Other)

See “Intercontinental Exchange, Inc. (ICE) Initial Public Offering” section of 2005 dispositions for information regarding sales in 2007.

Sweeny Cogeneration Plant (Generation and Marketing segment)

In October 2007, we sold our 50% equity interest in the Sweeny Cogeneration Plant (Sweeny) to ConocoPhillips for approximately \$80 million, including working capital and the buyer’s assumption of project debt. The Sweeny Cogeneration Plant is a 480 MW cogeneration plant located within ConocoPhillips’ Sweeny refinery complex southwest of Houston, Texas. We were the managing partner of the plant, which is co-owned by General Electric Company. As a result of the sale, we recognized a \$47 million pretax gain (\$30 million, net of tax) in the fourth quarter of 2007, which is reflected in Gain on Disposition of Equity Investments, Net on our 2007 Consolidated Statement of Income.

In addition to the sale of our interest in Sweeny, we agreed to separately sell our purchase power contract for our share of power generated by Sweeny through 2014 for \$11 million to ConocoPhillips. ConocoPhillips also agreed to assume certain related third-party power obligations. These transactions were completed in conjunction with the sale of our 50% equity interest in October 2007. As a result of this sale, we recognized an \$11 million pretax gain (\$7 million, net of tax) in the fourth quarter of 2007, which is included in Other revenues on our 2007 Consolidated Statement of Income. In the fourth quarter of 2007, we recognized a total of \$58 million in pretax gains (\$37 million, net of tax).

2006

Compresion Bajio S de R.L. de C.V. (All Other)

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, which resulted in a pretax other-than-temporary impairment charge of approximately \$7 million. The impairment amount is classified in Investment Value Losses on our 2005 Consolidated Statement of Income. We completed the sale in February 2006 for approximately \$29 million with no effect on our 2006 results of operations.

Plaquemine Cogeneration Facility (All Other)

In August 2006, we reached an agreement to sell our Plaquemine Cogeneration Facility (the Facility) to Dow Chemical Company (Dow) for \$64 million. We recorded a pretax impairment of \$209 million (\$136 million, net of tax) in the third quarter of 2006 based on the terms of the agreement to sell the Facility to Dow. We recorded the impairment in Asset Impairments and Other Related Charges on our 2006 Consolidated Statement of Income. The Facility does not meet the criteria for discontinued operations reporting.

We completed the sale in the fourth quarter of 2006. Excluding the 2006 impairment of \$209 million discussed above, the effect of the sale on our 2006 results of operations was not significant. In addition to the cash proceeds, the sale agreement allows us to participate in gross margin sharing on the Facility for five years. Under this agreement, we recorded gross margin sharing of \$10 million during 2007. These margins were recorded in Gain on Disposition of Assets, Net on our 2007 Consolidated Statement of Income. As a result of the sale, Dow reduced an existing below-current-market long-term power supply contract with us in Texas by 50 MW and we retained the right to any judgment paid by TEM for breaching the original Power Purchase and Sale Agreement. See “TEM Litigation” section of Note 6.

Intercontinental Exchange, Inc. (ICE) Initial Public Offering (All Other)

See the following 2005 disclosure “Intercontinental Exchange, Inc. (ICE) Initial Public Offering” for information regarding sales in 2006.

2005

Intercontinental Exchange, Inc. (ICE) Initial Public Offering (All Other)

In November 2000, we made our initial investment in ICE. An initial public offering (IPO) occurred on November 15, 2005. We sold approximately 2.1 million shares (71% of our investment in ICE) in the fourth quarter of 2005 and recognized a \$47 million pretax gain (\$30 million, net of tax). During 2006, we sold approximately 600,000 shares and recognized a \$39 million pretax gain (\$25 million, net of tax). In March 2007, we sold 130,000 shares of ICE and recognized a \$16 million pretax gain (\$10 million, net of tax). We recorded the gains in Interest and Investment Income on our Consolidated Statements of Income. Our investment of approximately 138,000 and 268,000 shares as of December 31, 2007 and 2006, respectively, is recorded in Other Temporary Investments on our Consolidated Balance Sheets.

Houston Pipe Line Company LP (HPL) (All Other)

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. We indemnified the buyer of HPL against any damages resulting from the BOA litigation up to the purchase price. 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 the cushion gas. As the result of ongoing litigation regarding the cushion gas agreement (see “Enron Bankruptcy” section of Note 6), the determination of the gain on sale and the recognition of the gain on sale were deferred pending the resolution of the BOA dispute (\$380 million at December 31, 2006). In December 2007, the amount recorded was increased to \$427 million by a charge to interest expense of approximately \$45 million to reflect a Federal court ruling.

The HPL operations do 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 hold forward gas contracts, with expirations through 2010, not sold with the gas pipeline and storage assets. We manage the commodity price risk associated with these forward gas contracts to limit our price risk exposure principally by entering into equal and offsetting contracts. For the year ended December 31, 2007, there was an immaterial change in the mark-to-market value of these contracts.

Pacific Hydro Limited (All Other)

In March 2005, we signed an agreement with Acciona, S.A. for the sale of our equity investment in Pacific Hydro Limited for approximately \$88 million. The sale was completed in July 2005 and we recognized a pretax gain of \$56 million. This gain is classified in Gain on Disposition of Equity Investments, Net on our 2005 Consolidated Statement of Income.

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 Centrica and us 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-sale agreement and was amended through a series of agreements that we and Centrica entered in March 2005. 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. We received payments of \$20 million and \$70 million in 2007 and 2006, respectively for our share of earnings applicable to 2006 and 2005, respectively, under the ESM. The payments are reflected in Gain on Disposition of Assets, Net on our Consolidated Statements of Income.

Texas Plants – South Texas Project (Utility Operations segment)

In February 2004, we signed an agreement to sell TCC's 25.2% share of the STP nuclear plant to an unrelated party for approximately \$333 million, subject to closing adjustments. In June 2004, we received notice from co-owners of their decisions to exercise their rights of first refusal with terms similar to the original agreement. In September 2004, we entered into sales agreements with two of our nonaffiliated co-owners for the sale of TCC's 25.2% share of the STP nuclear plant. The sale was completed for approximately \$315 million and the assumption of liabilities of \$22 million in May 2005 and did not have a significant effect on our results of operations. The plant did not meet the "component-of-an-entity" criteria because it did not have cash flows that could be clearly distinguished operationally and because it did not operate individually, but rather as a part of the AEP System.

DISCONTINUED OPERATIONS

Management periodically assesses our overall business model and makes decisions regarding our continued support and funding of our various businesses and operations. When it is determined that we will seek to exit a particular business or activity and we have met the accounting requirements for reclassification, we will reclassify those businesses or activities as discontinued operations. The assets and liabilities of these discontinued operations are classified in Assets Held for Sale and Liabilities Held for Sale until the time that they are sold.

Certain of our operations were determined to be discontinued operations and are classified as such in 2007, 2006 and 2005. Results of operations of these businesses are classified as shown in the following table:

	SEE- BOARD (a)	LIG (b)	U.K. Generation (c)	Total
	(in millions)			
2007 Revenue	\$ -	\$ -	\$ -	\$ -
2007 Pretax Income	-	-	7	7
2007 Earnings, Net of Tax	4	-	20	24
2006 Revenue	\$ -	\$ -	\$ -	\$ -
2006 Pretax Income	-	-	9	9
2006 Earnings, Net of Tax	5	-	5	10
2005 Revenue (Expense)	\$ 13	\$ -	\$ (7)	\$ 6
2005 Pretax Income (Loss)	10	-	(13)	(3)
2005 Earnings (Loss), Net of Tax	24	5	(2)	27

- (a) Relates to purchase price true-up adjustments and tax adjustments from the sale of SEEBOARD.
- (b) Includes LIG Pipeline Company and subsidiaries and Jefferson Island Storage & Hub LLC. The 2005 amounts relate to purchase price true-up adjustments and tax adjustments from the sale.
- (c) The 2007 and 2006 amounts relate to a release of accrued liabilities for the London office sublease and tax adjustments from the sale. The 2005 amounts relate to purchase price true-up adjustments and tax adjustments from the sale. In July 2004, we completed the sale of our U.K. Operations, which included the sale of two coal-fired generation plants, coal assets and a number of commodities contracts.

ASSET IMPAIRMENTS, INVESTMENT VALUE LOSSES AND OTHER RELATED CHARGES

2007

None

2006

We recorded a pretax impairment of assets totaling \$209 million as a result of the terms of our agreement to sell the Plaquemine Cogeneration Facility to Dow. See “Plaquemine Cogeneration Facility” section of this note for additional information regarding this sale.

2005

We recorded pretax impairments of assets totaling \$46 million (\$39 million related to asset impairments and \$7 million related to an equity investment impairment) that reflected our decision to retire two generation units and our decision to exit noncore businesses and other factors as follows:

Conesville Units 1 and 2 (Utility Operations segment)

In the third quarter of 2005, following management’s extensive review of the commercial viability of our generation fleet, management committed to a plan to retire CSPCo’s Conesville Units 1 and 2 before the end of their previously estimated useful lives. As a result, Conesville Units 1 and 2 were retired as of the third quarter of 2005.

We recognized a pretax charge of approximately \$39 million in 2005 related to our decision to retire the units. The impairment amount is classified in Asset Impairments and Other Related Charges on our 2005 Consolidated Statement of Income.

Compresion Bajio S de R.L. de C.V. (All Other)

In September 2005, a pretax other-than-temporary impairment charge of approximately \$7 million was recognized based on an indicative offer for the sale of our 50% interest in Bajio. The 2005 impairment amount is classified as Investment Value Losses on our Consolidated Statements of Income. The sale was completed in February 2006 with no significant effect on our 2006 results of operations.

The categories of impairments and gains on dispositions include:

	Years Ended December 31,		
	2007	2006	2005
<u>Asset Impairments and Other Related Charges (Pretax)</u>	(in millions)		
Plaquemine Cogeneration Facility	\$ -	\$ 209	\$ -
Conesville Units 1 and 2	-	-	39
Total	<u>\$ -</u>	<u>\$ 209</u>	<u>\$ 39</u>
<u>Gain (Loss) on Disposition of Assets, Net (Pretax)</u>			
Texas REPs	\$ 20	\$ 70	\$ 112
Revenue Sharing on Plaquemine Cogeneration Facility	10	-	-
Gain on Sale of Land Rights and Other Miscellaneous Property, Plant and Equipment	11	(1)	8
Total	<u>\$ 41</u>	<u>\$ 69</u>	<u>\$ 120</u>
<u>Investment Value Losses (Pretax)</u>			
Bajio	\$ -	\$ -	\$ 7
<u>Gain on Disposition of Equity Investments, Net (Pretax)</u>			
Sweeny Cogeneration Plant	\$ 47	\$ -	\$ -
Pacific Hydro Limited	-	-	56
Other	-	3	-
Total	<u>\$ 47</u>	<u>\$ 3</u>	<u>\$ 56</u>

ASSETS HELD FOR SALE

Texas Plants – Oklaunion Power Station (Utility Operations segment)

In February 2007, TCC sold its 7.81% share of Oklaunion Power Station to the Public Utilities Board of the City of Brownsville. We classified TCC's assets related to the Oklaunion Power Station in Assets Held for Sale on our Consolidated Balance Sheets at December 31, 2006. The plant did not meet the "component-of-an-entity" criteria because it does not have cash flows that can be clearly distinguished operationally and because it does not operate individually, but rather as a part of the AEP System.

Assets Held for Sale at December 31, 2007 and 2006 were as follows:

Texas Plants	December 31,	
	2007	2006
	(in millions)	
Other Current Assets	\$ -	\$ 1
Property, Plant and Equipment, Net	-	43
Total Assets Held for Sale	\$ -	\$ 44

9. **BENEFIT PLANS**

We sponsor two qualified pension plans and two nonqualified pension plans. A substantial majority of our employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. We sponsor other postretirement benefit plans to provide medical and life insurance benefits for retired employees.

We adopted SFAS 158 as of December 31, 2006. It requires employers to fully recognize the obligations associated with defined benefit pension plans and OPEB plans, which include retiree healthcare, in their balance sheets. Previous standards required an employer to disclose the complete funded status of its plan only in the notes to the financial statements and provided that an employer delay recognition of certain changes in plan assets and obligations that affected the costs of providing benefits resulting in an asset or liability that often differed from the plan's funded status. SFAS 158 requires a defined benefit pension or postretirement plan sponsor to (a) recognize in its statement of financial position an asset for a plan's overfunded status or a liability for the plan's underfunded status, (b) measure the plan's assets and obligations that determine its funded status as of the end of the employer's fiscal year and (c) recognize, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year but are not recognized as a component of net periodic benefit cost pursuant to previous standards. It also requires an employer to disclose additional information on how delayed recognition of certain changes in the funded status of a defined benefit pension or OPEB plan affects net periodic benefit costs for the next fiscal year. We recorded a SFAS 71 regulatory asset for qualifying SFAS 158 costs of our regulated operations that for ratemaking purposes will be deferred for future recovery. The effect of this standard on our 2006 financial statements was a pretax AOCI adjustment of \$1,236 million that was offset by a SFAS 71 regulatory asset of \$875 million and a deferred income tax asset of \$126 million resulting in a net of tax AOCI equity reduction of \$235 million.

SFAS 158 requires adjustment of pretax AOCI at the end of each year, for both underfunded and overfunded defined benefit pension and OPEB plans, to an amount equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction and deferred gains result in an AOCI equity addition. The year-end AOCI measure can be volatile based on fluctuating investment returns and discount rates.

The following tables provide a reconciliation of the changes in the plans' projected benefit obligations and fair value of assets over the two-year period ending at the plan's measurement date of December 31, 2007, and their funded status as of December 31 of each year:

Projected Pension Obligations, Plan Assets, Funded Status as of December 31, 2007 and 2006

	Pension Plans		Other Postretirement Benefit Plans	
	2007	2006	2007	2006
Change in Projected Benefit Obligation	(in millions)			
Projected Obligation at January 1	\$ 4,108	\$ 4,347	\$ 1,818	\$ 1,831
Service Cost	96	97	42	39
Interest Cost	235	231	104	102
Actuarial Gain	(64)	(293)	(91)	(55)
Plan Amendments	18	2	-	-
Benefit Payments	(284)	(276)	(130)	(112)
Participant Contributions	-	-	22	21
Medicare Subsidy	-	-	8	(8)
Projected Obligation at December 31	\$ 4,109	\$ 4,108	\$ 1,773	\$ 1,818
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets at January 1	\$ 4,346	\$ 4,143	\$ 1,302	\$ 1,172
Actual Return on Plan Assets	435	470	115	127
Company Contributions	7	9	91	94
Participant Contributions	-	-	22	21
Benefit Payments	(284)	(276)	(130)	(112)
Fair Value of Plan Assets at December 31	\$ 4,504	\$ 4,346	\$ 1,400	\$ 1,302
Funded (Underfunded) Status at December 31	\$ 395	\$ 238	\$ (373)	\$ (516)

Amounts Recognized on the Balance Sheets as of December 31, 2007 and 2006

	Pension Plans		Other Postretirement Benefit Plans	
	2007	2006	2007	2006
	(in millions)			
Employee Benefits and Pension Assets – Prepaid Benefit Costs	\$ 482	\$ 320	\$ -	\$ -
Other Current Liabilities – Accrued Short-term Benefit Liability	(8)	(8)	(4)	(5)
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(79)	(74)	(369)	(511)
Funded (Underfunded) Status	\$ 395	\$ 238	\$ (373)	\$ (516)

SFAS 158 Amounts Recognized in Accumulated Other Comprehensive Income (AOCI) as of December 31, 2007 and 2006

Components	Pension Plans		Other Postretirement Benefit Plans	
	2007	2006	2007	2006
	(in millions)			
Net Actuarial Loss	\$ 534	\$ 759	\$ 231	\$ 354
Prior Service Cost (Credit)	14	(5)	4	4
Transition Obligation	-	-	97	124
Pretax AOCI	\$ 548	\$ 754	\$ 332	\$ 482
Recorded as				
Regulatory Assets	\$ 453	\$ 582	\$ 204	\$ 293
Deferred Income Taxes	33	60	45	66
Net of Tax AOCI	62	112	83	123
Pretax AOCI	\$ 548	\$ 754	\$ 332	\$ 482

Components of the Change in Plan Assets and Benefit Obligations Recognized in Pretax AOCI during the year ended December 31, 2007 are as follows:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
2007 Actuarial Gain	\$ (166)	\$ (111)
Amortization of Actuarial Loss	(59)	(12)
2007 Prior Service Cost	19	-
Amortization of Transition Obligation	-	(27)
Total 2007 Pretax AOCI Change	\$ (206)	\$ (150)

Pension and Other Postretirement Plans' Assets

The asset allocations for our pension plans at the end of 2007 and 2006, and the target allocation for 2008, by asset category, are as follows:

Asset Category	Target Allocation	Percentage of Plan Assets at Year End	
	2008	2007	2006
Equity Securities	55%	57%	63%
Real Estate	5%	6%	6%
Debt Securities	39%	36%	26%
Cash and Cash Equivalents	1%	1%	5%
Total	100%	100%	100%

The asset allocations for our other postretirement benefit plans at the end of 2007 and 2006, and target allocation for 2008, by asset category, are as follows:

Asset Category	Target Allocation	Percentage of Plan Assets at Year End	
	2008	2007	2006
Equity Securities	66%	62%	66%
Debt Securities	33%	35%	32%
Cash and Cash Equivalents	1%	3%	2%
Total	100%	100%	100%

Our investment strategy for our employee benefit trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the interest rate sensitivity of the plans' assets relative to the plans' liabilities. To minimize investment risk, our employee benefit trust funds are broadly diversified among classes of assets, investment strategies and investment managers. We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation when considered appropriate. Our investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. Our investment policies prohibit investment in AEP securities, with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies.

The value of our pension plans' assets increased to \$4.5 billion at December 31, 2007 from \$4.3 billion at December 31, 2006. The qualified plans paid \$277 million in benefits to plan participants during 2007 (nonqualified plans paid \$7 million in benefits). The value of AEP's Postretirement Plans' assets increased to \$1.4 billion in December 31, 2007 from \$1.3 billion at December 31, 2006. The Postretirement Plans paid \$130 million in benefits to plan participants during 2007.

We base our determination of pension expense or income on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded.

	December 31,	
	2007	2006
Accumulated Benefit Obligation	(in millions)	
Qualified Pension Plans	\$ 3,914	\$ 3,861
Nonqualified Pension Plans	77	78
Total	\$ 3,991	\$ 3,939

For our underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation, and fair value of plan assets of these plans at December 31, 2007 and 2006 were as follows:

	Underfunded Pension Plans	
	December 31,	
	2007	2006
	(in millions)	
Projected Benefit Obligation	\$ 81	\$ 82
Accumulated Benefit Obligation	\$ 77	\$ 78
Fair Value of Plan Assets	-	-
Accumulated Benefit Obligation Exceeds the Fair Value of Plan Assets	\$ 77	\$ 78

Actuarial Assumptions for Benefit Obligations

The weighted-average assumptions as of December 31, used in the measurement of our benefit obligations are shown in the following tables:

Assumption	Pension Plans		Other Postretirement Benefit Plans	
	December 31,		December 31,	
	2007	2006	2007	2006
Discount Rate	6.00%	5.75%	6.20 %	5.85%
Rate of Compensation Increase	5.90% (a)	5.90% (a)	N/A	N/A

- (a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

N/A = Not Applicable

To determine a discount rate, we use a duration-based method by constructing a hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's Aa bond index with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan.

For 2007, the rate of compensation increase assumed varies with the age of the employee, ranging from 5% per year to 11.5% per year, with an average increase of 5.9%.

Estimated Future Benefit Payments and Contributions

Information about the 2008 expected cash flows for the pension (qualified and nonqualified) and other postretirement benefit plans is as follows:

Employer Contribution	Pension Plans		Other Postretirement Benefit Plans	
	(in millions)			
Required Contributions (a)	\$	8	\$	4
Additional Discretionary Contributions		-		73

- (a) Contribution required to meet minimum funding requirement per the U.S. Department of Labor plus direct payments for unfunded benefits.

The contribution to the pension plans is based on the minimum amount required by the U.S. Department of Labor and the amount to pay unfunded nonqualified benefits. The contribution to the other postretirement benefit plans is generally based on the amount of the other postretirement benefit plans' periodic benefit cost for accounting purposes as provided for in agreements with state regulatory authorities, plus the additional discretionary contribution of our Medicare subsidy receipts.

The table below reflects the total benefits expected to be paid from the plan or from our assets, including both our share of the benefit cost and the participants' share of the cost, which is funded by participant contributions to the plan. Medicare subsidy receipts are shown in the year of the corresponding benefit payments, even though actual cash receipts are expected early in the following year. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates, and variances in actuarial results. The estimated payments for pension benefits and other postretirement benefits are as follows:

	Pension Plans	Other Postretirement Benefit Plans	
	Pension Payments	Benefit Payments	Medicare Subsidy Receipts
		(in millions)	
2008	\$ 356	\$ 111	\$ (10)
2009	362	121	(11)
2010	363	131	(11)
2011	363	141	(12)
2012	368	149	(13)
Years 2013 to 2017, in Total	1,861	864	(82)

Components of Net Periodic Benefit Cost

The following table provides the components of our net periodic benefit cost for the plans for fiscal years 2007, 2006 and 2005:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2007	2006	2005	2007	2006	2005
	(in millions)					
Service Cost	\$ 96	\$ 97	\$ 93	\$ 42	\$ 39	\$ 42
Interest Cost	235	231	228	104	102	107
Expected Return on Plan Assets	(340)	(335)	(314)	(104)	(94)	(92)
Amortization of Transition Obligation	-	-	-	27	27	27
Amortization of Prior Service Cost (Credit)	-	(1)	(1)	-	-	-
Amortization of Net Actuarial Loss	59	79	55	12	22	25
Net Periodic Benefit Cost	50	71	61	81	96	109
Capitalized Portion	(14)	(21)	(17)	(25)	(27)	(33)
Net Periodic Benefit Cost Recognized as Expense	\$ 36	\$ 50	\$ 44	\$ 56	\$ 69	\$ 76

Estimated amounts expected to be amortized to net periodic benefit costs from pretax accumulated other comprehensive income during 2008 are shown in the following table:

	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Net Actuarial Loss	\$ 26	\$ 5
Prior Service Cost	1	1
Transition Obligation	-	27
Total Estimated 2008 Pretax AOCI Amortization	\$ 27	\$ 33

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions as of January 1, used in the measurement of our benefit costs are shown in the following tables:

	Pension Plans			Other Postretirement Benefit Plans		
	2007	2006	2005	2007	2006	2005
Discount Rate	5.75%	5.50%	5.50%	5.85%	5.65%	5.80%
Expected Return on Plan Assets	8.50%	8.50%	8.75%	8.00%	8.00%	8.37%
Rate of Compensation Increase	5.90%	5.90%	3.70%	N/A	N/A	N/A

The expected return on plan assets for 2007 was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation, and current prospects for economic growth.

The health care trend rate assumptions as of January 1, used for other postretirement benefit plans measurement purposes are shown below:

Health Care Trend Rates:	2007	2006
Initial	7.5 %	8.0 %
Ultimate	5.0 %	5.0 %
Year Ultimate Reached	2012	2009

Assumed health care cost trend rates have a significant effect on the amounts reported for the other postretirement benefit health care plans. A 1% change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(in millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	\$ 19	\$ (16)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	185	(154)

AEP Savings Plans

We sponsor various defined contribution retirement savings plans for substantially all employees who are not members of the United Mine Workers of America (UMWA). These plans offer participants an opportunity to contribute a portion of their pay, include features under Section 401(k) of the Internal Revenue Code and provide for company matching contributions. Our matching contributions to the plan are 75% of the first 6% of eligible compensation contributed by the employee. The cost for contributions to these plans totaled \$66 million in 2007, \$62 million in 2006 and \$57 million in 2005.

UMWA Benefits

We provide UMWA pension, health and welfare benefits for certain unionized mining employees, retirees, and their survivors who meet eligibility requirements. UMWA trustees make final interpretive determinations with regard to all benefits. The pension benefits are administered by UMWA trustees and contributions are made to their trust funds.

The health and welfare benefits are administered by us and benefits are paid from our general assets. Contributions were not material in 2007, 2006 and 2005.

10. NUCLEAR

I&M owns and operates the two-unit 2,110 MW Cook Plant under licenses granted by the NRC. We have a significant future financial commitment to safely dispose of SNF and to decommission and decontaminate the plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. The operation of a nuclear facility also involves special risks, potential liabilities and specific regulatory and safety requirements. Should a nuclear incident occur at any nuclear power plant in the U.S., the resultant liability could be substantial. By agreement, I&M is partially liable, together with all other electric utility companies that own nuclear generating units, for a nuclear power plant incident at any nuclear plant in the U.S.

Decommissioning and Low Level Waste Accumulation Disposal

The cost to decommission a nuclear plant is affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of the Cook Plant. The estimated cost of decommissioning and disposal of low-level radioactive waste for the Cook Plant ranges from \$733 million to \$1.3 billion in 2006 nondiscounted dollars. Our most recent decommissioning study was performed in 2006. The wide range is caused by variables in assumptions. I&M recovers estimated decommissioning costs for the Cook Plant in its rates. The amount recovered in rates was \$32 million in 2007, \$30 million in 2006 and \$27 million in 2005. Decommissioning costs recovered from customers are deposited in external trusts.

I&M deposited an additional \$4 million in 2007, 2006 and 2005 in its decommissioning trust under funding provisions approved by regulatory commissions. At December 31, 2007, the total decommissioning trust fund balance was approximately \$1.1 billion. Trust fund earnings increase the fund assets and decrease the amount remaining to be recovered from ratepayers. The decommissioning costs (including interest, unrealized gains and losses and expenses of the trust funds) increase or decrease the recorded liability.

I&M continues to work with regulators and customers to recover the remaining estimated costs of decommissioning the Cook Plant. However, future results of operations, cash flows and possibly financial condition would be adversely affected if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

SNF Disposal

The Federal government is responsible for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one mill per KWH for fuel consumed after April 6, 1983 at the Cook Plant is being collected from customers and remitted to the U.S. Treasury. At December 31, 2007, fees and related interest of \$259 million for fuel consumed prior to April 7, 1983 at the Cook Plant have been recorded as Long-term Debt and funds collected from customers along with related earnings totaling \$285 million to pay the fee are recorded as part of Spent Nuclear Fuel and Decommissioning Trust. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program.

Trust Assets for Decommissioning and SNF Disposal

We record securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF at market value. We classify securities in the trust funds as available-for-sale due to their long-term purpose. As discussed in the "Nuclear Trust Funds" section of Note 1, we record unrealized gains and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. The gains, losses or other-than-temporary impairments shown below did not affect earnings or AOCI. The trust assets are recorded by jurisdiction and may not be used for another jurisdictions' liabilities. Regulatory approval is required to withdraw decommissioning funds.

The following is a summary of nuclear trust fund investments at December 31:

	December 31,					
	2007			2006		
	Estimated Fair Value	Gross Unrealized Gains	Other-Than- Temporary Impairments	Estimated Fair Value	Gross Unrealized Gains	Other-Than- Temporary Impairments
	(in millions)					
Cash	\$ 22	\$ -	\$ -	\$ 24	\$ -	\$ -
Debt Securities	823	27	(6)	750	18	(8)
Equity Securities	502	205	(11)	474	192	(4)
Spent Nuclear Fuel and Decommissioning Trusts	<u>\$ 1,347</u>	<u>\$ 232</u>	<u>\$ (17)</u>	<u>\$ 1,248</u>	<u>\$ 210</u>	<u>\$ (12)</u>

Proceeds from sales of nuclear trust fund investments were \$696 million, \$631 million and \$706 million in 2007, 2006 and 2005, respectively. Purchases of nuclear trust fund investments were \$777 million, \$692 million and \$761 million in 2007, 2006 and 2005, respectively.

Gross realized gains from the sales of nuclear trust fund investments were \$15 million, \$7 million and \$13 million in 2007, 2006 and 2005, respectively. Gross realized losses from the sales of nuclear trust fund investments were \$5 million, \$7 million and \$17 million in 2007, 2006 and 2005, respectively.

The fair value of debt securities held in the nuclear trust funds, summarized by contractual maturities, at December 31, 2007 was as follows:

	Fair Value of Debt Securities (in millions)
Within 1 year	\$ 38
1 year – 5 years	205
5 years – 10 years	231
After 10 years	349
Total	<u>\$ 823</u>

Nuclear Incident Liability

I&M carries insurance coverage for property damage, decommissioning and decontamination at the Cook Plant in the amount of \$1.8 billion. I&M purchases \$1 billion of excess coverage for property damage, decommissioning and decontamination. Additional insurance provides coverage for extra costs resulting from a prolonged accidental outage. I&M utilizes an industry mutual insurer for the placement of this insurance coverage. Participation in this mutual insurance requires a contingent financial obligation of up to \$39 million for I&M which is assessable if the insurer's financial resources would be inadequate to pay for losses.

The Price-Anderson Act, extended through December 31, 2025, establishes insurance protection for public liability arising from a nuclear incident at \$10.8 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides \$300 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of \$101 million on each licensed reactor in the U.S. payable in annual installments of \$15 million. As a result, I&M could be assessed \$202 million per nuclear incident payable in annual installments of \$30 million. The number of incidents for which payments could be required is not limited.

In the event of an incident of a catastrophic nature, we are initially covered for the first \$300 million through commercially available insurance. The next level of liability coverage of up to \$10.5 billion would be covered by claims made under the Price-Anderson Act. If the liability were in excess of amounts recoverable from insurance and retrospective claim payments made under the Price-Anderson Act, we would seek to recover those amounts from customers through rate increases. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery from customers is not possible, results of operations, cash flows and financial condition could be adversely affected.

11. BUSINESS SEGMENTS

Our primary business strategy and the core of our business focus on our electric utility operations. Within our Utility Operations segment, we centrally dispatch all generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. Generation/supply in Ohio continues to have commission-determined rates transitioning from cost-based to market-based rates. The legislature in Ohio is currently considering possibly returning to some form of cost-based rate-regulation or a hybrid form of rate-regulation for generation. While our Utility Operations segment remains our primary business segment, other segments include our MEMCO Operations segment with significant barging activities and our Generation and Marketing segment, which includes our nonregulated generating, marketing and risk management activities in the ERCOT market area. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

Our reportable 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.

MEMCO Operations

- Barging operations that annually transport approximately 35 million tons of coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers. Approximately 39% of the barging is for agricultural products, 30% for coal, 14% for steel and 17% for other commodities.

Generation and Marketing

- Wind farms and marketing and risk management activities primarily in ERCOT. Our 50% interest in Sweeny Cogeneration Plant was sold in October 2007. See “Sweeny Cogeneration Plant” section of Note 8.

The remainder of our company’s activities is presented as All Other. While not considered a business segment, All Other includes:

- Parent company’s guarantee revenue received from affiliates, interest income and interest expense and other nonallocated costs.
- Tax and interest expense adjustments related to our UK operations and SEEBOARD, which were sold in 2004 and 2002, respectively.
- Our gas pipeline and storage operations, which were sold in 2004 and 2005.
- Other energy supply related businesses, including the Plaquemine Cogeneration Facility, which was sold in 2006.

The tables below present our reportable segment information for the years ended December 31, 2007, 2006 and 2005 and balance sheet information as of December 31, 2007 and 2006. These amounts include certain estimates and allocations where necessary.

		Nonutility Operations				
	Utility Operations	MEMCO Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)		
Year Ended December 31, 2007						
Revenues from:						
External Customers	\$ 12,101 (e)	\$ 523	\$ 708	\$ 48	\$ -	\$ 13,380
Other Operating Segments	554 (e)	14	(406)	(13)	(149)	-
Total Revenues	<u>\$ 12,655</u>	<u>\$ 537</u>	<u>\$ 302</u>	<u>\$ 35</u>	<u>\$ (149)</u>	<u>\$ 13,380</u>
Depreciation and Amortization	\$ 1,483	\$ 11	\$ 29	\$ 2	\$ (12)(b)	\$ 1,513
Interest Income	21	-	3	81	(70)	35
Interest Expense	787	5	28	108	(87)(b)	841
Income Tax Expense (Credit)	486	35	5	(10)	-	516
Income (Loss) Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	\$ 1,031	\$ 61	\$ 67	\$ (15)	\$ -	\$ 1,144
Discontinued Operations, Net of Tax	-	-	-	24	-	24
Extraordinary Loss, Net of Tax	(79)	-	-	-	-	(79)
Net Income	<u>\$ 952</u>	<u>\$ 61</u>	<u>\$ 67</u>	<u>\$ 9</u>	<u>\$ -</u>	<u>\$ 1,089</u>
Gross Property Additions	\$ 4,050	\$ 12	\$ 2	\$ 4(c)	\$ -	\$ 4,068

		Nonutility Operations					
	Utility Operations	MEMCO Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated	
				(in millions)			
Year Ended December 31, 2006							
Revenues from:							
External Customers	\$ 12,066	\$ 520	\$ 62	\$ (26)	\$ -	\$ 12,622	
Other Operating Segments	(55)	12	-	97	(54)	-	
Total Revenues	<u>\$ 12,011</u>	<u>\$ 532</u>	<u>\$ 62</u>	<u>\$ 71</u>	<u>\$ (54)</u>	<u>\$ 12,622</u>	
Depreciation and Amortization	\$ 1,435	\$ 11	\$ 17	\$ 4	\$ -	\$ 1,467	
Interest Income	36	-	2	91	(68)	61	
Interest Expense	667	4	11	118	(68)	732	
Income Tax Expense (Credit)	543	42	(19)	(81)	-	485	
Income (Loss) Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	\$ 1,028	\$ 80	\$ 12	\$ (128)	\$ -	\$ 992	
Discontinued Operations, Net of Tax	-	-	-	10	-	10	
Net Income (Loss)	<u>\$ 1,028</u>	<u>\$ 80</u>	<u>\$ 12</u>	<u>\$ (118)</u>	<u>\$ -</u>	<u>\$ 1,002</u>	
Gross Property Additions	\$ 3,494	\$ 7	\$ 1	\$ 26(c)	\$ -	\$ 3,528	

	Nonutility Operations					
	Utility Operations	MEMCO Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
	(in millions)					
Year Ended December 31, 2005						
Revenues from:						
External Customers	\$ 11,157	\$ 344	\$ 73	\$ 537	\$ -	\$ 12,111
Other Operating Segments	232	11	-	(174)	(69)	-
Total Revenues	<u>\$ 11,389</u>	<u>\$ 355</u>	<u>\$ 73</u>	<u>\$ 363</u>	<u>\$ (69)</u>	<u>\$ 12,111</u>
Depreciation and Amortization	\$ 1,315	\$ 11	\$ 17	\$ 5	\$ -	\$ 1,348
Interest Income	31	-	2	80	(54)	59
Interest Expense	588	3	16	144	(54)	697
Income Tax Expense (Credit)	475	10	(28)	(27)	-	430
Income (Loss) Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Changes	\$ 1,018	\$ 21	\$ 16	\$ (26)	\$ -	\$ 1,029
Discontinued Operations, Net of Tax	-	-	-	27	-	27
Extraordinary Loss, Net of Tax	(225)	-	-	-	-	(225)
Cumulative Effect of Accounting Change, Net of Tax	(17)	-	-	-	-	(17)
Net Income	<u>\$ 776</u>	<u>\$ 21</u>	<u>\$ 16</u>	<u>\$ 1</u>	<u>\$ -</u>	<u>\$ 814</u>
Gross Property Additions	\$ 2,755	\$ 7	\$ -	\$ 2	\$ -	\$ 2,764

	<u>Nonutility Operations</u>					
	<u>Utility Operations</u>	<u>MEMCO Operations</u>	<u>Generation and Marketing</u>	<u>All Other (a)</u>	<u>Reconciling Adjustments (b)</u>	<u>Consolidated</u>
	(in millions)					
<u>December 31, 2007</u>						
Total Property, Plant and Equipment	\$ 45,514	\$ 263	\$ 567	\$ 38	\$ (237)	\$ 46,145
Accumulated Depreciation and Amortization	<u>16,107</u>	<u>61</u>	<u>112</u>	<u>7</u>	<u>(12)</u>	<u>16,275</u>
Total Property, Plant and Equipment – Net	<u><u>\$ 29,407</u></u>	<u><u>\$ 202</u></u>	<u><u>\$ 455</u></u>	<u><u>\$ 31</u></u>	<u><u>\$ (225)</u></u>	<u><u>\$ 29,870</u></u>
Total Assets	\$ 39,322	\$ 340	\$ 702	\$ 12,135	\$ (12,133)(d)	\$ 40,366
Investments in Equity Method Subsidiaries	14	2	-	-	-	16

	<u>Nonutility Operations</u>						
	<u>Utility Operations</u>	<u>MEMCO Operations</u>	<u>Generation and Marketing</u>	<u>All Other (a)</u>		<u>Reconciling Adjustments</u>	<u>Consolidated</u>
<u>December 31, 2006</u>				(in millions)			
Total Property, Plant and Equipment	\$ 41,420	\$ 239	\$ 327	\$ 35	\$ -	\$ 42,021	
Accumulated Depreciation and Amortization	15,101	51	83	5	-	15,240	
Total Property, Plant and Equipment – Net	<u>\$ 26,319</u>	<u>\$ 188</u>	<u>\$ 244</u>	<u>\$ 30</u>	<u>\$ -</u>	<u>\$ 26,781</u>	
Total Assets	\$ 36,632	\$ 315	\$ 342	\$ 11,460	\$ (10,762)(d)	\$ 37,987	
Assets Held for Sale	44	-	-	-	-	44	
Investments in Equity Method Subsidiaries	-	-	42	-	-	42	

- (a) All Other includes:
- Parent company's guarantee revenue received from affiliates, interest income and interest expense and other nonallocated costs.
 - Tax and interest expense adjustments related to our UK operations and SEEBOARD, which were not eligible for discontinued operations treatment and were sold in 2004 and 2002, respectively.
 - Our gas pipeline and storage operations, which were sold in 2004 and 2005.
 - Other energy supply related businesses, including the Plaquemine Cogeneration Facility, which was sold in 2006. See "Plaquemine Cogeneration Facility" section of Note 8.
- (b) Includes eliminations due to an intercompany capital lease which began in the first quarter of 2007.
- (c) Gross Property Additions for All Other includes construction expenditures of \$4 million and \$25 million in 2007 and 2006, respectively, related to the acquisition of turbines by one of our nonregulated, wholly-owned subsidiaries. These turbines will be refurbished and transferred to a generating facility within our Utility Operations segment by the second half of 2008.
- (d) 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 in subsidiary companies.
- (e) PSO and SWEPco transferred certain existing ERCOT energy marketing contracts to AEPEP (Generation and Marketing segment) and entered into intercompany financial and physical purchase and sales agreements with AEPEP. As a result, we reported \$347 million of third-party purchases for these energy marketing contracts as a reduction of Revenues from External Customers which is offset by the related sales to AEPEP in Revenues from Other Operating Segments of \$366 million.

12. DERIVATIVES, HEDGING AND FINANCIAL INSTRUMENTS

DERIVATIVES AND HEDGING

SFAS 133 requires recognition of all qualifying derivative instruments as either assets or liabilities in the statement of financial position at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes and supply and demand market data and assumptions. The fair values determined are reduced by the appropriate valuation adjustments for items such as discounting, liquidity and credit quality. Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to be less than or more than what the price should be based purely on supply and demand. Because energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value open long-term risk management contracts. Unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and at the time a contract settles. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices are not consistent with our approach at estimating current market consensus for forward prices in the current period. This is particularly true for long-term contracts.

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in SFAS 133. Derivative contracts that have been designated as normal purchases or normal sales under SFAS 133 are not subject to MTM accounting treatment and are recognized in the Consolidated Statements of Income on an accrual basis.

Our accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on

the exposure, we designate a hedging instrument as a fair value hedge or a cash flow hedge. For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof that is attributable to a particular risk), we recognize the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item associated with the hedged risk in earnings during the period of change. For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), we initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheets until the period the hedged item affects earnings. We recognize any hedge ineffectiveness in earnings immediately during the period of change, except in regulated jurisdictions where hedge ineffectiveness is recorded as a regulatory asset (for losses) or a regulatory liability (for gains).

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in Revenues on a net basis in the Consolidated Statements of Income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in Revenues or Expenses on the Consolidated Statements of Income depending on the relevant facts and circumstances.

Fair Value Hedging Strategies

At certain times, we enter into interest rate derivative transactions in order to manage existing fixed interest rate risk exposure. These interest rate derivative transactions effectively modify our exposure to interest rate risk by converting a portion of our fixed-rate debt to a floating rate. We record gains or losses on swaps that qualify for fair value hedge accounting treatment, as well as offsetting changes in the fair value of the debt being hedged, in Interest Expense on our Consolidated Statements of Income. During 2007, 2006 and 2005, we recognized no hedge ineffectiveness related to these derivative transactions.

Cash Flow Hedging Strategies

We enter into, and designate as cash flow hedges, certain derivative transactions for the purchase and sale of electricity, coal and natural gas (collectively “Power”) in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. We closely monitor the potential impacts of commodity price changes and, where appropriate, enter into derivative transactions to protect margins for a portion of future electricity sales and fuel purchases. Realized gains and losses on these derivatives designated as cash flow hedges are included in Revenues or Fuel and Other Consumables Used for Electric Generation on our Consolidated Statements of Income, depending on the specific nature of the risk being hedged. We do not hedge all variable price risk exposure related to energy commodities. During 2007, 2006 and 2005, we recognized immaterial amounts in earnings related to hedge ineffectiveness.

We enter into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify our exposure to interest rate risk by converting a portion of our floating-rate debt to a fixed rate. We also enter into interest rate derivative contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. Our anticipated fixed-rate debt offerings have a high probability of occurrence because the proceeds will be used to fund existing debt maturities as well as fund projected capital expenditures. We reclassify gains and losses on the hedges from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During 2007, 2006 and 2005, we recognized immaterial amounts in earnings related to hedge ineffectiveness.

At times we are exposed to foreign currency exchange rate risks primarily because we purchase certain fixed assets from foreign suppliers. In accordance with our risk management policy, we may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency’s appreciation against the dollar. The accumulated gains or losses related to our foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheets into Other Operation and Maintenance Expenses on our Consolidated Statements of Income over the same period as the depreciable lives of the fixed assets that were designated as the hedged items in qualifying foreign currency hedging relationships. We do not hedge all foreign currency exposure. During 2007, 2006 and 2005, we recognized no hedge ineffectiveness related to these derivative transactions.

We entered into natural gas futures contracts to protect against the reduction in value of forecasted cash flows resulting from spot purchases and sales of natural gas at Houston Ship Channel (HSC). Realized gains and losses on these derivatives designated as cash flow hedges are included in Revenues. As a result of the sale of HPL in 2005, we no longer employ this risk management strategy. During 2005, we recognized immaterial amounts in earnings related to hedge ineffectiveness.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheet at December 31, 2007 are:

	<u>Hedging Assets (a)</u>	<u>Hedging Liabilities (a)</u>	<u>Accumulated Other Comprehensive Income (Loss) After Tax</u>	<u>Portion Expected to be Reclassified to Earnings During the Next Twelve Months</u>
	(in millions)			
Power	\$ 9	\$ (10)	\$ (1)	\$ (2)
Interest Rate	-	(3)	(25)	(3)
Total	<u>\$ 9</u>	<u>\$ (13)</u>	<u>\$ (26)</u>	<u>\$ (5)</u>

- (a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on our Consolidated Balance Sheet.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheet at December 31, 2006 are:

	<u>Hedging Assets (a)</u>	<u>Hedging Liabilities (a)</u>	<u>Accumulated Other Comprehensive Income (Loss) After Tax</u>	<u>Portion Expected to be Reclassified to Earnings During the Next Twelve Months</u>
	(in millions)			
Power	\$ 30	\$ (4)	\$ 17	\$ 17
Interest Rate	4	(4)	(23) (b)	(2)
Total	<u>\$ 34</u>	<u>\$ (8)</u>	<u>\$ (6)</u>	<u>\$ 15</u>

- (a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on our Consolidated Balance Sheet.
- (b) Includes \$1 million loss recorded in an equity investment.

The actual amounts that we reclassify from Accumulated Other Comprehensive Income (Loss) to Net Income can differ due to market price changes. As of December 31, 2007, the maximum length of time that we are hedging, with SFAS 133 designated contracts, our exposure to variability in future cash flows related to forecasted transactions is 30 months.

The following table represents the activity in Accumulated Other Comprehensive Income (Loss) for derivative contracts that qualify as cash flow hedges at December 31, 2007:

	<u>Amount</u> <u>(in millions)</u>
Balance at December 31, 2004	\$ -
Changes in fair value	(5)
Reclasses from AOCI to net earnings	(22)
Balance at December 31, 2005	(27)
Changes in fair value	13
Reclasses from AOCI to net earnings	8
Balance at December 31, 2006	(6)
Changes in fair value	(5)
Reclasses from AOCI to net earnings	(15)
Balance at December 31, 2007	<u>\$ (26)</u>

FINANCIAL INSTRUMENTS

The fair value of Long-term Debt is based on quoted market prices for the same or similar issues and the current dividend or interest rates offered for instruments with similar maturities. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that we could realize in a current market exchange.

The book values and fair values of significant financial instruments at December 31, 2007 and 2006 are summarized in the following tables.

	December 31,			
	2007		2006	
	<u>Book Value</u>	<u>Fair Value</u>	<u>Book Value</u>	<u>Fair Value</u>
	(in millions)			
Long-term Debt	\$ 14,994	\$ 14,917	\$ 13,698	\$ 13,743

13. INCOME TAXES

The details of our consolidated income taxes before discontinued operations, extraordinary loss and cumulative effect of accounting change as reported are as follows:

	Years Ended December 31,		
	<u>2007</u>	<u>2006</u>	<u>2005</u>
	(in millions)		
Federal:			
Current	\$ 464	\$ 429	\$ 375
Deferred	35	5	28
Total	<u>499</u>	<u>434</u>	<u>403</u>
State and Local:			
Current	1	61	25
Deferred	16	(10)	4
Total	<u>17</u>	<u>51</u>	<u>29</u>
International:			
Current	-	-	(2)
Deferred	-	-	-
Total	<u>-</u>	<u>-</u>	<u>(2)</u>
Total Income Tax Expense Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	<u>\$ 516</u>	<u>\$ 485</u>	<u>\$ 430</u>

The following is a reconciliation of our consolidated difference between the amount of federal income taxes computed by multiplying book income before income taxes by the federal statutory tax rate and the amount of income taxes reported.

	Years Ended December 31,		
	2007	2006	2005
	(in millions)		
Net Income	\$ 1,089	\$ 1,002	\$ 814
Discontinued Operations (Net of Income Tax of \$(18) Million, \$(1) Million and \$(30) Million in 2007, 2006 and 2005, respectively)	(24)	(10)	(27)
Extraordinary Loss, (Net of Income Tax of \$(39) Million and \$(121) Million in 2007 and 2005, respectively)	79	-	225
Cumulative Effect of Accounting Change (Net of Income Tax of \$(9) Million in 2005)	-	-	17
Preferred Stock Dividends	3	3	7
Income Before Preferred Stock Dividends of Subsidiaries	1,147	995	1,036
Income Tax Expense Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	516	485	430
Pretax Income	<u>\$ 1,663</u>	<u>\$ 1,480</u>	<u>\$ 1,466</u>
Income Taxes on Pretax Income at Statutory Rate (35%)	\$ 582	\$ 518	\$ 513
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	29	38	39
Investment Tax Credits, Net	(24)	(29)	(32)
Tax Effects of International Operations	-	-	(2)
Energy Production Credits	(18)	(19)	(18)
State Income Taxes	11	33	19
Removal Costs	(21)	(15)	(14)
AFUDC	(18)	(18)	(14)
Medicare Subsidy	(12)	(12)	(13)
Tax Reserve Adjustments	(8)	9	(11)
Other	(5)	(20)	(37)
Total Income Tax Expense Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	<u>\$ 516</u>	<u>\$ 485</u>	<u>\$ 430</u>
Effective Income Tax Rate	<u>31.0%</u>	<u>32.8%</u>	<u>29.3%</u>

The following table shows elements of the net deferred tax liability and significant temporary differences:

	December 31,	
	2007	2006
	(in millions)	
Deferred Tax Assets	\$ 2,284	\$ 2,384
Deferred Tax Liabilities	(7,023)	(7,074)
Net Deferred Tax Liabilities	<u>\$ (4,739)</u>	<u>\$ (4,690)</u>
Property-Related Temporary Differences	\$ (3,300)	\$ (3,292)
Amounts Due from Customers for Future Federal Income Taxes	(202)	(193)
Deferred State Income Taxes	(324)	(318)
Transition Regulatory Assets	(3)	(46)
Securitized Transition Assets	(806)	(809)
Regulatory Assets	(225)	(334)
Accrued Pensions	(211)	(155)
Deferred Income Taxes on Other Comprehensive Loss	83	120
Accrued Nuclear Decommissioning	(286)	(247)
All Other, Net	535	584
Net Deferred Tax Liabilities	<u>\$ (4,739)</u>	<u>\$ (4,690)</u>

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

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

We, along with our subsidiaries, file income tax returns in various state, local, and foreign jurisdictions. These taxing authorities routinely examine our tax returns and we are currently under examination in several state and local jurisdictions. We believe that we have filed tax returns with positions that may be challenged by these tax authorities. However, management does not believe that the ultimate resolution of these audits will materially impact results of operations. With few exceptions, we are no longer subject to state, local or non-U.S. income tax examinations by tax authorities for years before 2000.

Prior to the adoption of FIN 48, we recorded interest and penalty expense related to uncertain tax positions in tax expense accounts. With the adoption of FIN 48, we began recognizing interest accruals related to uncertain tax positions in interest income or expense as applicable, and penalties in Other Operation and Maintenance. In 2007 we reported \$2 million of interest expense, \$5 million of interest income and reversed \$17 million of prior period interest expense. The Company had approximately \$16 and \$66 million for the payment of interest and penalties accrued at December 31, 2007 and 2006, respectively.

As a result of the implementation of FIN 48 on January 1, 2007, we recognized a \$17 million increase in the liabilities for unrecognized tax benefits, as well as related interest expense and penalties, which was accounted for as a reduction to the January 1, 2007 balance of retained earnings.

As of December 31, 2007, the reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	(in millions)
Balance at January 1, 2007	\$ 175
Increase - Tax Positions Taken During a Prior Period	75
Decrease - Tax Positions Taken During a Prior Period	(43)
Increase - Tax Positions Taken During the Current Year	20
Increase - Settlements with Taxing Authorities	2
Decrease - Lapse of the Applicable Statute of Limitations	(7)
Balance at December 31, 2007	<u>\$ 222</u>

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is \$147 million. We believe there will be no significant net increase or decrease in unrecognized tax benefits within 12 months of the reporting date.

Federal Tax Legislation

In 2005, the Energy Tax Incentives Act of 2005 was signed into law. This act created a limited amount of tax credits for the building of IGCC plants. The credit is 20% of the eligible property in the construction of new plant or 20% of the total cost of repowering of an existing plant using IGCC technology. In the case of a newly constructed IGCC plant, eligible property is defined as the components necessary for the gasification of coal, including any coal handling and gas separation equipment. We announced plans to construct two new IGCC plants that may be eligible for the allocation of these credits. We filed applications for the Mountaineer and Great Bend projects with the DOE and the IRS. Both projects were certified by the DOE and qualified by the IRS. However, neither project was awarded credits during this round of credit awards. We will continue to pursue credits for the next round of available credits.

The Tax Increase Prevention and Reconciliation Act of 2005 (TIPRA 2005) was passed May 17, 2006. The majority of the provisions in TIPRA 2005 were directed toward individual income tax relief including the extension of reduced tax rates for dividends and capital gains through 2010. We believe the application of this act will not materially affect our results of operations, cash flows, or financial condition.

The President signed the Pension Protection Act of 2006 (PPA 2006) into law on August 17, 2006. This law is directed toward strengthening qualified retirement plans and adding new restrictions on charitable contributions. Specifically, PPA 2006 concentrates on the funding of defined benefit plans and the health of the Pension Benefit Guaranty Corporation. PPA 2006 imposes new minimum funding rules for multiemployer plans as well as increasing the deduction limitation for contributions to multiemployer defined benefit plans. Due to the significant funding of the AEP pension plans in 2005, the Act will not materially affect our results of operations, cash flows, or financial condition.

On December 20, 2006, the Tax Relief and Health Care Act of 2006 (TRHCA 2006) was signed into law. The primary purpose of the bill was to extend expiring tax provisions for individuals and business taxpayers and provide increased tax flexibility around medical benefits. In addition to extending the lower capital gains and dividend tax rates for individuals, TRHCA 2006 extended the research credit and for 2007 provided a new alternative formula for determining the research credit. The application of TRHCA 2006 is not expected to materially affect our results of operations, cash flows, or financial condition.

Several tax bills and other legislation with tax-related sections were enacted in 2007, including the Tax Technical Corrections Act of 2007, the Tax Increase Prevention Act of 2007 and the Energy Independence and Security Act of 2007. The tax law changes enacted in 2007 are not expected to materially affect our results of operations, cash flows, or financial condition.

State Tax Legislation

On June 30, 2005, the Governor of Ohio signed Ohio House Bill 66 into law enacting sweeping tax changes impacting all companies doing business in Ohio. Most of the significant tax changes phase in over a five-year period, while some of the less significant changes became fully effective July 1, 2005. Changes to the Ohio franchise tax, nonutility property taxes, and the new commercial activity tax are subject to phase-in. The Ohio franchise tax will fully phase-out over a five-year period beginning with a 20% reduction in state franchise tax for taxable income accrued during 2005. In 2005, we reversed deferred state income tax liabilities of \$83 million that are not expected to reverse during the phase-out. We recorded \$4 million as a reduction to Income Tax Expense and, for the Ohio companies, established a regulatory liability for \$57 million pending rate-making treatment in Ohio. See "Ormet" section of Note 4 for further discussion. For those companies in which state income taxes flow through for rate-making purposes, the adjustments reduced the regulatory assets associated with the deferred state income tax liabilities by \$22 million. In November 2006, the PUCO ordered that the \$57 million be amortized to income as an offset to power supply contract losses incurred by CSPCo and OPCo for sales to Ormet.

The new legislation also imposes a new commercial activity tax at a fully phased-in rate of 0.26% on all Ohio gross receipts. The new tax is being phased-in over a five-year period that began July 1, 2005 at 23% of the full 0.26% rate. As a result of this new tax, expenses of approximately \$6 million, \$4 million and \$2 million were recorded in 2007, 2006 and 2005, respectively, in Taxes Other than 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. 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 our Consolidated Balance Sheet of \$48 million of which \$2 million was credited to Income Tax Expense and \$46 million was credited to Regulatory Assets based upon the related rate-making treatment.

On July 12, 2007, the Governor of Michigan signed Michigan Senate Bill 0094 (MBT Act) and related companion bills into law providing a comprehensive restructuring of Michigan's principal business tax. The new law is effective January 1, 2008 and replaces the Michigan Single Business Tax that expired at the end of 2007. The MBT Act is composed of a new tax which will be calculated based upon two components: (a) a business income tax (BIT) imposed at a rate of 4.95% and (b) a modified gross receipts tax (GRT) imposed at a rate of 0.80%, which will collectively be referred to as the BIT/GRT tax calculation. The new law also includes significant credits for engaging in Michigan-based activity.

On September 30, 2007, the Governor of Michigan signed House Bill 5198 which amends the MBT Act to provide for a new deduction on the BIT and GRT tax returns equal to the book-tax basis differences triggered as a result of the enactment of the MBT Act. This new state-only temporary difference will be deducted over a 15-year period on the MBT Act tax returns starting in 2015. The purpose of the new MBT Act state deduction was to provide companies relief from the recordation of the SFAS 109 Income Tax Liability. We have evaluated the impact of the MBT Act and the application of the MBT Act will not materially affect our results of operations, cash flows, or financial condition.

14. LEASES

Leases of property, plant and equipment are for periods up to 60 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Capital leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

	Years Ended December 31,		
	2007	2006	2005
Lease Rental Costs		(in millions)	
Net Lease Expense on Operating Leases	\$ 364	\$ 340	\$ 298
Amortization of Capital Leases	68	64	57
Interest on Capital Leases	20	17	13
Total Lease Rental Costs	\$ 452	\$ 421	\$ 368

The following table shows the property, plant and equipment under capital leases and related obligations recorded on our Consolidated Balance Sheets. Capital lease obligations are included in Current Liabilities – Other and Noncurrent Liabilities – Deferred Credits and Other on our Consolidated Balance Sheets.

	December 31,	
	2007	2006
	(in millions)	
Property, Plant and Equipment Under Capital Leases		
Production	\$ 89	\$ 94
Distribution	15	15
Other	458	360
Construction Work in Progress	39	30
Total Property, Plant and Equipment Under Capital Leases	601	499
Accumulated Amortization	232	210
Net Property, Plant and Equipment Under Capital Leases	\$ 369	\$ 289
Obligations Under Capital Leases		
Noncurrent Liability	\$ 267	\$ 210
Liability Due Within One Year	104	81
Total Obligations Under Capital Leases	\$ 371	\$ 291

Future minimum lease payments consisted of the following at December 31, 2007:

	Capital Leases	Noncancelable Operating Leases
Future Minimum Lease Payments	(in millions)	
2008	\$ 117	\$ 337
2009	90	311
2010	59	283
2011	30	250
2012	25	230
Later Years	149	1,775
Total Future Minimum Lease Payments	\$ 470	\$ 3,186
Less Estimated Interest Element	99	
Estimated Present Value of Future Minimum Lease Payments	\$ 371	

Rockport Lease

AEGCo and I&M entered into a sale-and-leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated, unconsolidated trustee for Rockport Plant Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. Neither AEGCo, I&M nor AEP has an ownership interest in the Owner Trustee and do not guarantee its debt. The future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2007 are as follows:

	AEGCo	I&M
Future Minimum Lease Payments	(in millions)	
2008	\$ 74	\$ 74
2009	74	74
2010	74	74
2011	74	74
2012	74	74
Later Years	738	738
Total Future Minimum Lease Payments	\$ 1,108	\$ 1,108

Railcar Lease

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, 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. This operating lease agreement allows us to avoid a large initial capital expenditure and to spread our railcar costs evenly over the expected twenty-year usage.

Under the return-and-sale option, the lessor is guaranteed that the sale proceeds will equal at least a specified lessee obligation amount which declines with each five-year renewal. At December 31, 2007, the maximum potential loss was approximately \$30 million (\$20 million, net of tax) assuming the fair market value of the equipment is zero at the end of the current lease term. However, we believe that the fair market value would produce a sufficient sales price to avoid any loss.

In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignment is accounted for as new operating leases for I&M and SWEPCo. The future minimum lease obligation of \$46 million as of December 31, 2007 is included in our future minimum lease payments schedule earlier in this note. I&M and SWEPCo intend to renew these leases for the full twenty years and have assumed the guarantee under the return-and-sale option.

We have other railcar lease arrangements that do not utilize this type of financing structure.

Sabine Dragline Lease

In December 2006, Sabine Mining Company (Sabine), an entity consolidated under FIN 46, entered into a capital lease agreement with a nonaffiliated company to finance the purchase of a \$51 million electric dragline for Sabine's mining operations. In 2006, the initial capital outlay for the dragline was \$26 million. Sabine incurred an additional \$13 million of transportation, assembly and upgrade costs in 2007. Sabine expects to incur an additional \$12 million of setup costs prior to the estimated completion date of mid-2008. These additional costs will be added to SWEPCo's consolidated capital lease assets and capital lease obligations as they are incurred. For the year ended December 31, 2007, Sabine paid \$2 million of interim rent. Sabine will continue to pay interim rent on a quarterly basis through the estimated completion date of mid-2008. Once the dragline is fully assembled, Sabine will pay capital and interest payments on the outstanding lease obligation. The capital lease asset is included in Construction Work in Progress and the capital lease obligation is included in Noncurrent Liabilities – Deferred Credits and Other on our December 31, 2007 and 2006 Consolidated Balance Sheets. Total future payments of \$60 million were calculated using both interim rent prior to completion and capital and interest from completion until the maturity of the lease using the current capital outlay of \$39 million. These future payment obligations are included in our future minimum lease payments schedule earlier in this note.

I&M Nuclear Fuel Lease

In December 2007, I&M entered into a sale-and-leaseback transaction with Citicorp Leasing, Inc. (CLI), an unrelated, unconsolidated, wholly-owned subsidiary of Citibank, N.A. to lease nuclear fuel for I&M's Cook Plant. I&M sold a portion of its unamortized nuclear fuel inventory to CLI at cost for \$85 million. The lease has a variable rate based on one month LIBOR and is accounted for as a capital lease with lease terms up to 60 months. The future payment obligations of \$94 million are included in our future minimum lease payments schedule earlier in this note. At December 31, 2007, the net capital lease asset is included in Property, Plant and Equipment – Other and the long-term and short-term capital lease obligations are included in Noncurrent Liabilities – Deferred Credits and Other and Current Liabilities – Other, respectively, on our December 31, 2007 Consolidated Balance Sheet. The future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2007 are as follows, based on estimated fuel burn:

Future Minimum Lease Payments	(in millions)
2008	\$ 37
2009	28
2010	19
2011	6
2012	4
Total Future Minimum Lease Payments	\$ 94

15. FINANCING ACTIVITIES

Common Stock

Common Stock Repurchase

In February 2005, our Board of Directors authorized the repurchase of up to \$500 million of our common stock from time to time through 2006. In March 2005, we purchased 12.5 million shares of our outstanding common stock through an accelerated share repurchase agreement at an initial price of \$34.63 per share plus transaction fees. The purchase of shares in the open market was completed by a broker-dealer in May 2005 and we received a purchase price adjustment of \$6.45 million based on the actual cost of the shares repurchased. Based on this adjustment, our actual stock purchase price averaged \$34.18 per share. Management has not established a timeline for the buyback of the remaining stock under this plan.

Equity Units and Remarketing of Senior Notes

In June 2002, AEP issued 6.9 million equity units at \$50 per unit and received proceeds of \$345 million. Each equity unit consisted of a forward purchase contract and a senior note. In June 2005, we remarketed and settled \$345 million of our 5.75% senior notes at a new interest rate of 4.709%. The senior notes matured on August 16, 2007. We did not receive any proceeds from the mandatory remarketing.

Issuance of Common Stock

On August 16, 2005, we issued approximately 8.4 million shares of common stock in connection with the settlement of forward purchase contracts that formed a part of our outstanding 9.25% equity units. In exchange for \$50 per equity unit, holders of the equity units received 1.2225 shares of AEP common stock for each purchase contract and cash in lieu of fractional shares. Each holder was not required to make any additional cash payment. The equity unit holder's purchase obligation was satisfied from the proceeds of a portfolio of U.S. Treasury securities held in a collateral account that matured on August 1, 2005. The portfolio of U.S. Treasury securities was acquired in connection with the June 2005 remarketing of the senior notes discussed above.

We issued 2.4 million, 2.3 million and 1.9 million shares of common stock in connection with our stock option plan during 2007, 2006 and 2005, respectively.

Set forth below is a reconciliation of common stock share activity for the years ended December 31, 2007, 2006 and 2005:

Shares of Common Stock	Issued	Held in Treasury
Balance, January 1, 2005	404,858,145	8,999,992
Issued	10,360,685	-
Treasury Stock Acquisition	-	12,500,000
Balance, December 31, 2005	415,218,830	21,499,992
Issued	2,955,898	-
Balance, December 31, 2006	418,174,728	21,499,992
Issued	3,751,968	-
Balance, December 31, 2007	421,926,696	21,499,992

Preferred Stock

Information about the components of preferred stock of our subsidiaries is as follows:

	Call Price Per Share (a)	December 31, 2007		Amount (in millions)
		Shares Authorized (b)	Shares Outstanding (c)	
Not Subject to Mandatory Redemption: 4.00% - 5.00%	\$102-\$110	1,525,903	606,878	\$ 61

	Call Price Per Share (a)	December 31, 2006		Amount (in millions)
		Shares Authorized (b)	Shares Outstanding (c)	
Not Subject to Mandatory Redemption: 4.00% - 5.00%	\$102-\$110	1,525,903	607,044	\$ 61

- At the option of the subsidiary, the shares may be redeemed at the call price plus accrued dividends. The involuntary liquidation preference is \$100 per share for all outstanding shares.
- As of December 31, 2007, our subsidiaries had 14,488,045 shares of \$100 par value preferred stock, 22,200,000 shares of \$25 par value preferred stock and 7,822,480 shares of no par value preferred stock that were authorized but unissued. As of December 31, 2006, our subsidiaries had 14,487,993 shares of \$100 par value preferred stock, 22,200,000 shares of \$25 par value preferred stock and 7,822,366 shares of no par value preferred stock that were authorized but unissued.
- The number of shares of preferred stock redeemed is 166 shares in 2007, 598 shares in 2006 and 664,470 shares in 2005.

Long-term Debt

Type of Debt and Maturity	Weighted Average Interest Rate December 31, 2007	Interest Rate Range at December 31,		December 31,	
	2007	2007	2006	2007	2006
(in millions)					
SENIOR UNSECURED NOTES (a)					
2007-2011	5.24%	3.60%-6.60%	3.60%-6.91%	\$ 2,494	\$ 3,085
2012-2018	5.52%	4.85%-6.375%	4.85%-6.375%	3,918	2,793
2032-2037	6.27%	5.625%-6.70%	5.625%-6.65%	3,493	2,775
POLLUTION CONTROL BONDS (b)					
2007-2011	4.30%	4.15%-4.50%	3.60%-4.90%	131	181
2014-2024	4.67%	3.70%-6.05%	3.50%-6.05%	811	811
2025-2042	4.72%	3.80%-6.00%	3.53%-6.125%	1,248	958
NOTES PAYABLE (c)					
2008-2024	6.91%	4.47%-9.60%	4.47%-9.60%	311	337
SECURITIZATION BONDS (d)					
2008-2020	5.33%	4.98%-6.25%	4.98%-6.25%	2,257	2,335
FIRST MORTGAGE BONDS (e) (f)					
2008	7.125%	7.125%	7.00%-7.75%	19	117
NOTES PAYABLE TO TRUST					
2043	5.25%	5.25%	5.25%	113	113
SPENT NUCLEAR FUEL OBLIGATION (g)				259	247
OTHER LONG-TERM DEBT (h)					
2026	13.718%	13.718%	13.718%	2	2
Unamortized Discount (net)				(62)	(56)
Total Long-term Debt Outstanding				14,994	13,698
Less Portion Due Within One Year				792	1,269
Long-term Portion				<u>\$ 14,202</u>	<u>\$ 12,429</u>

- (a) Certain senior unsecured notes have been adjusted for MTM of Fair Value Hedges associated with the debt.
- (b) For certain series of pollution control bonds, interest rates are subject to periodic adjustment. Certain series will be purchased on demand at periodic interest adjustment dates. Letters of credit from banks, standby bond purchase agreements and insurance policies support certain series.
- (c) Notes payable represent outstanding promissory notes issued under term loan agreements and revolving credit agreements with a number of banks and other financial institutions. At expiration, all notes then issued and outstanding are due and payable. Interest rates are both fixed and variable. Variable rates generally relate to specified short-term interest rates.
- (d) In October 2006, AEP Texas Central Transition Funding II LLC (TFII), a subsidiary of TCC, issued \$1.7 billion in securitization bonds with interest rates ranging from 4.98% to 5.3063% and final maturity dates ranging from January 2012 to July 2021. Scheduled final payment dates range from January 2010 to July 2020. TFII is the sole owner of the transition charges and the original transition property. The holders of the securitization bonds do not have recourse to any assets or revenues of TCC. The creditors of TCC do not have recourse to any assets or revenues of TFII, including, without limitation, the original transition property.
- (e) There are certain limitations on establishing additional liens against our assets under our indentures.
- (f) In May 2004, cash and treasury securities were deposited with a trustee to defease all of TCC's outstanding First Mortgage Bonds. The defeased TCC First Mortgage Bonds had a balance of \$19 million in 2007 and 2006. The defeased TCC First Mortgage Bonds were retired in February 2008. Trust fund assets related to this obligation of \$22 and \$2 million are included in Other Temporary Investments on our Consolidated Balance Sheets at December 31, 2007 and 2006, respectively, and \$21 million is included in Deferred Charges and Other on our Consolidated Balance Sheets at December 31, 2006. In December 2005, cash and treasury securities were deposited with a trustee to defease the remaining TNC outstanding First Mortgage Bond. The defeased TNC First Mortgage Bond was retired in June 2007. The defeased TNC First Mortgage Bond had a balance of \$8 million at December 31, 2006. Trust fund assets related to this obligation of \$9 million are included in Other Temporary Investments on our Consolidated Balance Sheets at December 31, 2006. Trust fund assets are restricted for exclusive use in funding the interest and principal due on the First Mortgage Bonds.
- (g) Spent Nuclear Fuel Obligation consists of a liability along with accrued interest for disposal of spent nuclear fuel (see Note 10).
- (h) Other long-term debt consists of a financing obligation under a sale and leaseback agreement.

LONG-TERM DEBT OUTSTANDING AT DECEMBER 31, 2007 IS PAYABLE AS FOLLOWS:

	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>	<u>2012</u>	<u>After</u>	<u>Total</u>
				(in millions)		2012	
Principal Amount	\$ 792	\$ 447	\$ 1,722	\$ 604	\$ 557	\$ 10,934	\$ 15,056
Unamortized Discount							(62)
Total Long-term Debt Outstanding at December 31, 2007							<u><u>\$ 14,994</u></u>

In January 2008, TCC retired \$74 million of its outstanding Securitization Bonds.

In February 2008, CSPCo retired \$52 million of 6.51% Senior Unsecured Notes at maturity.

In February 2008, TCC retired \$19 million of 7.125% First Mortgage Bonds at maturity.

As of December 31, 2007, we have \$1.5 billion of tax-exempt long-term debt (Pollution Control Bonds) sold at auction rates that are reset every 7, 28 or 35 days and are insured by bond insurers previously AAA-rated, namely Ambac Assurance Corporation, Financial Guaranty Insurance Co., MBIA Insurance Corporation and XL Capital Assurance Inc. Due to the exposure that these bond insurers have in connection with recent developments in the subprime credit market, the credit ratings of these insurers have been downgraded or placed on negative outlook. This has contributed to higher interest rates in successful auctions and increasing occurrences of failed auctions, including a number of auctions of our tax-exempt long-term debt. The instruments under which the bonds are issued allow us to convert to other short-term variable-rate structures, term-put structures and fixed-rate structures. We are planning to reduce our outstanding auction rate market securities by redeeming, refunding or converting such debt securities to other permitted modes, including term-put and fixed-rate structures. We expect this to result in additional transaction costs and higher interest charges for this tax-exempt long-term debt.

In February 2008, we notified the trustee that we plan to retire \$45 million of pollution control bonds and to redeem an additional \$50 million of pollution control bonds for possible future remarketing. Also, in early March 2008 we expect to notify the trustee that we plan to redeem \$40 million of pollution control bonds for possible future remarketing. We have classified these pollution control bonds as Long-term Debt Due Within One Year on the December 31, 2007 Consolidated Balance Sheet.

Dividend Restrictions

Under the Federal Power Act, AEP's public utility subsidiaries are restricted from paying dividends out of stated capital.

Trust Preferred Securities

SWEPCo has a wholly-owned business trust that issued trust preferred securities. Effective July 1, 2003, the trust was deconsolidated due to the implementation of FIN 46. The SWEPCo trust, which holds mandatorily redeemable trust preferred securities, is reported as two components on our Consolidated Balance Sheets. The investment in the trust, which was \$3 million as of December 31, 2007 and 2006, is included in Deferred Charges and Other within Other Noncurrent Assets. The Junior Subordinated Debentures, in the amount of \$113 million as of December 31, 2007 and 2006, are reported as Notes Payable to Trust within Long-term Debt.

The business trust is treated as a nonconsolidated subsidiary of SWEPCo. The only asset of the business trust is the subordinated debentures issued by SWEPCo as specified above. In addition to the obligations under the subordinated debentures, SWEPCo also agreed to a security obligation, which represents a full and unconditional guarantee of its capital trust obligation.

Lines of Credit and Short-term Debt – AEP System

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 December 31, 2007, we had credit facilities totaling \$3 billion to support our commercial paper program. As of December 31, 2007, AEP's commercial paper outstanding related to the corporate borrowing program was \$659 million. For the corporate borrowing program the maximum amount of commercial paper outstanding during 2007 was \$865 million and the weighted average interest rate of commercial paper outstanding during the year was 5.54%. Our outstanding short-term debt was as follows:

Type of Debt	December 31,			
	2007		2006	
	Outstanding Amount	Interest Rate (a)	Outstanding Amount	Interest Rate (a)
	(in thousands)		(in thousands)	
Commercial Paper – AEP	\$ 659,135	5.54 %	\$ -	-
Commercial Paper – JMG (b)	701	5.35 %	1,203	5.56 %
Line of Credit – Sabine (c)	285	5.25 %	17,143	6.38 %
Total	\$ 660,121		\$ 18,346	

- (a) Weighted average rate.
- (b) This commercial paper is specifically associated with the Gavin Scrubber and is backed by a separate credit facility. This commercial paper does not reduce available liquidity under AEP's credit facilities.
- (c) Sabine is consolidated under FIN 46. This line of credit does not reduce available liquidity under AEP's credit facilities.

Sale of Receivables – AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires from affiliated utility subsidiaries to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," allowing the receivables to be taken off of AEP Credit's balance sheet and allowing AEP Credit to repay any debt obligations. We have no ownership interest in the commercial paper conduits and are not required to consolidate these entities in accordance with GAAP. AEP Credit continues to service the receivables. We entered into this off-balance sheet transaction to allow AEP Credit to repay its outstanding debt obligations, continue to purchase our operating companies' receivables, and accelerate AEP Credit's cash collections.

In October 2007, we renewed AEP Credit's sale of receivables agreement. The sale of receivables agreement provides a commitment of \$650 million from banks and commercial paper conduits to purchase receivables from AEP Credit. Under the agreement, the commitment will increase to \$700 million for the months of August and September to accommodate seasonal demand. This agreement will expire in October 2008. We intend to extend or replace the sale of receivables agreement. The previous sale of receivables agreement, which expired in August 2007 and was extended until October 2007, provided a commitment of \$600 million from a bank conduit to purchase receivables from AEP Credit. At December 31, 2007, \$507 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts.

AEP Credit purchases accounts receivable through purchase agreements with CSPCo, I&M, KGPCo, KPCo, OPCo, PSO, SWEP Co and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in all of its regulatory jurisdictions, only a portion of APCo's accounts receivable are sold to AEP Credit.

Comparative accounts receivable information for AEP Credit is as follows:

	Years Ended December 31,		
	2007	2006	2005
	(\$ in millions)		
Proceeds from Sale of Accounts Receivable	\$ 6,970	\$ 6,849	\$ 5,925
Loss on Sale of Accounts Receivable	\$ 33	\$ 31	\$ 18
Average Variable Discount Rate	5.39%	5.02%	3.23%

	December 31,	
	2007	2006
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	\$ 71	\$ 87
Deferred Revenue from Servicing Accounts Receivable	1	1
Retained Interest if 10% Adverse Change in Uncollectible Accounts	68	85
Retained Interest if 20% Adverse Change in Uncollectible Accounts	66	83

Historical loss and delinquency amounts for the AEP System's customer accounts receivable managed portfolio is as follows:

	December 31,	
	2007	2006
	(in millions)	
Customer Accounts Receivable Retained	\$ 730	\$ 676
Accrued Unbilled Revenues Retained	379	350
Miscellaneous Accounts Receivable Retained	60	44
Allowance for Uncollectible Accounts Retained	(52)	(30)
Total Net Balance Sheet Accounts Receivable	1,117	1,040
Customer Accounts Receivable Securitized	507	536
Total Accounts Receivable Managed	\$ 1,624	\$ 1,576
Net Uncollectible Accounts Written Off	\$ 24	\$ 31

Customer accounts receivable retained and securitized for the domestic electric operating companies are managed by AEP Credit. Miscellaneous accounts receivable have been fully retained and not securitized.

Delinquent customer accounts receivable for the electric utility affiliates that AEP Credit currently factors were \$30 million and \$29 million at December 31, 2007 and 2006, respectively. AEP Credit's delinquent customer accounts receivable represents accounts greater than 30 days past due.

16. STOCK-BASED COMPENSATION

As previously approved by shareholder vote, the Amended and Restated American Electric Power System Long-Term Incentive Plan (LTIP) 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 share awards, which include performance units, restricted shares and restricted stock units. The Board of Directors and shareholders both adopted the original LTIP in 2000 and the amended and restated version in 2005. We did not grant stock options in 2007 or 2006 and granted only 10,000 stock options in 2005. The following sections provide further information regarding each type of stock-based compensation award granted by the Board of Directors.

We adopted SFAS 123 (revised 2004) "Share-Based Payments" (SFAS 123R), effective January 1, 2006.

Stock Options

For all stock options granted, the exercise price equaled or exceeded the market price of AEP's common stock on the date of grant. Stock options were granted with a ten-year term and generally vested, 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. We record compensation cost for stock options over the vesting period based on the fair value on the grant date. The LTIP does not specify a maximum contractual term for stock options.

The total fair value of stock options vested and the total intrinsic value of options exercised are as follows:

Stock Options	Years Ended December 31,		
	2007	2006	2005
	(in thousands)		
Fair Value of Stock Options Vested	\$ 1,377	\$ 3,667	\$ 5,036
Intrinsic Value of Options Exercised (a)	29,389	16,823	12,091

(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 years ended December 31, 2007, 2006 and 2005 is as follows:

	2007		2006		2005	
	Options (in thousands)	Weighted Average Exercise Price	Options (in thousands)	Weighted Average Exercise Price	Options (in thousands)	Weighted Average Exercise Price
Outstanding at January 1,	3,670	\$ 34.41	6,222	\$ 34.16	8,230	\$ 33.29
Granted	-	N/A	-	N/A	10	38.65
Exercised/Converted	(2,454)	35.24	(2,343)	33.12	(1,886)	36.94
Forfeited/Expired	(20)	35.08	(209)	41.58	(132)	31.97
Outstanding at December 31,	1,196	32.69	3,670	34.41	6,222	34.16
Options Exercisable at December 31,	1,193	\$ 32.68	3,411	\$ 34.83	5,199	\$ 35.40

Weighted average exercise price of options:

Granted above Market Price	N/A	N/A	N/A
Granted at Market Price	N/A	N/A	\$ 38.65

The following table summarizes information about AEP stock options outstanding at December 31, 2007.

Options Outstanding

2007 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	539	5.01	\$ 27.38	\$ 10,335
\$30.76 - \$38.65	510	3.61	34.26	6,275
\$44.10 - \$49.00	147	3.36	46.71	(22)
Total (a)	1,196	4.21	32.69	\$ 16,588

(a) Options outstanding are not significantly different from the number of shares expected to vest.

The following table summarizes information about AEP stock options exercisable at December 31, 2007.

Options Exercisable

<u>2007 Range of Exercise Prices</u>	<u>Number Exercisable</u> (in thousands)	<u>Weighted Average Remaining Life</u> (in years)	<u>Weighted Average Exercise Price</u>	<u>Aggregate Intrinsic Value</u> (in thousands)
\$25.73 - \$27.95	539	5.01	\$ 27.38	\$ 10,335
\$30.76 - \$38.65	507	3.59	34.24	6,249
\$44.10 - \$49.00	147	3.36	46.71	(22)
Total	1,193	4.20	32.68	\$ 16,562

We include the proceeds received from exercised stock options in common stock and paid-in capital. No stock options were granted in 2007 or 2006. For options granted in 2005, we estimated the grant date fair value of each option award using a Black-Scholes option-pricing model with weighted average assumptions. We estimated expected volatilities using the historical monthly volatility of our common stock for the thirty-six month period prior to each grant. We also assumed a seven-year average expected term. 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.

We used the following weighted average assumptions to estimate the fair value of AEP stock options granted in 2005.

	<u>2005</u>
Risk Free Interest Rate	4.14%
Expected Volatility	24.63%
Expected Dividend Yield	4.00%
Expected Life	7 years
Weighted average fair value of options:	
Granted above Market Price	N/A
Granted at Market Price	7.60

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 measures, which include both performance and market conditions, 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 paid in cash or stock at the employee's election 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 AEP Career Shares, a form of phantom stock units, 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 paid in cash or stock at the employee's election after the participant's termination of employment. Amounts equivalent to cash dividends on both performance units and AEP Career Shares accrue as additional units. We recorded compensation cost for performance units over the three-year vesting period and the liability, recorded in Employee Benefits and Pension Obligations on our Consolidated Balance Sheets, for both the performance units and AEP Career Shares is adjusted for changes in value. 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.

The Board of Directors awarded performance units and reinvested dividends on outstanding performance units and AEP Career Shares for the years ended December 31, 2007, 2006 and 2005 as follows:

Performance Units	Years Ended December 31,		
	2007	2006	2005
Awarded Units (in thousands)	867	1,635	1,013
Weighted Average Unit Fair Value at Grant Date	\$ 47.64	\$ 39.75	\$ 34.02
Vesting Period (years)	3	3	3

Performance Units and AEP Career Shares (Reinvested Dividends Portion)	Years Ended December 31,		
	2007	2006	2005
Awarded Units (in thousands)	109	118	89
Weighted Average Grant Date Fair Value	\$ 45.93	\$ 36.87	\$ 36.25
Vesting Period (years)	(a)	(a)	(a)

- (a) The vesting period for the reinvested dividends on performance units is equal to the remaining life of the related performance units. Dividends on AEP Career Shares vest immediately upon grant.

Performance scores and final awards are determined and certified by the HR Committee in accordance with the pre-established performance measures. The HR Committee has discretion to reduce or eliminate the value of final awards, but may not increase them. The performance 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.

In January 2008, the HR Committee certified a performance score for the three-year period ended December 31, 2007 of 154.3%. As a result, 1,508,383 performance units were earned. Of this amount 313,781 were mandatorily deferred as AEP Career Shares, 68,107 were voluntarily deferred into the Incentive Compensation Deferral Program and the remainder were paid in cash.

In January 2006, the HR Committee certified a performance score for the three-year period ended December 31, 2005 of 49%. 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.

Due to the anticipated 2004 CEO succession, on December 10, 2003, the HR Committee made performance unit grants for the shortened performance period of December 10, 2003 through December 31, 2004. No performance period ended on December 31, 2006 because this performance period was shorter than the normal three-year period and there were no other performance unit grants in 2003. In 2005, the HR Committee certified a performance factor of 123.1% for performance units granted on December 10, 2003 and 946,789 performance units were mandatorily deferred into AEP stock units. These units had a three year vesting period which ended on December 31, 2006, at which time, 917,032 units vested and the remainder were forfeited due to participant terminations. Of the 917,032 vested units 388,801 were mandatorily deferred as AEP Career Shares and the remainder were paid in cash. These stock units have the same value, dividend rights, vesting and accounting treatment as the performance units that gave rise to them, except that they are no longer subject to performance measures.

The cash payouts for the years ended December 31, 2007, 2006 and 2005 were as follows:

	Years Ended December 31,		
	2007	2006	2005
	(in thousands)		
Cash Payouts for Performance Units	\$ 21,460	\$ 2,630	\$ -
Cash Payouts for AEP Career Share Distributions	1,348	1,079	1,373

Restricted Shares and Restricted Stock Units

The 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 for restricted shares is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of shares granted by the grant date market price of \$30.76. The maximum term for these restricted shares is eight years. The Board of Directors has not granted other restricted shares. Dividends on the restricted shares are paid in cash.

The Board of Directors also grant restricted stock units (RSUs), 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 RSUs accrue as additional RSUs and 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 RSUs is six years from the grant date.

The Board of Directors also grant RSUs with performance vesting conditions to certain employees who are integral to our project to design and build proposed IGCC power plants. In February 2007, the Board of Directors granted RSUs that vest 10% on each of the first three anniversaries of the grant date. An additional 10% vest on the date the IGCC plant achieves substantial completion. Another 20% vest on the date the IGCC plant achieves commercial operations. An additional 20% vest one year after the IGCC plant achieves commercial operations, subject to achievement of plant availability targets. The remaining 20% vest two years after the IGCC plant achieves commercial operations, subject to achievement of plant availability targets.

In January 2006, the Board of Directors granted RSUs with performance vesting conditions. 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.

The Board of Directors awarded RSUs, including units awarded for dividends, for the years ended December 31, 2007, 2006 and 2005 as follows:

	Years Ended December 31,		
	2007	2006	2005
<hr/> Restricted Stock Units <hr/>			
Awarded Units (in thousands)	148	65	166
Weighted Average Grant Date Fair Value	\$ 45.89	\$ 37.47	\$ 35.67

The total fair value and total intrinsic value of restricted shares and restricted stock units vested during the years ended December 31, 2007, 2006 and 2005 were as follows:

	Years Ended December 31,		
	2007	2006	2005
<hr/> Restricted Shares and Restricted Stock Units <hr/>			
	(in thousands)		
Fair Value of Restricted Shares and Restricted Stock Units Vested	\$ 2,711	\$ 3,939	\$ 3,087
Intrinsic Value of Restricted Shares and Restricted Stock Units Vested (a)	3,646	4,686	3,703

(a) Intrinsic value is calculated as market price.

A summary of the status of our nonvested restricted shares and RSUs as of December 31, 2007, and changes during the year ended December 31, 2007 are as follows:

Nonvested Restricted Shares and Restricted Stock Units	Shares/Units	Weighted Average Grant Date Fair Value
	(in thousands)	
Nonvested at January 1, 2007	408	\$ 33.31
Granted	148	45.89
Vested	(79)	34.57
Forfeited	(24)	38.22
Nonvested at December 31, 2007	<u>453</u>	<u>36.93</u>

The total aggregate intrinsic value of nonvested restricted shares and RSUs as of December 31, 2007 was \$21 million and the weighted average remaining contractual life was 2.39 years.

Other Stock-Based Plans

We also have a Stock Unit Accumulation Plan for Nonemployee Directors providing each nonemployee director with AEP stock units as a substantial portion of their quarterly compensation for their services as a director. Amounts equivalent to cash dividends on the stock units accrue as additional AEP stock units. The nonemployee directors vest immediately upon award of the stock units. Stock units are paid in cash upon termination of board service or up to 10 years later if the participant so elects. Cash payments for stock units are calculated based on the average closing price of AEP common stock for the 20 trading days immediately preceding the payment date.

We recorded the compensation cost for stock units when the units are awarded and adjusted the liability for changes in value based on the current 20-day average closing price of AEP common stock at the date of valuation.

We had no material cash payouts for stock unit distributions for the years ended December 31, 2007, 2006 and 2005.

The Board of Directors awarded stock units, including units awarded for dividends, for the years ended December 31, 2007, 2006 and 2005 as follows:

	Years Ended December 31,		
	2007	2006	2005
Stock Unit Accumulation Plan for Non-Employee Directors			
Awarded Units (in thousands)	28	33	27
Weighted Average Grant Date Fair Value	\$ 46.46	\$ 36.66	\$ 36.74

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 years ended December 31, 2007, 2006 and 2005 were as follows:

	Years Ended December 31,		
	2007	2006	2005
Share-based Compensation Plans			
	(in thousands)		
Compensation Cost for Share-based Payment Arrangements (a)	\$ 72,004	\$ 45,842	\$ 28,660
Actual Tax Benefit Realized	25,201	16,045	10,031
Total Compensation Cost Capitalized	18,077	10,953	5,113

(a) Compensation cost for share-based payment arrangements is included in Other Operation and Maintenance on our Consolidated Statements of Income.

During the years ended December 31, 2007, 2006 and 2005, there were no significant modifications affecting any of our share-based payment arrangements.

As of December 31, 2007, there was \$102 million of total unrecognized compensation cost related to unvested share-based compensation arrangements granted under the LTIP. Unrecognized compensation cost related to the performance units and AEP Career Shares will change as the fair value is adjusted each period and forfeitures for all award types are realized. Our unrecognized compensation cost will be recognized over a weighted-average period of 1.65 years.

Cash received from stock options exercised and actual tax benefit realized for the tax deductions from stock options exercised during the years ended December 31, 2007, 2006 and 2005 were as follows:

	Years Ended December 31,		
	2007	2006	2005
Share-based Compensation Plans	(in thousands)		
Cash received from stock options exercised	\$ 86,527	\$ 77,534	\$ 57,546
Actual tax benefit realized for the tax deductions from stock options exercised	10,282	5,825	4,235

Our practice is to use authorized but unissued shares to fulfill share commitments for stock option exercises and RSU 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 LTIP or any combination thereof for this purpose. The number of new shares issued to fulfill vesting RSUs is generally reduced to offset AEP's tax withholding obligation.

17. PROPERTY, PLANT AND EQUIPMENT

We provide for depreciation of Property, Plant and Equipment, excluding coal-mining properties, on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class as follows:

2007	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
	(in millions)			(in years)	(in millions)			(in years)
Production	\$ 11,278	\$ 5,816	2.0 - 3.8%	9 - 132	\$ 8,955	\$ 3,462	2.0 - 5.1%	20 - 121
Transmission	7,392	2,308	1.3 - 3.0%	25 - 87	-	-	N.M.	N.M.
Distribution	12,056	3,116	3.0 - 3.9%	11 - 75	-	-	N.M.	N.M.
CWIP	1,864	(57)	N.M.	N.M.	1,155	2	N.M.	N.M.
Other	2,410	1,105	4.8 - 11.3%	5 - 55	1,035	523	N.M.	N.M.
Total	\$ 35,000	\$ 12,288			\$ 11,145	\$ 3,987		

N.M. = Not Meaningful

2006	Regulated					Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	
	(in millions)			(in years)	(in millions)			(in years)	
Production	\$ 7,892	\$ 4,437	2.6 - 3.8%	30 - 121	\$ 8,895	\$ 3,886	2.57 - 9.15%	20 - 121	
Transmission	7,018	2,332	1.6 - 2.9%	25 - 87	-	-	N.M.	N.M.	
Distribution	11,338	3,121	3.0 - 4.0%	11 - 75	-	-	N.M.	N.M.	
CWIP	1,423	(41)	N.M.	N.M.	2,050	2	N.M.	N.M.	
Other	2,400	1,067	6.7 - 11.5%	24 - 55	1,005	436	N.M.	N.M.	
Total	\$ 30,071	\$ 10,916			\$ 11,950	\$ 4,324			

2005		Regulated		Nonregulated	
Functional Class of Property		Annual Composite Depreciation		Annual Composite Depreciation	
		Rate Ranges		Rate Ranges	
			Depreciable Life Ranges (in years)		Depreciable Life Ranges (in years)
Production		2.7 - 3.8%	30 - 120	2.6 - 3.3%	20 - 120
Transmission		1.7 - 3.0%	25 - 75	N.M.	N.M.
Distribution		3.1 - 4.1%	10 - 75	N.M.	N.M.
Other		5.1 - 16.0%	N.M.	2.0 - 4.9%	2 - 37

N.M. = Not Meaningful

We provide for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. We use either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. We include these costs in the cost of coal charged to fuel expense. The average amortization rate for coal rights and mine development costs was \$0.66 per ton in 2007, 2006 and 2005.

For cost-based rate-regulated operations, the composite depreciation rate generally includes a component for non-asset retirement obligation (non-ARO) removal costs, which is credited to Accumulated Depreciation and Amortization. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability. For nonregulated operations, non-ARO removal costs are expensed as incurred (see "Asset Retirement Obligations (ARO)" section of this note).

Asset Retirement Obligations (ARO)

We implemented SFAS 143 effective January 1, 2003. SFAS 143 requires entities to record a liability at fair value for any legal obligations for future asset retirements when the related assets are acquired or constructed. Upon establishment of a legal liability, SFAS 143 requires a corresponding ARO asset to be established, which will be depreciated over its useful life. Upon settlement of an ARO, any difference between the ARO liability and actual costs is recognized as income or expense.

We adopted FIN 47 during the fourth quarter of 2005. FIN 47 interprets the application of SFAS 143. It clarifies that conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Entities are required to record a liability for the fair value of a conditional ARO if the fair value of the liability can be reasonably estimated. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an ARO.

We completed a review of our FIN 47 conditional ARO during the fourth quarter of 2005 and concluded that we have legal liabilities for asbestos removal and disposal in general buildings and generating plants. In 2005, we recorded \$55 million of conditional ARO in accordance with FIN 47. The cumulative effect of certain retirement costs for asbestos removal related to our regulated operations was generally charged to regulatory liability. Of the \$55 million, we recorded an unfavorable cumulative effect of \$26 million (\$17 million, net of tax) for our nonregulated generation operations related to asbestos removal in the Utility Operations segment.

We have legal obligations for asbestos removal and for the retirement of certain ash ponds, wind farms and certain coal mining facilities, as well as for nuclear decommissioning of our Cook Plant. As of December 31, 2007 and 2006, our ARO liability was \$1.1 billion and \$1 billion, respectively, and included \$846 million and \$803 million, respectively, for nuclear decommissioning of the Cook Plant. As of December 31, 2007 and 2006, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled \$1.1 billion and \$1 billion, respectively, relating to the Cook Plant and are recorded in Spent Nuclear Fuel and Decommissioning Trusts on our Consolidated Balance Sheets.

We have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets, as a result of certain easements on property on which we have assets. Generally, such easements are perpetual and require only the retirement and removal of our assets upon the cessation of the property's use. We do not estimate the retirement for such easements because we plan to use our facilities indefinitely. The retirement obligation would only be recognized if and when we abandon or cease the use of specific easements, which is not expected.

The following is a reconciliation of the 2007 and 2006 aggregate carrying amounts of ARO:

	Carrying Amount of ARO (in millions)
ARO at December 31, 2005	\$ 946
Accretion Expense	63
Liabilities Incurred	9
Liabilities Settled	(20)
Revisions in Cash Flow Estimates	30
ARO at December 31, 2006 (a)	<u>1,028</u>
Accretion Expense	58
Liabilities Incurred	4
Liabilities Settled	(17)
Revisions in Cash Flow Estimates	5
ARO at December 31, 2007 (b)	<u><u>\$ 1,078</u></u>

- (a) The current portion of our ARO, totaling \$5 million, is included in Other in the Current Liabilities section of our 2006 Consolidated Balance Sheet.
- (b) The current portion of our ARO, totaling \$3 million, is included in Other in the Current Liabilities section of our 2007 Consolidated Balance Sheet.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

The amounts of AFUDC were \$33 million, \$30 million and \$21 million in 2007, 2006 and 2005, respectively, and are included in Allowance For Equity Funds Used During Construction on our Consolidated Statements of Income. The amounts of interest capitalized and allowance for borrowed funds used during construction were \$79 million, \$82 million and \$36 million in 2007, 2006 and 2005, respectively, and are credited to Interest Expense on our Consolidated Statements of Income.

Jointly-owned Electric Utility Plant

We have generating units that are jointly-owned with nonaffiliated companies. We are obligated to pay a share of the costs of these jointly-owned facilities in the same proportion as our ownership interest. Our proportionate share of the operating costs associated with such facilities is included in our Consolidated Statements of Income and the investments and accumulated depreciation are reflected in our Consolidated Balance Sheets under Property, Plant and Equipment as follows:

Company's Share at December 31, 2007					
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress (h)	Accumulated Depreciation
				(in millions)	
W.C. Beckjord Generating Station (Unit No. 6) (a)	Coal	12.5 %	\$ 16	\$ 1	\$ 8
Conesville Generating Station (Unit No. 4) (b)	Coal	43.5	84	84	50
J.M. Stuart Generating Station (c)	Coal	26.0	296	157	134
Wm. H. Zimmer Generating Station (a)	Coal	25.4	763	1	324
Dolet Hills Generating Station (Unit No. 1) (d)	Lignite	40.2	241	11	175
Flint Creek Generating Station (Unit No. 1) (e)	Coal	50.0	98	3	60
Pirkey Generating Station (Unit No. 1) (e)	Lignite	85.9	486	4	325
Oklaunion Generating Station (Unit No. 1) (f)	Coal	70.3	379	2	186
Transmission	N/A	(g)	63	6	44

Company's Share at December 31, 2006					
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress (h)	Accumulated Depreciation
				(in millions)	
W.C. Beckjord Generating Station (Unit No. 6) (a)	Coal	12.5 %	\$ 16	\$ -	\$ 8
Conesville Generating Station (Unit No. 4) (b)	Coal	43.5	85	32	49
J.M. Stuart Generating Station (c)	Coal	26.0	284	102	128
Wm. H. Zimmer Generating Station (a)	Coal	25.4	751	5	302
Dolet Hills Generating Station (Unit No. 1) (d)	Lignite	40.2	240	5	167
Flint Creek Generating Station (Unit No. 1) (e)	Coal	50.0	97	2	57
Pirkey Generating Station (Unit No. 1) (e)	Lignite	85.9	481	5	310
Oklaunion Generating Station (Unit No. 1) (f)	Coal	78.1	417	3	200
Transmission	N/A	(g)	63	-	42

- (a) Operated by Duke Energy Corporation, a nonaffiliated company.
- (b) Operated by CSPCo.
- (c) Operated by The Dayton Power & Light Company, a nonaffiliated company.
- (d) Operated by Cleco Corporation, a nonaffiliated company.
- (e) Operated by SWEPCo.
- (f) TCC's 7.8% interest in Oklaunion Generating Station amounted to \$40 million at December 31, 2006. These amounts were included in Assets Held for Sale on our 2006 Consolidated Balance Sheet. TCC's interest in Oklaunion Generating Station was sold in 2007. Oklaunion Generating Station is operated by PSO.
- (g) Varying percentages of ownership.
- (h) Primarily relates to environmental upgrades, including the installation of flue gas desulfurization projects at Conesville Generating Station and J.M. Stuart Generating Station.

N/A = Not Applicable

18. UNAUDITED QUARTERLY FINANCIAL INFORMATION

In our opinion, the unaudited quarterly information reflects all normal and recurring accruals and adjustments necessary for a fair presentation of our results of operations for interim periods. Quarterly results are not necessarily indicative of a full year's operations because of various factors. Our unaudited quarterly financial information is as follows:

	2007 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in millions – except per share amounts)			
Revenues	\$ 3,169	\$ 3,146	\$ 3,789	\$ 3,276
Operating Income (a)	545	549	798	427
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change (a)	271	257	407	209
Discontinued Operations, Net of Tax	-	2	-	22
Income Before Extraordinary Loss and Cumulative Effect of Accounting Change (a)	271	259	407	231
Extraordinary Loss, Net of Tax (b)	-	(79)	-	-
Net Income (a)	271	180	407	231
Basic Earnings (Loss) per Share:				
Earnings per Share Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change (c)	0.68	0.64	1.02	0.52
Discontinued Operations, Net of Tax (d)	-	0.01	-	0.06
Earnings per Share Before Extraordinary Loss and Cumulative Effect of Accounting Change	0.68	0.65	1.02	0.58
Extraordinary Loss per Share	-	(0.20)	-	-
Earnings per Share	0.68	0.45	1.02	0.58
Diluted Earnings (Loss) per Share:				
Earnings per Share Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	0.68	0.64	1.02	0.52
Discontinued Operations, Net of Tax	-	0.01	-	0.05
Earnings per Share Before Extraordinary Loss and Cumulative Effect of Accounting Change	0.68	0.65	1.02	0.57
Extraordinary Loss per Share	-	(0.20)	-	-
Earnings per Share	0.68	0.45	1.02	0.57

	2006 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in millions – except per share amounts)			
Revenues	\$ 3,108	\$ 2,936	\$ 3,594	\$ 2,984
Operating Income	689	371	535	371
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	378	172	265	177
Discontinued Operations, Net of Tax	3	3	-	4
Income Before Extraordinary Loss and Cumulative Effect of Accounting Change	381	175	265	181
Net Income	381	175	265	181
Basic Earnings per Share:				
Earnings per Share Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	0.96	0.44	0.67	0.45
Discontinued Operations, Net of Tax	0.01	-	-	0.01
Earnings per Share Before Extraordinary Loss and Cumulative Effect of Accounting Change	0.97	0.44	0.67	0.46
Earnings per Share	0.97	0.44	0.67	0.46
Diluted Earnings per Share:				
Earnings per Share Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change (e)	0.95	0.43	0.67	0.44
Discontinued Operations, Net of Tax (f)	0.01	0.01	-	0.02
Earnings per Share Before Extraordinary Loss and Cumulative Effect of Accounting Change	0.96	0.44	0.67	0.46
Earnings per Share	0.96	0.44	0.67	0.46

- (a) See “Oklahoma 2007 Ice Storms” section of Note 4 for discussion of expenses incurred from ice storms in January and December 2007.
- (b) See “Virginia Restructuring” in “Extraordinary Items” section of Note 2 for a discussion of the extraordinary loss booked in the second quarter of 2007.
- (c) Amounts for 2007 do not add to \$2.87 for Basic Earnings per Share Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change due to rounding.
- (d) Amounts for 2007 do not add to \$0.06 for Basic Earnings per Share for Discontinued Operations, Net of Tax due to rounding.
- (e) Amounts for 2006 do not add to \$2.50 for Diluted Earnings per Share Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change due to rounding.
- (f) Amounts for 2006 do not add to \$0.03 for Diluted Earnings per Share for Discontinued Operations, Net of Tax due to rounding.