Appendix A to the
Proxy Statement

American Electric Power

2008 Annual Report

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

AMERICAN ELECTRIC POWER

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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 electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEP Foundation	AEP charitable organization created in 2005 for charitable contributions in the communities in which AEP's subsidiaries operate.
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 System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP West companies	PSO, SWEPCo, TCC and TNC.
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.
AEPES	AEP Energy Services, Inc., a subsidiary of AEP Resources, Inc.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
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.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo that is consolidated under FIN 46R.
DOE	United States Department of Energy.
DOJ	United States Department of Justice.
DSM	Demand-side Management.
E&R	Environmental compliance and transmission and distribution system reliability.

Term	Meaning
EaR	Earnings at Risk, a method to quantify risk exposure.
EIS	Energy Insurance Services, Inc., a protected cell insurance company that AEP consolidates under FIN 46R.
EITF	Financial Accounting Standards Board’s Emerging Issues Task Force.
EITF 06-10	EITF Issue No. 06-10 “Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements.”
EPS	Earnings Per Share.
ERCOT	Electric Reliability Council of Texas.
ERISA	Employee Retirement Income Security Act of 1974, as amended.
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.
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.
FGD	Flue Gas Desulfurization or Scrubbers
FIN	FASB Interpretation No.
FIN 46R	FIN 46R, “Consolidation of Variable Interest Entities.”
FIN 48	FIN 48, “Accounting for Uncertainty in Income Taxes” and FASB Staff Position FIN 48-1 “Definition of *Settlement* in FASB Interpretation No. 48.”
FSP	FASB Staff Position.
FSP FIN 39-1	FSP FIN 39-1, “Amendment of FASB Interpretation No. 39.”
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
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.
Interconnection Agreement	Agreement, dated July 6, 1951, as amended, by and among APCo, CSPCo, I&M, KPCo and OPCo, defining the sharing of costs and benefits associated with their respective generating plants.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
JMG	JMG Funding LP, a financing company that OPCo consolidates under FIN 46R.
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.
LPSC	Louisiana Public Service Commission.

Term	Meaning
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.
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.
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.
PM	Particulate Matter.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
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.
Sabine	Sabine Mining Company, a lignite mining company that SWEPCo consolidates under FIN 46R.
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 107	Statement of Financial Accounting Standards No. 107, "Disclosures about Fair Value of Financial Investments."
SFAS 109	Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes."

Term	Meaning
SFAS 133	Statement of Financial Accounting Standards No. 133, “Accounting for Derivative Instruments and Hedging Activities.”
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.”
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.
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.
TCRR	Transmission Cost Recovery Rider.
TEM	SUEZ Energy Marketing NA, Inc. (formerly known as Tractebel Energy Marketing, Inc.).
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
True-up Proceeding	A filing made under the Texas Restructuring Legislation to finalize the amount of stranded costs and other true-up items and the recovery of such amounts.
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:

- The economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns.
- Inflationary or deflationary interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates.
- The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.
- 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 including our ability to restore Cook Plant Unit 1 in a timely manner.
- 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 and transmission line facilities (including our ability to obtain any necessary regulatory or siting approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) 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.
- 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 markets.
- 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 implementation of the recently passed utility law in Ohio and the allocation of costs within RTOs, including PJM and SPP.
- 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 and the impact on future funding requirements.
- 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.

AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information.

AEP COMMON STOCK AND DIVIDEND INFORMATION

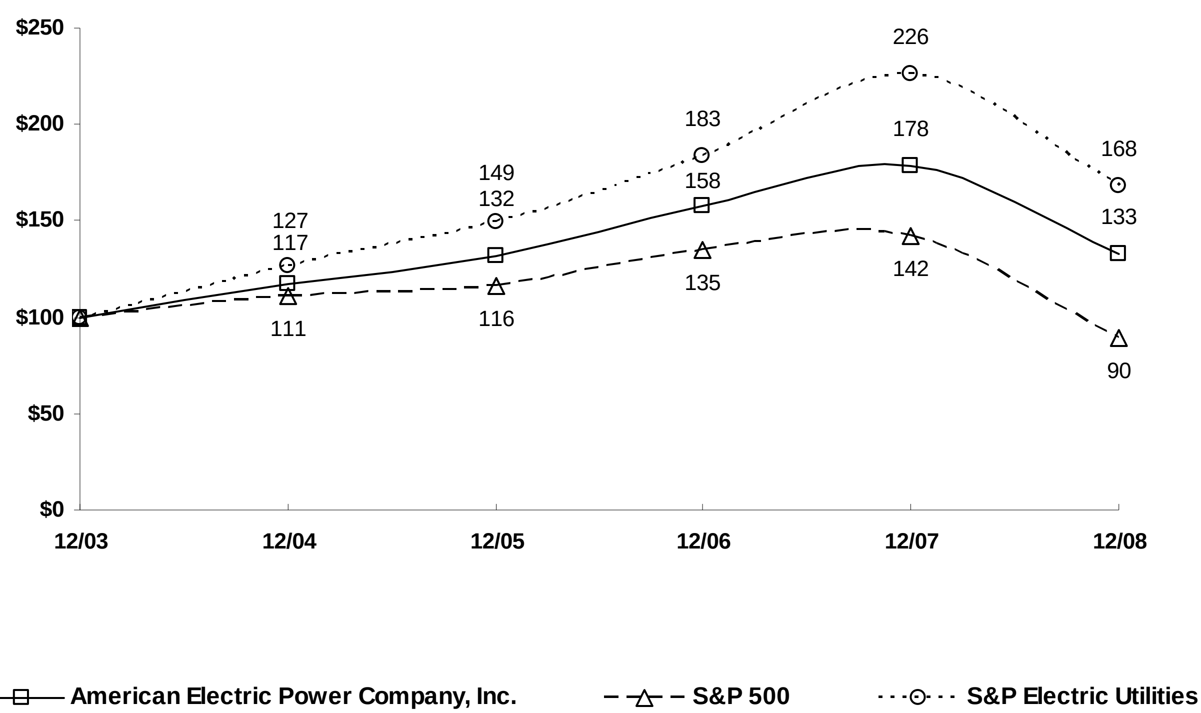
The AEP common stock quarterly high and low sales prices, quarter-end closing price and the cash dividends paid per share are shown in the following table:

Quarter Ended	High	Low	Quarter-End Closing Price	Dividend
December 31, 2008	$ 37.28	$ 25.54	$ 33.28	$ 0.41
September 30, 2008	41.60	34.86	37.03	0.41
June 30, 2008	45.95	39.46	40.23	0.41
March 31, 2008	49.11	39.35	41.63	0.41
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

AEP common stock is traded principally on the New York Stock Exchange. At December 31, 2008, AEP had approximately 100,000 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 12/31/03 in stock & index-including reinvestment of dividends.
Fiscal year ending December 31.

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

	2008	2007	2006	2005	2004
			(in millions)		
STATEMENTS OF INCOME DATA					
Total Revenues	$ 14,440	$ 13,380	$ 12,622	$ 12,111	$ 14,245
Operating Income	$ 2,787	$ 2,319	$ 1,966	$ 1,927	$ 1,983
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	$ 1,368	$ 1,144	$ 992	$ 1,029	$ 1,127
Discontinued Operations, Net of Tax	12	24	10	27	83
Income Before Extraordinary Loss and Cumulative Effect of Accounting Change	1,380	1,168	1,002	1,056	1,210
Extraordinary Loss, Net of Tax	-	(79)	-	(225)(a)	(121)
Cumulative Effect of Accounting Change, Net of Tax	-	-	-	(17)	-
Net Income	$ 1,380	$ 1,089	$ 1,002	$ 814	$ 1,089
BALANCE SHEETS DATA			(in millions)		
Property, Plant and Equipment	$ 49,710	$ 46,145	$ 42,021	$ 39,121	$ 37,294
Accumulated Depreciation and Amortization	16,723	16,275	15,240	14,837	14,493
Net Property, Plant and Equipment	$ 32,987	$ 29,870	$ 26,781	$ 24,284	$ 22,801
Total Assets	$ 45,155	$ 40,319 (b)	$ 37,877 (b)	$ 35,662 (b)	$ 34,388 (b)
Common Shareholders' Equity	$ 10,693	$ 10,079	$ 9,412	$ 9,088	$ 8,515
Cumulative Preferred Stocks of Subsidiaries	$ 61	$ 61	$ 61	$ 61	$ 127
Long-term Debt (c)	$ 15,983	$ 14,994	$ 13,698	$ 12,226	$ 12,287
Obligations Under Capital Leases (c)	$ 325	$ 371	$ 291	$ 251	$ 243
COMMON STOCK DATA					
Basic Earnings (Loss) per Common Share:					
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	$ 3.40	$ 2.87	$ 2.52	$ 2.64	$ 2.85
Discontinued Operations, Net of Tax	0.03	0.06	0.02	0.07	0.21
Income Before Extraordinary Loss and Cumulative Effect of Accounting Change	3.43	2.93	2.54	2.71	3.06
Extraordinary Loss, Net of Tax	-	(0.20)	-	(0.58)	(0.31)
Cumulative Effect of Accounting Change, Net of Tax	-	-	-	(0.04)	-
Basic Earnings Per Share	$ 3.43	$ 2.73	$ 2.54	$ 2.09	$ 2.75
Weighted Average Number of Basic Shares Outstanding (in millions)	402	399	394	390	396
Market Price Range:					
High	$ 49.11	$ 51.24	$ 43.13	$ 40.80	$ 35.53
Low	$ 25.54	$ 41.67	$ 32.27	$ 32.25	$ 28.50
Year-end Market Price	$ 33.28	$ 46.56	$ 42.58	$ 37.09	$ 34.34
Cash Dividends Paid per Common Share	$ 1.64	$ 1.58	$ 1.50	$ 1.42	$ 1.40
Dividend Payout Ratio	47.8%	57.9%	59.1%	67.9%	50.9%
Book Value per Share	$ 26.35	$ 25.17	$ 23.73	$ 23.08	$ 21.51

(a) Extraordinary Loss, Net of Tax for 2005 reflects TCC's stranded cost.

(b) Includes reclassification of assets due to FSP FIN 39-1 adoption effective in 2008. See "FSP FIN 39-1" section of Note 2.

(c) Includes portion due within one year.

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:

- Almost 39,000 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 commodity transportation assets (more than 9,000 railcars, 2,978 barges, 58 towboats, 25 harbor boats and a coal handling terminal with 20 million tons of annual capacity).

EXECUTIVE OVERVIEW

OUTLOOK FOR 2009

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

- Hold operation and maintenance expense relatively flat as compared to 2008.
- Significantly reduce our capital expenditures while continuing construction of additional new generation.
- Aggressively seek rate relief by developing rate plans that obtain favorable and timely resolutions to our rate proceedings.
- Continue developing strong regulatory relationships through operating company interaction with the various regulatory bodies.

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

- Domestic and international economic slowdowns.
- Access to capital markets to support our proposed capital expenditures.
- Intervention by consumer advocates in current and future state and FERC regulatory proceedings who try to keep rates down at the expense of a fair return.
- Wholesale market volatility.
- The return to service of Cook Plant Unit 1 and overall plant availability.
- Managing our overall generating fleet to maximize our off-system sales opportunities despite the loss of production from Cook Plant Unit 1.
- Fuel cost volatility and timely fuel cost recovery, including related transportation costs.
- Managing the effects of potential environmental legislation and regulation regarding carbon dioxide and other emissions on our existing generating fleet.
- Expanding our generating fleet while complying with potential new emission restrictions on the construction of future plants.
- Weather-related system reliability and utilization.

Regulatory Activity

In 2009, our significant regulatory activities will include:

- Achieving favorable regulatory results in Ohio under Senate Bill 221.
- Maintaining adequate returns in AEP's retail jurisdictions by filing for rate increases, where necessary.
- Continuing progress on major transmission projects by:
  - Securing favorable regulatory treatment for transmission projects.
  - Obtaining successful outcomes in siting and right of way filings.
  - Seeking proper cost recovery within and across RTOs.

Capital Markets

As a result of domestic and world economic slowdowns in 2008, the financial markets have become increasingly unstable and constrained at both a global and domestic level. This systemic marketplace distress is impacting our access to capital, liquidity, asset valuations in our trust funds, the creditworthy status of customers, suppliers and trading partners and our cost of capital. Our financial staff actively manages these factors with oversight from our risk committee. The uncertainties in the capital markets could have significant implications since we rely on continuing access to capital to fund operations and capital expenditures.

The current credit markets are constraining our ability to issue new debt, including commercial paper, and to refinance existing debt. We cannot predict the length of time the current capital market situation will continue or its impact on future operations and our ability to issue debt at reasonable interest rates. If market conditions improve, we plan to repay portions of the amounts drawn under the credit facilities and issue commercial paper and long-term debt.

We believe that we have adequate liquidity to support our planned business operations and construction program through 2009 due to the following:

- We have $1.9 billion in aggregate available credit facility commitments as of December 31, 2008. These commitments include 27 different banks with no one bank having more than 10% of our total bank commitments. In April 2009, $338 million of our $1.9 billion in available credit facility commitments will expire. As of December 31, 2008, our total cash and cash equivalents were $411 million.
- Of our $16 billion of long-term debt as of December 31, 2008, approximately $300 million will mature in 2009 (approximately 1.9% of our outstanding long-term debt as of December 31, 2008). We intend to refinance these maturities. The $300 million of 2009 maturities exclude payments due for securitization bonds which we recover directly from ratepayers.
- We will receive a favorable impact in 2009 due to base rate increases in Oklahoma and Virginia and an expected base rate increase in Indiana. We are currently awaiting a decision on the Ohio ESP filings.
- We believe that our projected cash flows from operating activities are sufficient to support our ongoing operations.

Approximately $1.5 billion of outstanding long-term debt will mature in 2010, excluding payments due for securitization bonds which we recover directly from ratepayers. In conjunction with the upcoming resolution of the Ohio ESPs, we will be reevaluating our operating and financial plans and those plans could possibly include debt and/or equity issuances.

We have significant investments in several trust funds to provide for future payments of pensions, OPEB, nuclear decommissioning and spent nuclear fuel disposal. Although all of our trust funds' investments are diversified and managed in compliance with all laws and regulations, the value of the investments in these trusts declined substantially in 2008 due to decreases in domestic and international equity markets. Although the asset values are currently lower, this has not affected the funds' ability to make their required payments. As of December 31, 2008, the decline in pension asset values will not require us to make a contribution under ERISA in 2009. We currently estimate that we will need to make minimum contributions to our pension trust of $365 million in 2010 and $258 million in 2011. However, estimates may vary significantly based on market returns, changes in actuarial assumptions and other factors.

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. Our risk management organization monitors these exposures on a daily basis to limit our economic and financial statement impact on a counterparty basis. At December 31, 2008, our credit exposure net of collateral was approximately $764 million of which approximately 92% is to investment grade counterparties. At December 31, 2008, our exposure to financial institutions was $80 million, which represents 11% of our total credit exposure net of collateral (all investment grade).

Economic Slowdown

Following the indications of a slowing economy in 2007, the U.S. economy experienced what some have labeled a financial crisis in 2008. These economic troubles impacted and will continue to impact our residential, commercial and industrial sales as well as sales opportunities in the wholesale market. Most sections of our service territories are experiencing slowdowns in new construction, resulting in our residential and commercial customer base growing at a decreased rate. Starting in the fourth quarter of 2008, various sections of our service territories also experienced decreases in industrial sales due to temporary shutdowns and reduced shifts by some of our large industrial customers. We expect these trends to continue throughout 2009.

Capital Expenditures

Due to recent capital market instability and the economic slowdown, we reduced our planned capital expenditures for 2009 by $750 million:

	Original 2009 Capital Expenditure Projection	$750 Million Budget Reduction	Revised 2009 Capital Expenditure Budget
		(in millions)	
New Generation	$ 469	$ (234)	$ 235
Environmental	668	(232)	436
Other Generation	643	(37)	606
Transmission	476	56	532
Distribution	949	(263)	686
Corporate	129	(40)	89
Total	$ 3,334	$ (750)	$ 2,584

The reduction in capital spending will reduce our need to access the capital markets in 2009. While many of these cutbacks involve the delay of certain capital projects into future years, these reductions will not jeopardize the reliability of the AEP System. Projected capital expenditures for 2010 are currently under review.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, likely caused by blade failure, which resulted in a fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately $330 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance and the regulatory process. Our current analysis indicates that with successful repairs and timely parts deliveries, Unit 1 could resume operations as early as September 2009 at reduced power. If the rotors cannot be repaired, replacement of parts will extend the outage into 2010.

Fuel Costs

Coal prices increased by approximately 29% in 2008 due to several factors including escalating market prices and increased demand, primarily in our eastern region as a result of the expiration of lower-priced coal and transportation contracts being replaced with higher-priced contracts. During 2008, we had price risk exposure in Ohio, representing approximately 20% of our fuel costs. For 2009, we expect our coal costs to increase by approximately 15%. We have active fuel cost recovery mechanisms in all of our jurisdictions except Ohio. We expect the PUCO to reinstate a fuel cost recovery mechanism. An order on the ESPs is expected before the end of the first quarter of 2009. In January 2009, CSPCo and OPCo filed an application requesting the PUCO to authorize deferred fuel accounting beginning January 1, 2009.

2008 RESULTS

We had many accomplishments in 2008, including strong earnings despite the economic climate. Our earnings per-share increased in 2008 to $3.43 per share. We completed construction of new generating units at our Southwestern Station and Riverside Station in Oklahoma and continued construction of the Stall Unit, Turk Plant and Dresden Plant generating facilities in Louisiana, Arkansas and Ohio, respectively. We also continued our pursuit of joint venture opportunities to invest in transmission facilities in PJM, ERCOT and other regions.

RESULTS OF OPERATIONS

Segments

Our primary business is our electric utility operations. Within our Utility Operations segment, we centrally dispatch generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. While our Utility Operations segment remains our primary business segment, other segments include our AEP River Operations segment with significant barging activities and our Generation and Marketing segment, which includes our nonregulated generating, marketing and risk management activities primarily 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.

AEP River Operations

- Commercial barging operations that annually transport approximately 33 million tons of coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers. Approximately 38% of the barging is for transportation of agricultural products, 30% for coal, 13% for steel and 19% for other commodities. Effective July 30, 2008, AEP MEMCO LLC's name was changed to AEP River Operations LLC.

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 7.

The table below presents our consolidated Income Before Discontinued Operations and Extraordinary Loss by segment for the years ended December 31, 2008, 2007 and 2006.

	Years Ended December 31, 2008	2007	2006
		(in millions)	
Utility Operations	$ 1,115	$ 1,031	$ 1,028
AEP River Operations	55	61	80
Generation and Marketing	65	67	12
All Other (a)	133	(15)	(128)
Income Before Discontinued Operations and Extraordinary Loss	$ 1,368	$ 1,144	$ 992

(a) All Other includes:

- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.
- Tax and interest expense adjustments related to our UK operations which were sold in 2004 and 2002.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts are financial derivatives which will gradually settle and completely expire in 2011.
- Other energy supply related businesses, including the Plaquemine Cogeneration Facility, which was sold in 2006. See "Plaquemine Cogeneration Facility" section of Note 7.
- The 2008 cash settlement of a purchase power and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in the fourth quarter of 2006. The cash settlement of $255 million ($164 million, net of tax) is included in Net Income.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

AEP Consolidated

2008 Compared to 2007

Income Before Discontinued Operations and Extraordinary Loss in 2008 increased $224 million compared to 2007 primarily due to income from the cash settlement received in 2008 related to a disputed purchase power and sale agreement with TEM, the 2008 deferral of Oklahoma ice storm expenses incurred in 2007 and base rate increases in our Ohio, Texas and Virginia service territories. These increases over 2007 were partially offset by higher interest expense and fuel expense and a provision for refund recorded to reflect the impact of an order issued in November 2008 by the FERC regarding the affiliate allocation of off-system sales margins under the SIA and the CSW Operating Agreement.

Average basic shares outstanding increased to 402 million in 2008 from 399 million in 2007 primarily due to the issuance of shares under our incentive compensation and dividend reinvestment plans. Actual shares outstanding were 406 million as of December 31, 2008. In 2008, we contributed 1,250,000 shares of common stock held in treasury to the AEP Foundation.

2007 Compared to 2006

Income Before Discontinued Operations and Extraordinary Loss 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.

Our results of operations are discussed below by operating segment.

Utility Operations

Our Utility Operations segment includes 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,		
	2008	**2007**	**2006**
		(in millions)	
Revenues	$ 13,566	$ 12,655	$ 12,011
Fuel and Purchased Power	5,622	4,838	4,669
Gross Margin	7,944	7,817	7,342
Depreciation and Amortization	1,450	1,483	1,435
Other Operating Expenses	4,114	4,129	3,843
Operating Income	2,380	2,205	2,064
Other Income, Net	169	102	177
Interest Expense and Preferred Stock Dividend Requirements	919	790	670
Income Tax Expense	515	486	543
Income Before Discontinued Operations and Extraordinary Loss	$ 1,115	$ 1,031	$ 1,028

Summary of KWH Energy Sales for Utility Operations
For the Years Ended December 31, 2008, 2007 and 2006

	2008	2007	2006
	(in millions of KWH)		
Retail:			
Residential	49,011	49,176	47,222
Commercial	40,078	40,545	38,579
Industrial	58,170	57,566	53,914
Miscellaneous	2,501	2,565	2,653
Total Retail	149,760	149,852	142,368
Wholesale	42,830	42,917	44,564
Texas Wires – Energy delivered to customers served by TNC and TCC in ERCOT	27,075	26,682	26,382
Total KWHs	219,665	219,451	213,314

Cooling degree days and heating degree days are metrics commonly used in the utility industry as a measure of the impact of weather on net income. In general, degree day changes in our eastern region have a larger effect on net income 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, 2008, 2007 and 2006

	2008	2007	2006
	(in degree days)		
Eastern Region			
Actual – Heating (a)	3,148	3,014	2,477
Normal – Heating (b)	3,018	3,042	3,078
Actual – Cooling (c)	936	1,266	923
Normal – Cooling (b)	986	978	985
Western Region (d)			
Actual – Heating (a)	1,613	1,559	1,172
Normal – Heating (b)	1,561	1,588	1,605
Actual – Cooling (c)	2,011	2,244	2,430
Normal – Cooling (b)	2,173	2,181	2,175

(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.

Reconciliation of Year Ended December 31, 2007 to Year Ended December 31, 2008
Income from Utility Operations Before Discontinued Operations and Extraordinary Loss
(in millions)

Year Ended December 31, 2007		$ 1,031
Changes in Gross Margin:		
Retail Margins	114	
Off-system Sales	(45)	
Transmission Revenues	33	
Other	25	
Total Change in Gross Margin		127
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	35	
Gain on Dispositions of Assets, Net	(19)	
Depreciation and Amortization	33	
Taxes Other Than Income Taxes	(1)	
Interest Income	21	
Carrying Costs Income	32	
Other Income, Net	14	
Interest Expense	(129)	
Total Change in Operating Expenses and Other		(14)
Income Tax Expense		(29)
Year Ended December 31, 2008		$ 1,115

Income from Utility Operations Before Discontinued Operations and Extraordinary Loss increased $84 million to $1,115 million in 2008. The key drivers of the increase were a $127 million increase in Gross Margin offset by a $14 million increase in Operating Expenses and Other and a $29 million increase in Income Tax Expense.

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

- Retail Margins increased $114 million primarily due to the following:
  - A $206 million increase related to net rate increases implemented in our Ohio jurisdictions, a $53 million increase related to recovery of E&R costs in Virginia and construction financing costs in West Virginia, a $25 million net increase in rates in Oklahoma, a $21 million increase in base rates in Texas and an $18 million increase in base rates in Virginia.
  - A $99 million net increase due to adjustments recorded in 2007 related to the 2007 Virginia base rate case which included a second quarter 2007 provision for revenue refund.
  - A $50 million increase related to increased usage by Ormet, an industrial customer in Ohio. See “Ormet” section of Note 4.
  - A $40 million net increase due to coal contract amendments in 2008.
  - An $18 million decrease in the sharing of off-system sales margins with customers due to a decrease in total off-system sales.
  - A $17 million increase due to a 2007 provision related to a SWEPCo Texas fuel reconciliation proceeding.

  These increases were partially offset by:
  - A $213 million increase in fuel and consumable expenses in Ohio. CSPCo and OPCo have applied for an active fuel clause in their Ohio Electric Security Plan filings to be effective January 1, 2009.
  - A $102 million decrease due to the December 2008 provision for refund of off-system sales margins as ordered by the FERC related to the SIA. See “Allocation of Off-system Sales Margins” section of Note 4.
  - A $65 million decrease in usage primarily due to a 26% decrease in cooling degree days in our eastern region and a 10% decrease in cooling degree days in our western region.

  - A $40 million net decrease in retail sales primarily due to lower industrial sales in Indiana, Ohio and Virginia as a result of the economic slowdown in the second half of 2008.
- Margins from Off-system Sales decreased $45 million primarily due to higher trading margins realized in 2007 and the favorable effects of a fuel reconciliation in our western service territory in 2007. This decrease was partially offset by higher physical off-system sales in our eastern territory as the result of higher realized prices and higher PJM capacity revenues.
- Transmission Revenues increased $33 million primarily due to increased rates.
- Other Revenues increased $25 million primarily due to increased third-party engineering and construction work, an increase in pole attachment revenue and an unfavorable provision for TCC for the refund of bonded rates recorded in 2007.

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

- Other Operation and Maintenance expenses decreased $35 million primarily due to the following:
  - An $84 million decrease due to distribution expense recorded in 2007 for ice storm costs incurred in January and December 2007 and a $74 million decrease related to the deferral of these costs in the first quarter of 2008. See "Oklahoma 2007 Ice Storms" section of Note 4.
  - A $77 million decrease related to the recording of NSR settlement costs in September 2007. We are pursuing recovery of these expenses in certain of our affected jurisdictions.
  - A $9 million decrease related to the establishment of a regulatory asset in the third quarter of 2008 for Virginia's share of previously expensed NSR settlement costs.

  These decreases were partially offset by:
  - A $60 million increase in recoverable PJM expenses in Ohio.
  - A $38 million increase in tree trimming, reliability and other transmission and distribution expenses.
  - A $28 million increase in generation plant operations and maintenance expense.
  - A $28 million increase in recoverable customer account expenses related to the Universal Service Fund for Ohio customers who qualify for payment assistance.
  - A $22 million increase due to storm costs incurred in 2008 by SWEPCo and I&M.
  - A $13 million increase in maintenance expense at the Cook Plant.
  - A $12 million increase due to the amortization of deferred 2007 Oklahoma ice storm costs in 2008.
  - A $10 million increase related to the write-off of the unrecoverable pre-construction costs for PSO's cancelled Red Rock Generating Facility in the first quarter of 2008.
- Gain on Disposition of Assets, Net decreased $19 million primarily due to the expiration of the earnings sharing agreement with Centrica from the sale of our Texas REPs in 2002. In 2007, we received the final earnings sharing payment of $20 million.
- Depreciation and Amortization expense decreased $33 million primarily due to lower commission-approved depreciation rates in Indiana, Michigan, Oklahoma and Texas and lower Ohio regulatory asset amortization, partially offset by higher depreciable property balances and prior year adjustments related to the Virginia base rate case.
- Interest Income increased $21 million primarily due to the favorable effect of claims for refund filed with the IRS.
- Carrying Costs Income increased $32 million primarily due to increased carrying cost income on cost deferrals in Virginia and Oklahoma.
- Other Income, Net increased $14 million primarily due to an increase in the equity component of AFUDC as a result of generation projects under construction.
- Interest Expense increased $129 million primarily due to additional debt issued and higher interest rates on variable rate debt and interest expense of $47 million on off-system sales margins in accordance with the FERC's order related to the SIA. See "Allocation of Off-system Sales Margins" section of Note 4.
- Income Tax Expense increased $29 million due to an increase in pretax income.

2007 Compared to 2006

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

Year Ended December 31, 2006		$ 1,028
Changes in Gross Margin:		
Retail Margins	372	
Off-system Sales	69	
Transmission Revenues	25	
Other	9	
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)	
Interest Income	(14)	
Carrying Costs Income	(63)	
Other Income, Net	2	
Interest Expense	(120)	
Total Change in Operating Expenses and Other		(529)
Income Tax Expense		57
Year Ended December 31, 2007		$ 1,031

Income from Utility Operations Before Discontinued Operation and Extraordinary Loss 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.
  - 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.

- 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 our eastern region.
- 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 Tax Expense 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 $63 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 Expense increased $120 million primarily due to additional debt issued in 2006 and 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.

AEP River Operations

2008 Compared to 2007

Income Before Discontinued Operations and Extraordinary Loss from our AEP River Operations segment decreased from $61 million in 2007 to $55 million in 2008 primarily due to rising diesel fuel prices, travel restrictions caused by significant flooding on various internal waterways throughout 2008, the impact of Hurricanes Ike and Gustav and other adverse operating conditions. Additionally, decreases in import demand and grain export demand have resulted in lower freight demand, largely the result of a slowing U.S. economy.

2007 Compared to 2006

Income Before Discontinued Operations and Extraordinary Loss from our AEP River Operations segment decreased from $80 million in 2006 to $61 million in 2007. AEP River Operations 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.

Generation and Marketing

2008 Compared to 2007

Income Before Discontinued Operations and Extraordinary Loss from our Generation and Marketing segment decreased from $67 million in 2007 to $65 million in 2008 primarily due to the sale in 2007 of our equity investment in Sweeny and related contracts which resulted in $37 million of after-tax income offset by higher gross margins from marketing activities and improved plant performance and hedging activities from our share of the Oklaunion Power Station.

2007 Compared to 2006

Income Before Discontinued Operations and Extraordinary Loss from our Generation and Marketing segment increased from $12 million in 2006 to $67 million in 2007. The increase primarily relates to the sale in 2007 of our equity investment in Sweeny and related contracts which resulted in income. 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.

All Other

2008 Compared to 2007

Income Before Discontinued Operations and Extraordinary Loss from All Other increased to $133 million in 2008 from a $15 million loss in 2007. In 2008, we had after-tax income of $164 million from a litigation settlement of a purchase power and sale agreement with TEM. The settlement was recorded as a pretax credit to Asset Impairments and Other Related Charges of $255 million in the accompanying Consolidated Statements of Income.

2007 Compared to 2006

Loss Before Discontinued Operations and Extraordinary Loss 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.

AEP System Income Taxes

2008 Compared to 2007

Income Tax Expense increased $126 million between 2007 and 2008 primarily due to an increase in pretax book income.

2007 Compared to 2006

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

FINANCIAL CONDITION

We measure our financial condition by the strength of our balance sheet and the liquidity provided by our cash flows. During 2008, we maintained our strong financial condition as reflected by our issuance of $2.8 billion of long-term debt primarily to fund our construction program, refinance auction-rate debt and retire debt maturities.

Debt and Equity Capitalization

	December 31,			
	2008		2007	
	($ in millions)			
Long-term Debt, including amounts due within one year	$ 15,983	55.7%	$ 14,994	58.1%
Short-term Debt	1,976	6.9	660	2.6
Total Debt	17,959	62.6	15,654	60.7
Common Equity	10,693	37.2	10,079	39.1
Preferred Stock	61	0.2	61	0.2
Total Debt and Equity Capitalization	$ 28,713	100.0%	$ 25,794	100.0%

Our ratio of debt to total capital increased from 60.7% to 62.6% in 2008 due to our issuance of debt to fund construction and our strategy to deal with the credit situation by drawing $2 billion from our credit facilities.

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 long-term debt, sale-leaseback or leasing agreements and common stock.

Capital Markets

In 2008, the domestic and world economies experienced significant slowdowns. Concurrently, the financial markets have become increasingly unstable and constrained at both a global and domestic level. This systemic marketplace distress is impacting our access to capital, liquidity and cost of capital. The uncertainties in the capital markets could have significant implications since we rely on continuing access to capital to fund operations and capital expenditures.

We believe we have adequate liquidity through 2009 under our existing credit facilities. However, the current credit markets are constraining our ability to issue new debt, including commercial paper, and refinance existing debt. Approximately $300 million (excluding payments due for securitization bonds which we recover from ratepayers) of our $16 billion of long-term debt as of December 31, 2008 will mature in 2009. We intend to refinance these maturities. To support our operations, we have $3.9 billion in aggregate credit facility commitments. These commitments include 27 different banks with no one bank having more than 10% of our total bank commitments. In 2008, we borrowed $2 billion under our credit agreements during this period of market disruptions and renewed our sale of receivables agreement with a $700 million commitment.

During the fourth quarter of 2008, we issued new debt including $129 million of pollution control bonds at 7.125% and an $85 million 3-year variable term loan at 3.2% as of December 31, 2008. In 2009, I&M issued $475 million of 7% senior notes due 2019 and PSO issued $34 million of 5.25% Pollution Control Bonds due 2014. However, our ability to issue debt continues to be constrained as a result of current market conditions.

We cannot predict the length of time the current credit situation will continue or its impact on future operations and our ability to issue debt at reasonable interest rates. When market conditions improve, we plan to repay a portion of the amounts drawn under the credit facilities and issue commercial paper and long-term debt. If there is not an improvement in access to capital, we believe that we have adequate liquidity to support our planned business operations and construction program through 2009.

In the first quarter of 2008, bond insurers' exposure in connection with developments in the subprime credit market resulted in increasing occurrences of failed auctions for tax-exempt long-term debt sold at auction rates. Consequently, we chose to exit the auction-rate debt market and reduced our outstanding auction-rate securities from the December 2007 balance by $1.2 billion. As of December 31, 2008, $272 million of our auction-rate tax-exempt long-term debt (rates range between 2.034% and 13%) remained outstanding with rates reset every 35 days. 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.

As of December 31, 2008, approximately $218 million of the $272 million of outstanding auction-rate debt relates to a lease structure with JMG that we are unable to refinance without JMG's consent. The rates for this debt range from 6.388% to 13%. The initial term for the JMG lease structure matures on March 31, 2010. We are evaluating whether to terminate this facility prior to maturity. Termination of this facility requires approval from the PUCO.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. At December 31, 2008, our available liquidity was approximately $1.9 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$ 1,500	March 2011
Revolving Credit Facility	1,454 (a)	April 2012
Revolving Credit Facility	627 (a)	April 2011
Revolving Credit Facility	338 (a)	April 2009
Total	3,919	
Cash and Cash Equivalents	411	
Total Liquidity Sources	4,330	
Less: Cash Drawn on Credit Facilities	1,969	
Letters of Credit Issued	434	
Net Available Liquidity	$ 1,927	

(a) Reduced by Lehman Brothers Holdings Inc.'s commitment amount of $81 million following its bankruptcy.

The revolving credit facilities for commercial paper backup were structured as two $1.5 billion credit facilities which were reduced by Lehman Brothers Holdings Inc.'s commitment amount of $46 million following its bankruptcy. In March 2008, the credit facilities were amended so that $750 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, 2008, we had credit facilities totaling $3 billion to support our commercial paper program. In 2008, we borrowed $2 billion under these credit facilities at a LIBOR rate. The maximum amount of commercial paper outstanding during 2008 was $1.2 billion. The weighted-average interest rate for our commercial paper during 2008 was 3.32%. No commercial paper was outstanding at December 31, 2008 due to market conditions.

In April 2008, we entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement which were reduced by Lehman Brothers Holdings Inc.'s commitment amount of $23 million and $12 million, respectively, following its bankruptcy. Under the facilities, we may issue letters of credit. As of December 31, 2008, $372 million of letters of credit were issued under the 3-year credit agreement to support variable rate Pollution Control Bonds.

Sale of Receivables

In 2008, we renewed our sale of receivables agreement through October 2009. The sale of receivables agreement provides a commitment of $700 million from banks and commercial paper conduits to purchase receivables. We intend to extend or replace the sale of receivables agreement at maturity.

Master Lease Agreements

During 2008, GE Capital Commercial Inc. (GE) notified us that they terminated our Master Leasing Agreements. In 2010 and 2011, we will be required to purchase all equipment under the terminated leases and pay GE an amount equal to the unamortized value of all equipment then leased. We expect to enter into replacement leasing arrangements for new equipment by the end of 2009 and for the equipment affected by the termination prior to their repayment due dates in 2010 and 2011.

In December 2008, we signed two new master lease agreements with The Huntington National Bank and RBS Asset Finance, Inc. for one-year commitment periods. The new agreements allow lease terms up to 10 years with variable and fixed rate options. The initial rates for issuances under the new leases were approximately 4% fixed and 3% variable. Management believes that these leasing agreements are adequate for our 2009 leased property acquisitions.

Investments in Auction-Rate Securities

Prior to June 30, 2008, we sold all of our investment in auction-rate securities at par.

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, 2008, this contractually-defined percentage was 58.1%. Nonperformance of these covenants could result in an event of default under these credit agreements. In addition, the acceleration of certain of our subsidiaries' or our payment obligations 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. At December 31, 2008, we complied with all of the covenants contained in these credit agreements.

The revolving credit facilities do not permit the lenders to refuse a draw on any 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, 2008, 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 395 consecutive quarters. The Board of Directors declared a quarterly dividend of $0.41 per share in January 2009. Future dividends may vary depending upon our profit levels, operating cash flows and capital requirements, as well as financial and other business conditions existing at the time. We have the option to defer interest payments on $315 million of our Junior Subordinated Debentures for one or more periods of up to 10 consecutive years per period. During any period in which we defer interest payments, we may not declare or pay any dividends or distributions on, or redeem, repurchase or acquire, our common stock. We believe that these restrictions will not have a material effect on our cash flows, financial condition or limit any dividend payments in the foreseeable future.

Credit Ratings

Our current credit ratings are as follows:

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

In 2009, Moody's:

- Placed AEP on negative outlook due to concern about overall credit worthiness, pending rate cases and recessionary pressures.
- Placed OPCo, SWEPCo, TCC and TNC on review for possible downgrade due to concerns about financial metrics and pending cost and construction recoveries.
- Affirmed the stable rating outlooks for CSPCo, I&M, KPCo and PSO.
- Changed the rating outlook for APCo from negative to stable due to recent rate recoveries in Virginia and West Virginia.

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,		
	2008	2007	2006
		(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 178	$ 301	$ 401
Net Cash Flows from Operating Activities	2,576	2,388	2,732
Net Cash Flows Used for Investing Activities	(4,027)	(3,921)	(3,743)
Net Cash Flows from Financing Activities	1,684	1,410	911
Net Increase (Decrease) in Cash and Cash Equivalents	233	(123)	(100)
Cash and Cash Equivalents at End of Period	$ 411	$ 178	$ 301

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

Operating Activities

	Years Ended December 31,		
	2008	2007	2006
		(in millions)	
Net Income	$ 1,380	$ 1,089	$ 1,002
Less: Discontinued Operations, Net of Tax	(12)	(24)	(10)
Income Before Discontinued Operations	1,368	1,065	992
Depreciation and Amortization	1,483	1,513	1,467
Other	(275)	(190)	273
Net Cash Flows from Operating Activities	$ 2,576	$ 2,388	$ 2,732

Net Cash Flows from Operating Activities were $2.6 billion in 2008 consisting primarily of Income Before Discontinued Operations of $1.4 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. Net Cash Flows from Operating Activities increased in 2008 due to the TEM settlement. Under-recovered fuel costs and fuel, material and supplies inventories increased working capital requirements due to the higher cost of coal and natural gas. Deferred Income Taxes increased primarily due to the enactment of the Economic Stimulus Act which enhanced expensing provisions for certain assets placed in service in 2008 and provided for a 50% bonus depreciation provision for certain assets placed in service in 2008.

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.

Investing Activities

	Years Ended December 31,		
	2008	**2007**	**2006**
		(in millions)	
Construction Expenditures	$ (3,800)	$ (3,556)	$ (3,528)
Acquisitions of Assets	(160)	(512)	-
Proceeds from Sales of Assets	90	222	186
Other	(157)	(75)	(401)
Net Cash Flows Used for Investing Activities	$ (4,027)	$ (3,921)	$ (3,743)

Net Cash Flows Used for Investing Activities were $4 billion in 2008 primarily due to Construction Expenditures for distribution, environmental and new generation investment.

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.

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

We forecast approximately $2.6 billion of construction expenditures for 2009. 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 net income and financing activities.

Financing Activities

	Years Ended December 31,		
	2008	**2007**	**2006**
		(in millions)	
Issuance of Common Stock	$ 159	$ 144	$ 99
Issuance/Retirement of Debt, Net	2,266	1,902	1,420
Dividends Paid on Common Stock	(660)	(630)	(591)
Other	(81)	(6)	(17)
Net Cash Flows from Financing Activities	$ 1,684	$ 1,410	$ 911

Net Cash Flows from Financing Activities were $1.7 billion in 2008 primarily due to the borrowing under our credit facility to provide liquidity in the current credit market. We paid common stock dividends of $660 million.

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.

The following financing activities occurred during 2008:

Common Stock:

- During 2008, we issued 4,394,552 shares of common stock under our incentive compensation, employee savings and dividend reinvestment plans and received net proceeds of $159 million.
- During 2008, we contributed 1,250,000 shares of common stock held in the treasury to the AEP Foundation.

Debt:

- During 2008, we issued approximately $2.8 billion of long-term debt, including $1.6 billion of senior notes at a weighted average interest rate of 6.43%, $809 million of pollution control revenue bonds ($367 million at variable rates and $442 million at a weighted average fixed interest rate of 5.67%), a variable rate $85 million 3-year term loan (3.2% at December 31, 2008) and $315 million of junior subordinated debentures at 8.75%. The proceeds from these issuances were used to fund long-term debt maturities and optional redemptions and construction programs. We also remarketed $182 million of pollution control revenue bonds with new weighted average interest rates of 4.97% under the terms of their original issuance documents.
- During 2008, we entered into $150 million of interest rate derivatives and settled $420 million of such transactions. The settlements resulted in a net cash expenditure of $11 million. As of December 31, 2008, we had in place interest rate derivatives designated as cash flow hedges with a notional amount of $100 million in order to hedge risk exposure of variable interest rate debt.
- At December 31, 2008, we had credit facilities totaling $3 billion to support our commercial paper program and short-term borrowing. As of December 31, 2008, we had $2 billion borrowed under the credit facilities and no commercial paper outstanding due to the current credit market. For the corporate borrowing program, the maximum amount of commercial paper outstanding during the year was $1.2 billion in May 2008 and the weighted average interest rate of commercial paper outstanding during the year was 3.32%.

In 2009:

- We issued the following debt:
  - In January 2009, I&M issued $475 million of 7% Senior Notes due 2019.
  - In February 2009, PSO issued $34 million of 5.25% Pollution Control Bonds due 2014.
- We retired the following debt:
  - In January 2009, TCC retired $81 million of its outstanding Securitization Bonds.
- Our capital investment plans for 2009 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 a portion of 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 2009. We intend to extend or replace the sale of receivables agreement. The sale of receivables agreement provides commitments of $700 million to purchase receivables from AEP Credit. At December 31, 2008, $650 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. For the remaining receivables left unsold to the commercial paper conduits and banks, AEP Credit maintains an interest in the receivables 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 billion as of December 31, 2008.

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 13. 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 initial lease term was five years with three, consecutive five-year renewal periods for a maximum lease term of twenty years. We intend to maintain the lease for the full lease term of twenty years, via the renewal options. The lease is accounted for as an operating lease. The future minimum lease obligation is $43 million for the remaining railcars as of December 31, 2008. Under a 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, 2008, the maximum potential loss was approximately $25 million ($17 million, net of tax) assuming the fair market value of the equipment is zero at the end of the current five-year 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 cash 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, 2008:

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)	$ 1,976	$ -	$ -	$ -	$ 1,976
Interest on Fixed Rate Portion of Long-term Debt (b)	895	1,604	1,480	9,731	13,710
Fixed Rate Portion of Long-term Debt (c)	362	2,260	1,898	10,403	14,923
Variable Rate Portion of Long-term Debt (d)	85	400	-	639	1,124
Capital Lease Obligations (e)	94	119	46	149	408
Noncancelable Operating Leases (e)	336	771	437	1,671	3,215
Fuel Purchase Contracts (f)	3,788	4,832	2,590	7,362	18,572
Energy and Capacity Purchase Contracts (g)	51	73	40	268	432
Construction Contracts for Capital Assets (h)	661	993	613	-	2,267
Total	$ 8,248	$ 11,052	$ 7,104	$ 30,223	$ 56,627

(a) Represents principal only excluding interest.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2008 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) See Note 14. Represents principal only excluding interest.
(d) See Note 14. Represents principal only excluding interest. Variable rate debt had interest rates that ranged between 0.75% and 13.0% at December 31, 2008.
(e) See Note 13.
(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 obligations for energy and capacity purchase contracts.
(h) Represents only capital assets that are contractual obligations.

Our FIN 48 liabilities of $87 million are not included above because we cannot reasonably estimate the cash flows by period.

Our minimum pension funding requirements are not included in the above table. As of December 31, 2008, the decline in pension asset values will not require us to make a contribution in 2009. We currently estimate that we will need to make minimum contributions to our pension plan of $365 million in 2010 and $258 million in 2011. However, estimates may vary significantly based on market returns, changes in actuarial assumptions and other factors.

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, 2008, 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)	$ 433	$ 1	$ -	$ -	$ 434
Guarantees of the Performance of Outside Parties (b)	-	-	-	65	65
Guarantees of Our Performance (c)	790	1,082	20	27	1,919
Total Commercial Commitments	$ 1,223	$ 1,083	$ 20	$ 92	$ 2,418

(a) We enter into standby letters of credit. These letters of credit cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves. As the Parent, we issued all of these letters of credit in our ordinary course of business on behalf of our subsidiaries. The maximum future payments of these letters of credit are $434 million with maturities ranging from March 2009 to March 2010. 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. See "Letters of Credit" section of Note 6.

(b) See "Guarantees of Third-Party Obligations" section of Note 6.

(c) We issued performance guarantees and indemnifications for energy trading and various sale agreements.

JOINT VENTURE INITIATIVES

AEP is currently participating in the following transmission initiatives:

Project Name	Location	Projected Completion Date	Owners (Ownership %)	Total Estimated Project Costs at Completion	AEP's Equity Method Investment at December 31, 2008	Approved Return on Equity
				(in thousands)		
ETT	Texas (ERCOT)	2017	MEHC (50%) AEP (50%)	$ 1,300,000 (a)	$ 15,445	9.96%
PATH (b)	Ohio/West Virginia	2013	Allegheny Energy (50%) AEP (50%)	1,800,000 (c)	6,463	14.3%
Tallgrass	Oklahoma	2013	OGE Energy (50%) ETA (50%) (d)	500,000	109	12.8%
Prairie Wind	Kansas	2013	Westar Energy (50%) ETA (50%) (d)	600,000	31	12.8%
Pioneer	Indiana	2015	Duke Energy (50%) AEP (50%)	1,000,000	-	(e)

(a) In addition to ETT's current total estimated project costs of $1.3 billion, ETT plans to invest in additional transmission projects in ERCOT over the next several years. Future projects will be evaluated on a case-by-case basis. See "ETT" section of Note 4.

(b) In September 2007, AEP and Allegheny Energy Inc. 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.

(c) PATH consists of the "Ohio Series," the "West Virginia Series (PATH-WV)," both owned equally by Allegheny Energy and AEP and the "Allegheny Series" which is 100% owned by Allegheny Energy. The total project is estimated to cost approximately $1.8 billion. AEP's estimated share of the project cost is approximately $600 million.

(d) ETA is a 50/50 joint venture with MidAmerican Energy Holdings Company (MEHC) and AEP. ETA will be utilized as a vehicle to invest in selected transmission projects located in North America, outside of ERCOT. AEP owns 25% of Tallgrass and Prairie Wind through its ownership interest in ETA.

(e) Currently seeking rate approval from the FERC.

Electric Transmission Texas, LLC (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. We do not consolidate ETT for financial reporting purposes. Our equity investment in ETT is included in Deferred Charges and Other on our Consolidated Balance Sheets. We provide services to ETT through service agreements. ETT plans to invest in additional transmission projects in ERCOT over the next several years.

In September 2008, ETT and a group of other Texas transmission providers filed a comprehensive plan with the PUCT for completion of the Competitive Renewable Energy Zone (CREZ) initiative. The CREZ initiative is the development of 2,400 miles of new transmission lines to transport electricity from 18,000 megawatts of planned wind farm capacity in west Texas to rapidly growing cities in eastern Texas. In January 2009, the PUCT announced its decision to authorize ETT to construct CREZ related projects. ETT has estimated that the PUCT's decision authorizes ETT to construct $750 million to $850 million of new transmission assets. This estimated amount is included in ETT's current $1.3 billion of projected transmission project costs.

In October 2008, the Travis County District Court ruled that the PUCT exceeded its authority by approving ETT's application as a stand alone transmission utility without a service area under the wrong section of the statute. Management believes the ruling is incorrect. See "ETT" section of Note 4. Management cannot predict the outcome of this proceeding.

Electric Transmission America, LLC (Utilities Operations Segment)

In September 2007, we and MEHC formed Electric Transmission America, LLC (ETA) to pursue transmission opportunities located in North America, outside of ERCOT. We hold a 50% equity ownership interest in ETA. We do not consolidate ETA for financial reporting purposes. Our equity investment in ETA is included in Deferred Charges and Other on our Consolidated Balance Sheets.

Potomac-Appalachian Transmission Highline (Utility Operations Segment)

In September 2007, we 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. We will equally share the ownership and management of the West Virginia facilities (PATH-WV) and the Ohio facilities (PATH-OH) within PATH with AYE; other facilities within PATH are owned 100% by AYE. We do not consolidate PATH-WV for financial reporting purposes. Our equity investment in PATH-WV is included in Deferred Charges and Other on our Consolidated Balance Sheets. We and AYE provide services to the PATH companies through service agreements.

In December 2007, PATH-WV filed an application with the FERC for approval of a transmission formula rate to recover its cost of providing transmission service, including costs incurred prior to the formula rates going into effect. PATH-WV requested an incentive return on equity of 14.3% and the inclusion of CWIP in rate base. In February 2008, the FERC approved PATH-WV's request except for the cost of service formula and formula rate implementation protocols and ordered that the formula rates be implemented March 1, 2008, subject to true-up. Motions for rehearing were filed by intervening parties in March 2008. Management cannot predict the outcome of these motions.

SIGNIFICANT FACTORS

Ohio Electric Security Plan Filings

In April 2008, the Ohio legislature passed Senate Bill 221, which amended the restructuring law effective July 31, 2008 and required electric utilities to adjust their rates by filing an Electric Security Plan (ESP). Electric utilities could include a fuel cost recovery mechanism (FCR) in their ESP filing. Electric utilities also had an option to file a Market Rate Offer (MRO) for generation pricing. An MRO, from the date of its commencement, would have transitioned CSPCo and OPCo to full market rates no sooner than six years and no later than ten years after the PUCO approves an MRO. The PUCO has the authority to approve and/or modify each utility's ESP request. The PUCO is required to approve an ESP if, in the aggregate, the ESP is more favorable to ratepayers than an MRO. Both alternatives involve a "significantly excessive earnings" (SEET) test based on what public companies, including other utilities with similar risk profiles, earn on equity.

In July 2008, within the parameters of the ESPs, CSPCo and OPCo filed with the PUCO to establish rates for 2009 through 2011. CSPCo and OPCo did not file an optional MRO. CSPCo's and OPCo's ESP filings requested an annual rate increase for 2009 through 2011 that would not exceed approximately 15% per year. A significant portion of the requested ESP increases resulted from the implementation of a FCR that primarily includes fuel costs, purchased power costs, consumables such as urea, other variable production costs and gains and losses on sales of emission allowances. The FCR is proposed to be phased into customer bills over the three-year period from 2009 through 2011 and recovered with a weighted average cost of capital carrying cost deferral over seven years from 2012 through 2018. If the ESPs are approved as filed, effective with the implementation of the ESPs, CSPCo and OPCo will defer fuel cost over/under-recoveries and related carrying costs, including amounts unrecovered through the phase in period, for future recovery.

In addition to the FCR, the requested ESP increases would also recover incremental carrying costs associated with environmental costs, Provider of Last Resort (POLR) charges to compensate for the risk of customers changing electric suppliers, automatic increases for distribution reliability costs and for unexpected non-fuel generation costs. The filings also include recovery for programs for smart metering initiatives, economic development, mandated energy efficiency, renewable resources and peak demand reduction programs.

Within the ESP requests, CSPCo and OPCo would also recover existing regulatory assets of $47 million and $39 million, respectively, for customer choice implementation and line extension carrying costs incurred through December 2008. In addition, CSPCo and OPCo would recover related unrecorded equity carrying costs of $31 million and $23 million, respectively, through December 2008. The PUCO had previously issued orders allowing deferral of these costs. Such costs would be recovered over an 8-year period beginning January 2011. If the PUCO does not approve recovery of these regulatory assets in this or some future proceeding, it would have an adverse effect on future net income and cash flows.

Hearings were held in November and December 2008. Many intervenors filed opposing testimony. CSPCo and OPCo requested retroactive application of the new rates, including the FCR, back to the start of the January 2009 billing cycle upon approval of the ESPs. The RSP rates were effective for the years ended December 31, 2006, 2007 and 2008 under which CSPCo and OPCo had three annual generation rate increases of 3% and 7%, respectively. The RSP also allowed additional annual generation rate increases of up to an average of 4% per year to recover new governmentally-mandated costs. In January 2009, CSPCo and OPCo filed an application requesting the PUCO to authorize deferred fuel accounting beginning January 1, 2009. A motion to dismiss the application has been filed by Ohio Partners for Affordable Energy, while the Ohio Consumers' Counsel has filed comments opposing the application. The PUCO ordered that CSPCo and OPCo continue using their current RSP rates until the PUCO issues a ruling on the ESPs or the end of the March 2009 billing cycle, whichever comes first. Management is unable to predict the financial statement impact of the restructuring legislation until the PUCO acts on specific proposals made by CSPCo and OPCo in their ESPs. CSPCo and OPCo anticipate a final order from the PUCO during the first quarter of 2009.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, likely caused by blade failure, which resulted in a fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. The turbine rotors that caused the vibration were installed in 2006 and are within the vendor's warranty period. The warranty provides for the repair or replacement of the turbine rotors if the damage was caused by a defect in materials or workmanship. I&M is working with its insurance company, Nuclear Electric Insurance Limited (NEIL), and its turbine vendor, Siemens, to evaluate the extent of the damage resulting from the incident and the costs to return the unit to service. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately $330 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance and the regulatory process. Our current analysis indicates that with successful repairs and timely parts deliveries, Unit 1 could resume operations as early as September 2009 at reduced power. If the rotors cannot be repaired, replacement of parts will extend the outage into 2010.

I&M maintains property insurance through NEIL with a $1 million deductible. I&M also maintains a separate accidental outage policy with NEIL whereby, after a 12-week deductible period, I&M is entitled to weekly payments of $3.5 million for the first 52 weeks following the deductible period. After the initial 52 weeks of indemnity, the policy pays $2.8 million per week for up to an additional 110 weeks. In January 2009, I&M filed to provide to customers a portion of the accidental outage insurance proceeds expected during the fuel cost forecast period of April through September 2009. If the ultimate costs of the incident are not covered by warranty, insurance or through the regulatory process or if the unit is not returned to service in a reasonable period of time, it could have an adverse impact on net income, cash flows and financial condition.

Texas Restructuring Appeals

Pursuant to PUCT orders, TCC securitized its net recoverable stranded generation costs of $2.5 billion and is recovering the principal and interest on the securitization bonds through the end of 2020. TCC refunded its net other true-up regulatory liabilities of $375 million from October 2006 through June 2008 via a CTC credit rate rider. Although earnings were not affected by this CTC refund, cash flow was adversely impacted for 2008, 2007 and 2006 by $75 million, $238 million and $69 million, respectively. 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 orders seeking to further reduce TCC's true-up recoveries.

In March 2007, the Texas District Court judge hearing the appeals 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 and remanded this matter to the PUCT for further consideration. The District Court judge also determined that the PUCT improperly reduced TCC's net stranded plant costs for commercial unreasonableness.

TCC, the PUCT and intervenors appealed the District Court decision to the Texas Court of Appeals. In May 2008, the Texas Court of Appeals affirmed the District Court decision in all but two major respects. It reversed the District Court's unfavorable decision which found that the PUCT erred by applying an invalid rule to determine the carrying cost rate. It also determined that the PUCT erred by not reducing stranded costs by the "excess earnings" that had already been refunded to affiliated retail electric providers. Management does not believe that TCC will be adversely affected by the Court of Appeals ruling on excess earning based upon the reasons discussed in the "TCC Excess Earnings" section within "Texas Rate Matters". The favorable commercial unreasonableness judgment entered by the District Court was not reversed. The Texas Court of Appeals denied intervenors' motion for rehearing. In May 2008, TCC, the PUCT and intervenors filed petitions for review with the Texas Supreme Court. Review is discretionary and the Texas Supreme Court has not determined if it will grant review.

TNC received its final true-up order in May 2005 that resulted in refunds via a CTC which have been completed. Appeals brought by intervenors and TNC of the final true-up order remain pending in state court.

Management cannot predict the outcome of these court proceedings and PUCT remand decisions. If TCC and/or TNC ultimately succeed in its appeals, it could have a material favorable effect on future net income, cash flows and financial condition. If municipal customers and other intervenors succeed in their appeals, it could have a substantial adverse effect on future net income, cash flows and financial condition.

New Generation

In 2008, AEP completed or is in various stages of construction of the following generation facilities:

Operating Company	Project Name		Location	Total Projected Cost (a)	CWIP (b)	Fuel Type	Plant Type	Nominal MW Capacity	Commercial Operation Date (Projected)
				(in millions)	(in millions)				
PSO	Southwestern	(c)	Oklahoma	$ 56	$ -	Gas	Simple-cycle	150	2008
PSO	Riverside	(d)	Oklahoma	58	-	Gas	Simple-cycle	150	2008
AEGCo	Dresden	(e)	Ohio	310	179	Gas	Combined-cycle	580	2013
SWEPCo	Stall		Louisiana	384	252	Gas	Combined-cycle	500	2010
SWEPCo	Turk	(f)	Arkansas	1,628(f)	510	Coal	Ultra-supercritical	600(f)	2012
APCo	Mountaineer	(g)	West Virginia	(g)		Coal	IGCC	629	(g)
CSPCo/OPCo	Great Bend	(g)	Ohio	(g)		Coal	IGCC	629	(g)

(a) Amount excludes AFUDC.
(b) Amount includes AFUDC.
(c) Southwestern Units were placed in service on February 29, 2008.
(d) The final Riverside Unit was placed in service on June 15, 2008.
(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 440 MW, totaling $1.2 billion in capital investment. The increase in the cost estimate disclosed in the 2007 Annual Report relates to cost escalations due to the delay in receipt of permits and approvals. See "Turk Plant" section below.
(g) Construction of IGCC plants are pending regulatory approvals. See "IGCC Plants" section below.

Turk Plant

In November 2007, the APSC granted approval to build the Turk Plant. Certain landowners filed a notice of appeal to the Arkansas State Court of Appeals. In March 2008, the LPSC approved the application to construct the Turk Plant.

In August 2008, the PUCT issued an order approving the Turk Plant with the following four conditions: (a) the capping of capital costs for the Turk Plant at the previously estimated $1.522 billion projected construction cost, excluding AFUDC, (b) capping CO_2 emission costs at $28 per ton through the year 2030, (c) holding Texas ratepayers financially harmless from any adverse impact related to the Turk Plant not being fully subscribed to by other utilities or wholesale customers and (d) providing the PUCT all updates, studies, reviews, reports and analyses as previously required under the Louisiana and Arkansas orders. In October 2008, SWEPCo appealed the PUCT's order regarding the two cost cap restrictions. If the cost cap restrictions are upheld and construction or emissions costs exceed the restrictions, it could have a material adverse impact on future net income and cash flows. In October 2008, an intervenor filed an appeal contending that the PUCT's grant of a conditional Certificate of Public Convenience and Necessity for the Turk Plant was not necessary to serve retail customers.

A request to stop pre-construction activities at the site was filed in federal court by Arkansas landowners. In July 2008, the federal court denied the request and the Arkansas landowners appealed the denial to the U.S. Court of Appeals.

In November 2008, SWEPCo received the air permit approval from the Arkansas Department of Environmental Quality and commenced construction. In December 2008, Arkansas landowners filed an appeal with the Arkansas Pollution Control and Ecology Commission (APCEC) which caused construction of the Turk Plant to halt until the APCEC took further action. In December 2008, SWEPCo filed a request with the APCEC to continue construction of the Turk Plant and the APCEC ruled to allow construction to continue while an appeal of the Turk Plant's permit is heard. SWEPCo is also working with the U.S. Army Corps of Engineers for the approval of a wetlands and stream impact permit.

In January 2008 and July 2008, SWEPCo filed Certificate of Environmental Compatibility and Public Need (CECPN) applications with the APSC to construct transmission lines necessary for service from the Turk Plant. Several landowners filed for intervention status and one landowner also contended he should be permitted to re-litigate Turk Plant issues, including the need for the generation. The APSC granted their intervention but denied the request to re-litigate the Turk Plant issues. In June 2008, the landowner filed an appeal to the Arkansas State Court of Appeals requesting to re-litigate Turk Plant issues. SWEPCo responded and the appeal was dismissed. In January 2009, the APSC approved the CECPN applications.

The Arkansas Governor's Commission on Global Warming issued its final report to the Governor in October 2008. The Commission was established to set a global warming pollution reduction goal together with a strategic plan for implementation in Arkansas. The Commission's final report included a recommendation that the Turk Plant employ post combustion carbon capture and storage measures as soon as it starts operating. If legislation is passed as a result of the findings in the Commission's report, it could impact SWEPCo's proposal to build the Turk Plant.

If SWEPCo does not receive appropriate authorizations and permits 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 paid costs. If that occurred, SWEPCo would seek recovery of its capitalized costs including any cancellation fees and joint owner reimbursements. As of December 31, 2008, SWEPCo has capitalized approximately $510 million of expenditures (including AFUDC) and has significant contractual construction commitments for an additional $727 million. As of December 31, 2008, if the plant had been cancelled, SWEPCo would have incurred cancellation fees of $61 million. If the Turk Plant does not receive all necessary approvals on reasonable terms and SWEPCo cannot recover its capitalized costs, including any cancellation fees, it would have an adverse effect on future net income, cash flows and possibly financial condition.

IGCC Plants

The construction of the West Virginia and Ohio IGCC plants are pending regulatory approvals. In April 2008, the Virginia SCC issued an order denying APCo's request to recover initial costs associated with a proposed IGCC plant in West Virginia. In July 2008, the WVPSC issued a notice seeking comments from parties on how the WVPSC should proceed regarding its earlier approval of the IGCC plant. Comments were filed by various parties, including APCo, but the WVPSC has not taken any action. In July 2008, the IRS allocated $134 million in future tax credits to APCo for the planned IGCC plant contingent upon the commencement of construction, qualifying expenses being incurred and certification of the IGCC plant prior to July 2010. Through December 31, 2008, APCo deferred for future recovery preconstruction IGCC costs of $20 million. If the West Virginia IGCC plant is cancelled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs. If the plant is cancelled and if the deferred costs are not recoverable, it would have an adverse effect on future net income and cash flows.

In Ohio, neither CSPCo nor OPCo are engaged in a continuous course of construction on the IGCC plant. However, CSPCo and OPCo continue to pursue the ultimate construction of the IGCC plant. In September 2008, the Ohio Consumers' Counsel filed a motion with the PUCO requesting all Phase 1 cost recoveries be refunded to Ohio ratepayers with interest. CSPCo and OPCo filed a response with the PUCO that argued the Ohio Consumers' Counsel's motion was without legal merit and contrary to past precedent. If CSPCo and OPCo were required to refund some or all of the $24 million collected for IGCC pre-construction costs and those costs were not recoverable in another jurisdiction in connection with the construction of an IGCC plant, it would have an adverse effect on future net income and cash flows.

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). We merged the Qualified Plans at December 31, 2008. 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 and assumed rate of return on the Plans' assets:

	Years Ended December 31, 2008	2007	2006
Net Periodic Benefit Cost		(in millions)	
Pension Plans	$ 51	$ 50	$ 71
Postretirement Plans	80	81	96
Assumed Rate of Return			
Pension Plans	8.00%	8.50%	8.50%
Postretirement Plans	8.00%	8.00%	8.00%

The net periodic benefit cost is calculated based upon a number of actuarial assumptions, including expected long-term rates on return on the Plans' assets. In developing the expected long-term rate of return assumption for 2009, 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 2008, of approximately 3%. We anticipate that the investment managers we employ for the Plans will generate future returns averaging 8.00% for the Pension Plan and 7.75% for the Postretirement Plans.

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 Plans			Other Postretirement Benefit Plans		
	2008 Actual Asset Allocation	2009 Target Asset Allocation	Assumed/ Expected Long-term Rate of Return	2008 Actual Asset Allocation	2009 Target Asset Allocation	Assumed/ Expected Long-term Rate of Return
Equity	47%	55%	9.5%	53%	65%	8.8%
Real Estate	6%	5%	7.5%	-%	-%	-%
Debt Securities	42%	39%	6.0%	43%	34%	5.8%
Cash and Cash Equivalents	5%	1%	3.5%	4%	1%	2.7%
Total	100%	100%		100%	100%	

	2009 Pension	2009 Other Postretirement Benefit Plans
Overall Expected Return (weighted average)	8.00%	7.75%

Global capital markets experienced extreme volatility in 2008. The value of investments in our pension and OPEB trusts declined substantially due to decreases in domestic and international equity markets. Although the asset values are lower, this decline has not affected the funds' ability to make their required payments.

We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation. We believe that 8% for the Pension Plans and 7.75% for the Postretirement Plans are reasonable long-term rates of return on the Plans' assets despite the recent market volatility. The Pension Plans' assets had an actual (loss) gain of (24.1)% and 9.2% for the years ended December 31, 2008 and 2007, respectively. The Postretirement Plans' assets had an actual (loss) gain of (24.7)% and 8.6% for the years ended December 31, 2008 and 2007, 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, 2008, we had cumulative losses of approximately $1 billion that remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial losses will result in increases in the future pension costs depending on several factors, including whether such losses 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, 2008 under this method was 6.00% for the Pension Plans and 6.10% 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 $92 million, $145 million and $152 million in 2009, 2010 and 2011, respectively. Based on an expected rate of return on the OPEB plans' assets of 7.75%, a discount rate of 6.10% and various other assumptions, we estimate Postretirement Plan costs will approximate $148 million, $140 million and $121 million in 2009, 2010 and 2011, 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 decreased substantially to $3.2 billion at December 31, 2008 from $4.5 billion at December 31, 2007 primarily due to investment losses. The Qualified Plans paid $289 million in benefits to plan participants during 2008 (nonqualified plans paid $7 million in benefits). The value of our Postretirement Plans' assets decreased substantially to $1 billion at December 31, 2008 from $1.4 billion at December 31, 2007 primarily due to investment losses. The Postretirement Plans paid $120 million in benefits to plan participants during 2008.

Investments in trusts are stated at fair market value. We utilize our trustee's external pricing service to measure the market value of the underlying investments. Our investment managers review and validate the prices utilized to determine fair market value. We also perform our own valuation testing to validate the market values of the actively traded securities. We receive audit reports of our trustee's operating controls and valuation processes. Where possible, quoted prices on actively traded exchanges are used to determine value. Debt holdings that are not actively traded may be valued based on the observable pricing of comparable securities. Investments in commingled funds are generally not actively traded and are priced at a Net Asset Value (NAV) which is based on the underlying holdings of the funds. These holdings are typically actively traded equities or debt securities that may be valued in a manner similar to direct debt investments. Trust assets as of December 31, 2008 include approximately $244 million of real estate and private equity investments in the pension fund that are valued based on methods requiring judgment.

Our Qualified Plans were underfunded as of December 31, 2008. No contribution to the Qualified Plans is required under ERISA in 2009. Minimum contributions to the Qualified Plans of $365 million in 2010 and $258 million in 2011 are currently projected under ERISA and may vary significantly based on future market returns, changes in actuarial assumptions and other factors. Our nonqualified pension plans are unfunded, and are therefore considered underfunded for accounting purposes. For the nonqualified pension plans, the accumulated benefit obligation exceeded plan assets by $80 million and $77 million at December 31, 2008 and 2007, respectively.

Certain pension plans we sponsor contain a cash balance benefit feature. In 2008, the IRS issued Determination Letters confirming the tax exempt status of these plans including the cash balance benefit feature.

The Worker, Retiree and Employer Recovery Act of 2008 did not materially impact our plans.

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.

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 utilize our trustee's external pricing service to measure the market value of the underlying investments held in these trusts. Our investment managers review and validate the prices utilized to determine fair market value. We also perform our own valuation testing to validate the market values of the actively traded securities. We receive audit reports of our trustee's operating controls and valuation processes.

Litigation

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what their eventual outcome will be, or what the timing of the amount of any loss, fine or penalty may be. We assess the probability of loss for each contingency and accrue a liability for cases that have a probable likelihood of loss 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 net income.

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 2007, we settled this litigation by a consent decree with the Federal EPA, the DOJ, the states and the special interest groups. Under the consent decree, we agreed to annual SO_2 and NO_x emission caps for sixteen coal-fired power plants located in Indiana, Kentucky, Ohio, Virginia and West Virginia. We agreed to install FGD equipment at Big Sandy and at Muskingum River Plants no later than the end of 2015 and SCR and FGD emissions control equipment at Rockport Plant no later than the end of 2017 and 2019 for Unit 1 and Unit 2, respectively. We also agreed to install selective non-catalytic reduction, a NO_x-reduction technology, at Clinch River Plant in 2009.

CSPCo jointly-owns Beckjord and Stuart Stations with Duke Energy Ohio, Inc. and Dayton Power and Light Company. A jury trial returned a verdict of no liability at the jointly-owned Beckjord unit. In December 2008, however, the court ordered a new trial in the Beckjord case. In October 2008, the court approved a settlement in a citizen suit action filed by Sierra Club against the jointly-owned units at Stuart Station. Under the settlement, the joint-owners of Stuart Station agreed to certain emission targets related to NO_x, SO_2 and PM. The joint-owners also agreed to make energy efficiency and renewable energy commitments that are conditioned on PUCO approval for recovery of costs. The joint-owners also agreed to forfeit 5,500 SO_2 allowances and provide $300 thousand to a third party organization to establish a solar water heater rebate program.

Environmental Matters

We are implementing a substantial capital investment program and incurring additional operational costs to comply with environmental control requirements. The sources of these requirements include:

- Requirements under the CAA to reduce emissions of SO_2, NO_x and PM 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 SNF and future decommissioning of our nuclear units. We are also engaged in the development of possible future requirements to reduce CO_2 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 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. In 2008, the Federal EPA issued revised NAAQS for both ozone and $PM_{2.5}$. These new standards could increase the levels of SO_2 and NO_x reductions required from our facilities. The Federal EPA also established a lower standard for lead, and conducts periodic reviews for additional criteria pollutants including SO_2 and NO_x.

In 2005, the Federal EPA issued the Clean Air Interstate Rule (CAIR). It requires specific reductions in SO_2 and NO_x emissions from power plants and assists states developing new SIPs to meet the NAAQS. CAIR reduces regional emissions of SO_2 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 SO_2 by 50% by 2010, and by 65% by 2015. NO_x emissions will be subject to additional limits beginning in 2009, and will be reduced by a total of 70% from current levels by 2015. Reductions of both SO_2 and NO_x would be achieved through a cap-and-trade program. In July 2008, the D.C. Circuit Court of Appeals issued a decision that would vacate CAIR and remanded the rule to the Federal EPA. In September 2008, the Federal EPA and other parties petitioned for rehearing. In December 2008, the D.C. Circuit Court of Appeals granted the Federal EPA's petition and remanded the rule to the Federal EPA without vacatur, allowing CAIR to remain in effect while a new rulemaking is conducted. We are unable to predict how the Federal EPA will respond to the remand. 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 states may elect to seek further reductions of SO_2 and NO_x 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 SO_2 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. The Federal EPA filed a petition for review by the U.S. Supreme Court, but the new Federal EPA Administrator asked that the petition be withdrawn. We are unable to predict the outcome of this appeal or 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 SO_2 emissions from power plants. By 2000, the program established a nationwide cap on power plant SO_2 emissions of 8.9 million tons per year. The 1990 Amendments also contain requirements for power plants to reduce NOx emissions through the use of available combustion controls.

The success of the SO_2 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 currently uses the SO_2 allowances originally allocated through the Acid Rain Program as the basis for its SO_2 cap-and-trade system. We are unable to predict if or how any replacement for CAIR will utilize the SO_2 allowances from the Acid Rain Program.

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 (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 program 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 SO_2 and NO_x, some additional controls will be required. The courts upheld the final rule.

In January 2009, the Federal EPA issued a determination that 37 states (including Indiana, Ohio, Oklahoma, Texas and Virginia) failed to submit SIP's fulfilling the Regional Haze program requirements by the deadline, and commencing a 2-year period for the development of a Federal Implementation Plan (FIP) in these states. We are unable to predict if or how the remand of CAIR or the development of a FIP for certain states may affect our compliance obligations for the Regional Haze programs.

Estimated Air Quality Environmental Investments

The CAIR 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 2008, we installed SCR technology on over 11,380 MW of our eastern power plants to comply with NO_x emission requirements. We comply with SO_2 emission requirements by installing scrubbers and using alternate fuels and SO_2 allowances. We receive allowances through allocation and purchase at either the annual Federal EPA auction or in the market. Decreasing allowance allocations, our diminishing SO_2 allowance bank, increasing allowance costs, CAIR 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 9,000 MW for SO_2 control. From 2009 to 2013, we estimate total environmental investment of $3.6 billion including investment in scrubbers and other SO_2 equipment of approximately $2.6 billion. These estimates may be revised as a result of the court's decision remanding the CAIR and 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 and the NSR settlement discussed above, we expect to incur additional costs for pollution control technology retrofits between 2014 and 2020 of approximately $3.3 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 or FIPs that impose standards more stringent than CAIR; (2) additional rulemaking activities in response to the court decisions remanding the CAIR and CAMR; (3) the actual performance of the pollution control technologies installed on our units; (4) changes in costs for new pollution controls; (5) new generating technology developments; and (6) 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 net income, 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.

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.

In April 2008, the U.S. Supreme Court agreed to review decisions from the Second Circuit Court of Appeals that limit the Federal EPA's ability to weigh the retrofitting costs against environmental benefits. Management is unable to predict the outcome of this appeal.

Potential Regulation of CO_2 and Other GHG Emissions

The scientific community, led largely by the Intergovernmental Panel on Climate Change, has provided scientific evidence that human activity, and particularly the combustion of fossil fuels, has increased the levels of GHG in the atmosphere and contributed to observed changes in the global climate system. These findings have led to proposals for substantial transformation of the world's energy production and transportation systems in order to slow, and ultimately reduce, the production of CO_2 and other GHG emissions sufficiently to reduce atmospheric concentrations. Because approximately 90% of the electricity generated by the AEP System is produced by the combustion of fossil fuels, we are helping to lead the discussion nationally and internationally to find a reasonable, achievable approach and enact federal energy policy that is realistic in time frame and does not seriously harm the U.S. economy. We also are developing advanced coal technologies so that coal can continue to be the important energy resource it is today. We support the adoption of an economy-wide, cap-and-trade GHG reduction program that allows us to provide reliable, reasonably priced electricity to our customers and that fosters the international participation that is necessary to make meaningful global progress on this global challenge.

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 GHG emissions. The U.S. signed the Kyoto Protocol in 1998, but the treaty was not submitted 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. Negotiations designed to lead to a global agreement on limiting GHG emissions after the Kyoto Protocol expires have commenced, and are focused on flexible mechanisms that can address the concerns expressed by the U.S. and others regarding the global impacts of increasing emissions in developing economies, including China, Brazil, and India, and mitigating the economic impacts of GHG reductions in developed countries given current economic conditions.

Since 2005, several members of Congress have introduced bills that would regulate GHG emissions, including emissions from power plants. Congress has passed no legislation, but recent bills have received more serious consideration and some form of national legislation impacting the electric utility industry is likely to pass within the next few years. Such legislation is likely to take the form of direct regulation of GHG emissions through cap-and-trade provisions. In addition and related to climate change legislation, a national renewable portfolio standard, energy efficiency requirements for electric utilities and other measures may pass Congress in the next few years.

Several states have adopted programs that directly regulate GHG emissions from power plants, but none of these programs are currently in effect in states where we have generating facilities. Certain of our states have passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements (including Ohio, Michigan, Texas and Virginia). We are taking steps to comply with these requirements. Through our recent purchases of wind power and the existing wind assets that we have developed and our future plans, our integrated resource plan contains a 10% renewable energy target by 2020, which is nearly double the level of renewable energy requirements in effect in our states. Our plans are based on the reasonable expectation that additional federal or state requirements may be enacted that will affect our system.

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 own GHG emissions. We participate in a number of voluntary programs to monitor, mitigate and reduce GHG emissions, including the Federal EPA's Climate Leaders program, the DOE's GHG reporting program and the Chicago Climate Exchange. Through the end of 2007, we reduced our emissions by a cumulative 46 million metric tons from adjusted baseline levels in 1998-2001 as a result of these voluntary actions. Our total GHG emissions in 2007 were 155.8 million metric tons. We estimate that our 2008 emission will be approximately 155 million metric tons and our cumulative reductions will be in excess of 51 metric million tons.

We believe that climate change 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 GHG 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. We also support the Edison Electric Institute (EEI) principles for federal climate change legislation, including the consensus approach developed by EEI for the allocation of emission allowances.

President Obama has stated that he favors climate legislation that would reduce GHG emissions by 80% by 2050 and require the auctioning of all allowances. We oppose a 100% auction of GHG emission allowances, as it would substantially increase the costs of compliance on our system and increase customer rates. We support reasonable emission reduction targets that allow sufficient time for technology development and recognize that commercial scale technologies to provide substantial GHG emission reductions at new or existing electric generating units are not currently available.

While comprehensive economy-wide regulation of GHG emissions might be achieved through new legislation, several states and interest groups petitioned the Federal EPA to establish GHG emission standards under the existing requirements of the CAA. In April 2007, the U.S. Supreme Court reversed and remanded the Federal EPA's determination that it lacked the authority to regulate GHG emissions from motor vehicles for purposes of climate change under the CAA. In response to the Supreme Court's decision, the Federal EPA issued an Advance Notice of Proposed Rulemaking in July 2008 seeking comment on its analysis of the available evidence to support a finding that GHG emissions endanger human health or the environment under various provisions of the CAA, and the suitability of different provisions of the mobile source, stationary source, and permitting programs under the CAA to effectively regulate GHG emissions. We agree with the assessment of the previous EPA Administrator that the existing authorities under the CAA are not well-suited to achieving economy-wide cost-effective reductions of GHG emissions. Shortly after taking office, President Obama directed the Federal EPA to re-examine a decision denying the request by the State of California for a waiver that would allow states to establish higher fuel efficiency standards as a means of reducing GHG emissions from mobile sources. Thirteen states have taken action that would implement the California standards if the Federal EPA issues such a waiver. While this waiver, if issued, would have no immediate impact on stationary sources, should the Federal EPA choose to take other actions to regulate GHG emissions under the CAA, they could have a material impact upon the costs of operating our fossil-fueled generating plants.

In addition, certain groups have filed lawsuits alleging that emissions of CO_2 and other GHGs are a "public nuisance" and seeking injunctive relief and/or damages from small groups of coal-fired electricity generators, petroleum refiners and marketers, coal companies and others. We have been named in two pending lawsuits, which we are vigorously defending. It is not possible to predict the outcome of these lawsuits or their impact on our operations or financial condition. See "Carbon Dioxide Public Nuisance Claims" and "Alaskan Villages' Claims" sections of Note 6.

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. 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 that controls the emissions of GHG from fossil-fueled generating plants. We are advancing more efficient technologies for power generation, including ultra-super-critical technology and IGCC, as authorized by our regulatory commissions. 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 are also pursuing renewable sources of energy generation, energy efficiency measures, gridSMART load management investments and other improved transmission, distribution and energy storage methods to reduce overall GHG emissions from our operations. We will seek recovery of the costs 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 net income, 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 net income 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 incurred costs are probable of recovery through regulated rates, we record them as regulatory assets on the balance sheet. We review the probability of recovery at each balance sheet date and whenever new events occur. Examples of new events include 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 net income. 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 accordance with the applicable state commission regulatory treatment in Arkansas, Louisiana, Oklahoma and Texas, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

The change in unbilled electric utility revenues included in Revenue on our Consolidated Statements of Income were $72 million, $47 million and $(19) million for the years ended December 31, 2008, 2007 and 2006, respectively. The increases in unbilled electric revenues are primarily due to rate increases and changes in weather. Accrued unbilled revenues for the Utility Operations segment were $448 million and $376 million as of December 31, 2008 and 2007, respectively.

Assumptions and Approach Used: For each operating company, we compute 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 meter reading issues, 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, 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 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 not 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 derivatives, hedging and fair value measurements, see Note 11.

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," (SFAS 144) 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 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 7 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 7 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 8 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 Benefit Plans	
	+0.5%	**-0.5%**	**+0.5%**	**-0.5%**
	(in millions)			
Effect on December 31, 2008 Benefit Obligations				
Discount Rate	$ (182)	$ 198	$ (105)	$ 111
Compensation Increase Rate	14	(13)	3	(3)
Cash Balance Crediting Rate	50	(46)	N/A	N/A
Health Care Cost Trend Rate	N/A	N/A	96	(83)
Effect on 2008 Periodic Cost				
Discount Rate	(15)	16	(11)	12
Compensation Increase Rate	4	(4)	1	(1)
Cash Balance Crediting Rate	11	(10)	N/A	N/A
Health Care Cost Trend Rate	N/A	N/A	16	(14)
Expected Return on Plan Assets	(21)	21	(7)	7

N/A = Not Applicable

NEW ACCOUNTING PRONOUNCEMENTS

Adoption of New Accounting Pronouncements in 2008

We partially adopted SFAS 157 in 2008 and completed our adoption effective January 1, 2009. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures. The adoption of SFAS 157 had an immaterial impact on our financial statements. See "SFAS 157 Fair Value Measurements" section of Note 11 for further information.

We adopted SFAS 159 "The Fair Value Option for Financial Assets and Financial Liabilities" effective January 1, 2008. The statement permitted entities to choose to measure many financial instruments and certain other items at fair value. The standard also established presentation and disclosure requirements designed to facilitate comparison between entities that choose different measurement attributes for similar types of assets and liabilities. At adoption, we did not elect the fair value option for any assets or liabilities.

The FASB issued SFAS 162 "The Hierarchy of Generally Accepted Accounting Principles" (SFAS 162), clarifying the sources of generally accepted accounting principles in descending order of authority. The statement specifies that the reporting entity, not its auditors, is responsible for its compliance with GAAP. We adopted SFAS 162 with no impact on our financial statements.

The FASB ratified EITF 06-10 "Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements" 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 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. We adopted EITF 06-10 effective January 1, 2008 with a cumulative effect reduction of $16 million ($10 million, net of tax) to beginning retained earnings.

We adopted EITF 06-11 "Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards" (EITF 06-11) effective January 1, 2008. The rule addressed the recognition of income tax benefits of dividends on employee share-based compensation. The adoption of this standard had an immaterial impact on our financial statements.

The FASB issued FSP SFAS 133-1 and FIN 45-4 "Disclosures about Credit Derivatives and Certain Guarantees: An Amendment of FASB Statement No. 133 and FASB Interpretation No. 45; and Clarification of the Effective Date of FASB Statement No. 161." Under the SFAS 133 requirements, the seller of a credit derivative shall disclose additional information for each derivative, including credit derivatives embedded in a hybrid instrument, even if the likelihood of payment is remote. Further, the standard requires the disclosure of current payment status/performance risk of all FIN 45 guarantees. In the event an entity uses internal groupings, the entity shall disclose how those groupings are determined and used for managing risk. We adopted the standard effective December 31, 2008. The adoption of this standard had no impact on our financial statements but increased our guarantees disclosures in Note 6.

The FASB issued FSP SFAS 140-4 and FIN 46R-8 "Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interests in Variable Interest Entities" amending SFAS 140 "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities" and FIN 46R "Consolidation of Variable Interest Entities." The amendments required additional disclosure regarding transfers of financial assets and variable interest entities. We adopted the standards effective December 31, 2008. The adoption of these standards had no impact on our financial statements but increased our footnote disclosures for variable interest entities. See "Principles of Consolidation" section of Note 1.

FSP FIN 39-1 amends FIN 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 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. We adopted FIN 39-1 effective January 1, 2008.

See "Pronouncements Adopted in 2008" section of Note 2.

New Accounting Pronouncements Adopted During the First Quarter of 2009

The FASB issued SFAS 141R (revised "Business Combinations" 2007) improving financial reporting about business combinations and their effects. SFAS 141R can affect tax positions on previous acquisitions. We do not have any such tax positions that result in adjustments. We adopted SFAS 141R effective January 1, 2009. We will apply it to any future business combinations.

The FASB issued SFAS 160 "Noncontrolling Interest in Consolidated Financial Statements" (SFAS 160), modifying reporting for noncontrolling interest (minority interest) in consolidated financial statements. The statement 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. We adopted SFAS 160 retrospectively effective January 1, 2009. The adoption of this standard had an immaterial impact on our financial statements. Prior period financial statements in future filings will be comparable.

The FASB issued SFAS 161 "Disclosures about Derivative Instruments and Hedging Activities" (SFAS 161), enhancing disclosure requirements for derivative instruments and hedging activities. The standard requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. This standard will increase our disclosure requirements related to derivative instruments and hedging activities in future reports. We adopted SFAS 161 effective January 1, 2009.

The FASB ratified EITF Issue No. 08-5 "Issuer's Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement" (EITF 08-5) a consensus on liabilities with third-party credit enhancements when the liability is measured and disclosed at fair value. The consensus treats the liability and the credit enhancement as two units of accounting. We adopted EITF 08-5 effective January 1, 2009. It will be applied prospectively with the effect of initial application included as a change in fair value of the liability in the period of adoption. The adoption of this standard will impact the financial statements in the 2009 Annual Report as we report fair value of long-term debt annually.

The FASB ratified EITF Issue No. 08-6 “Equity Method Investment Accounting Considerations” (EITF 08-6), a consensus on equity method investment accounting including initial and allocated carrying values and subsequent measurements. We prospectively adopted EITF 08-6 effective January 1, 2009 with no impact on our financial statements.

We adopted FSP EITF 03-6-1 “Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities” (EITF 03-6-1) effective January 1, 2009. The rule addressed whether instruments granted in share-based payment transactions are participating securities prior to vesting and determined that the instruments need to be included in earnings allocation in computing EPS under the two-class method. The adoption of this standard had an immaterial impact on our financial statements.

The FASB issued FSP SFAS 142-3 “Determination of the Useful Life of Intangible Assets” amending factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset. We adopted the rule effective January 1, 2009. The guidance is prospectively applied to intangible assets acquired after the effective date. The standard’s disclosure requirements are applied prospectively to all intangible assets as of January 1, 2009. The adoption of this standard had no impact on our financial statements.

Pronouncements Effective in the Future

The FASB issued FSP SFAS 132R-1 “Employers’ Disclosures about Postretirement Benefit Plan Assets” providing additional disclosure guidance for pension and OPEB plan assets. The standard adds disclosure requirements including hierarchical classes for fair value and concentration of risk. This standard is effective for fiscal years ending after December 15, 2009. Management expects this standard to increase the disclosure requirements related to our benefit plans. We will adopt the standard effective for the 2009 Annual Report.

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 financial derivatives, which will gradually settle 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.

The Committee of Chief Risk Officers (CCRO) adopted disclosure standards for risk management contracts to improve clarity, understanding and consistency of information reported. 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, 2008 and the reasons for changes in our total MTM value included on our balance sheet as compared to December 31, 2007.

Reconciliation of MTM Risk Management Contracts to Consolidated Balance Sheet December 31, 2008 (in millions)

	Utility Operations	Generation and Marketing	All Other	Sub-Total MTM Risk Management Contracts	MTM of Cash Flow and Fair Value Hedges	Collateral Deposits	Total
Current Assets	$ 189	$ 20	$ 19	$ 228	$ 33	$ (5)	$ 256
Noncurrent Assets	152	188	20	360	1	(6)	355
Total Assets	341	208	39	588	34	(11)	611
Current Liabilities	(89)	(14)	(24)	(127)	(26)	19	(134)
Noncurrent Liabilities	(77)	(90)	(22)	(189)	(5)	24	(170)
Total Liabilities	(166)	(104)	(46)	(316)	(31)	43	(304)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 175	$ 104	$ (7)	$ 272	$ 3	$ 32	$ 307

MTM Risk Management Contract Net Assets (Liabilities) Year Ended December 31, 2008 (in millions)

	Utility Operations	Generation and Marketing	All Other	Total
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2007	$ 156	$ 43	$ (8)	$ 191
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(55)	11	2	(42)
Fair Value of New Contracts at Inception When Entered During the Period (a)	4	33	-	37
Net Option Premiums Paid (Received) for Unexercised or Unexpired Option Contracts Ended During the Period	-	2	-	2
Changes in Fair Value Due to Valuation Methodology Changes on Forward Contracts (b)	4	14	-	18
Changes in Fair Value Due to Market Fluctuations During the Period (c)	14	1	(1)	14
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	52	-	-	52
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2008	$ 175	$ 104	$ (7)	272
Net Cash Flow and Fair Value Hedge Contracts				3
Collateral Deposits				32
Ending Net Risk Management Assets at December 31, 2008				$ 307

(a) Reflects fair value on long-term structured contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location and delivery term.
(b) Represents the impact of applying AEP's credit risk when measuring the fair value of derivative liabilities according to SFAS 157.
(c) Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(d) "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.

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

The following table presents 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, 2008
(in millions)

	2009	2010	2011	2012	2013	After 2013 (f)	Total
Utility Operations							
Level 1 (a)	$ (9)	$ -	$ -	$ -	$ -	$ -	$ (9)
Level 2 (b)	74	36	10	1	-	-	121
Level 3 (c)	21	(2)	2	2	1	-	24
Total	86	34	12	3	1	-	136
Generation and Marketing							
Level 1 (a)	(7)	-	-	-	-	-	(7)
Level 2 (b)	9	17	16	16	16	12	86
Level 3 (c)	4	2	3	3	3	10	25
Total	6	19	19	19	19	22	104
All Other							
Level 1 (a)	-	-	-	-	-	-	-
Level 2 (b)	(5)	(4)	2	-	-	-	(7)
Level 3 (c)	-	-	-	-	-	-	-
Total	(5)	(4)	2	-	-	-	(7)
Total							
Level 1 (a)	(16)	-	-	-	-	-	(16)
Level 2 (b)	78	49	28	17	16	12	200
Level 3 (c) (d)	25	-	5	5	4	10	49
Total	87	49	33	22	20	22	233
Dedesignated Risk Management Contracts (e)	14	14	6	5	-	-	39
Total MTM Risk Management Contract Net Assets (Liabilities)	$ 101	$ 63	$ 39	$ 27	$ 20	$ 22	$ 272

(a) Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 1 inputs primarily consist of exchange traded contracts that exhibit sufficient frequency and volume to provide pricing information on an ongoing basis.
(b) Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, exchange traded contracts where there was not sufficient market activity to warrant inclusion in Level 1, and OTC broker quotes that are corroborated by the same or similar transactions that have occurred in the market.
(c) Level 3 inputs are unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that the observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Level 3 inputs primarily consist of unobservable market data or are valued based on models and/or assumptions.
(d) A significant portion of the total volumetric position within the consolidated Level 3 balance has been economically hedged.
(e) Dedesignated Risk Management Contracts are contracts that were originally MTM but were subsequently elected as normal under SFAS 133. At the time of the normal election the MTM value was frozen and no longer fair valued. This will be amortized within Utility Operations Revenues over the remaining life of the contracts.
(f) There is mark-to-market value of $22 million in individual periods beyond 2013. $12 million of this mark-to-market value is in 2014, $4 million is in 2015, $3 million is in 2016 and $3 million is in 2017.

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 forecasted transactions denominated in foreign currencies where deemed necessary, and designate qualifying instruments as cash flow hedges. 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, 2007 to December 31, 2008. 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. All amounts are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2008
(in millions)

	Power	Interest Rate and Foreign Currency	Total
Beginning Balance in AOCI, December 31, 2007	$ (1)	$ (25)	$ (26)
Changes in Fair Value	6	(9)	(3)
Reclassifications from AOCI for Cash Flow Hedges Settled	2	5	7
Ending Balance in AOCI, December 31, 2008	$ 7	$ (29)	$ (22)
After Tax Portion Expected to be Reclassified to Earnings During Next 12 Months	$ 7	$ (5)	$ 2

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 originated. We use Moody's Investors Service, Standard & Poor's and current market-based qualitative and quantitative data to assess the financial health of counterparties on an ongoing basis. If an external rating is not available, an internal rating is generated utilizing a quantitative tool developed by Moody's to estimate probability of default that corresponds to an implied external agency credit rating. Based on our analysis, we set appropriate risk parameters for each internally-graded counterparty. We may also require cash deposits, letters of credit and parental/affiliate guarantees as security from counterparties in order to mitigate credit risk.

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. At December 31, 2008, our credit exposure net of collateral to sub investment grade counterparties was approximately 7.1%, 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, 2008, the following table approximates our counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable:

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties >10% of Net Exposure	Net Exposure of Counterparties >10%
	(in millions, except number of counterparties)				
Investment Grade	$ 622	$ 25	$ 597	2	$ 178
Split Rating	9	-	9	2	9
Noninvestment Grade	17	4	13	1	12
No External Ratings:					
Internal Investment Grade	103	-	103	2	56
Internal Noninvestment Grade	42	-	42	2	29
Total as of December 31, 2008	$ 793	$ 29	$ 764	9	$ 284
Total as of December 31, 2007	$ 673	$ 42	$ 631	6	$ 74

Collateral Triggering Events

Under a limited number of counterparty contracts primarily related to our pre-2002 risk management activities and under the tariffs of the Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs), we are obligated to post an amount of collateral if our credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and our total exposure. Our risk management organization assesses the appropriateness of these collateral triggering items in ongoing contract negotiations. We believe that a downgrade below investment grade is unlikely. As of December 31, 2008, we would have been required to post $174 million of collateral if our credit ratings had declined below investment grade of which $161 million is attributable to our RTO and ISO activities.

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, 2008, a near term typical change in commodity prices is not expected to have a material effect on our net income, 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, 2008 (in millions)				December 31, 2007 (in millions)			
End	**High**	**Average**	**Low**	**End**	**High**	**Average**	**Low**
$-	$3	$1	$-	$1	$6	$2	$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 historical-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 translated into the largest potential mark-to-market loss. We then research the underlying positions, price moves and market events 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 2009, the estimated EaR on our debt portfolio is $86 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, 2008 and 2007, 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, 2008. 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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 12 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 8 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.

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, 2008, 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 27, 2009 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2009

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, 2008, 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, 2008, 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, 2008 of the Company and our report dated February 27, 2009 expressed an unqualified opinion on those financial statements and included an explanatory paragraph concerning the Company's adoption of new accounting pronouncements in 2007 and 2006.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2009

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.

Management assessed the effectiveness of AEP's internal control over financial reporting as of December 31, 2008. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework. Based on management's assessment, AEP's internal control over financial reporting was effective as of December 31, 2008.

AEP's independent registered public accounting firm has issued an attestation report on AEP'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, 2008, 2007 and 2006
(in millions, except per-share and share amounts)

REVENUES	2008	2007	2006
Utility Operations	$ 13,326	$ 12,101	$ 12,066
Other	1,114	1,279	556
TOTAL	14,440	13,380	12,622
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	4,474	3,829	3,817
Purchased Electricity for Resale	1,281	1,138	856
Other Operation and Maintenance	3,925	3,867	3,639
Gain on Disposition of Assets, Net	(16)	(41)	(69)
Asset Impairments and Other Related Charges	(255)	-	209
Depreciation and Amortization	1,483	1,513	1,467
Taxes Other Than Income Taxes	761	755	737
TOTAL	11,653	11,061	10,656
OPERATING INCOME	2,787	2,319	1,966
Other Income:			
Interest and Investment Income	57	51	99
Carrying Costs Income	83	51	114
Allowance for Equity Funds Used During Construction	45	33	30
Gain on Disposition of Equity Investments, Net	-	47	3
INTEREST AND OTHER CHARGES			
Interest Expense	958	841	732
Preferred Stock Dividend Requirements of Subsidiaries	3	3	3
TOTAL	961	844	735
INCOME BEFORE INCOME TAX EXPENSE, MINORITY INTEREST EXPENSE AND EQUITY EARNINGS	2,011	1,657	1,477
Income Tax Expense	642	516	485
Minority Interest Expense	4	3	3
Equity Earnings of Unconsolidated Subsidiaries	3	6	3
INCOME BEFORE DISCONTINUED OPERATIONS AND EXTRAORDINARY LOSS	1,368	1,144	992
DISCONTINUED OPERATIONS, NET OF TAX	12	24	10
INCOME BEFORE EXTRAORDINARY LOSS	1,380	1,168	1,002
EXTRAORDINARY LOSS, NET OF TAX	-	(79)	-
NET INCOME	$ 1,380	$ 1,089	$ 1,002
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING	402,083,847	398,784,745	394,219,523
BASIC EARNINGS (LOSS) PER SHARE			
Income Before Discontinued Operations and Extraordinary Loss	$ 3.40	$ 2.87	$ 2.52
Discontinued Operations, Net of Tax	0.03	0.06	0.02
Income Before Extraordinary Loss	3.43	2.93	2.54
Extraordinary Loss, Net of Tax	-	(0.20)	-
TOTAL BASIC EARNINGS PER SHARE	$ 3.43	$ 2.73	$ 2.54
WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING	403,640,708	400,198,799	396,483,464
DILUTED EARNINGS (LOSS) PER SHARE			
Income Before Discontinued Operations and Extraordinary Loss	$ 3.39	$ 2.86	$ 2.50
Discontinued Operations, Net of Tax	0.03	0.06	0.03
Income Before Extraordinary Loss	3.42	2.92	2.53
Extraordinary Loss, Net of Tax	-	(0.20)	-
TOTAL DILUTED EARNINGS PER SHARE	$ 3.42	$ 2.72	$ 2.53
CASH DIVIDENDS PAID PER SHARE	$ 1.64	$ 1.58	$ 1.50

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2008 and 2007
(in millions)

	2008	2007
CURRENT ASSETS		
Cash and Cash Equivalents	$ 411	$ 178
Other Temporary Investments	327	365
Accounts Receivable:		
Customers	569	730
Accrued Unbilled Revenues	449	379
Miscellaneous	90	60
Allowance for Uncollectible Accounts	(42)	(52)
Total Accounts Receivable	1,066	1,117
Fuel	634	436
Materials and Supplies	539	531
Risk Management Assets	256	271
Regulatory Asset for Under-Recovered Fuel Costs	284	11
Margin Deposits	86	47
Prepayments and Other	172	70
TOTAL	3,775	3,026
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	21,242	20,233
Transmission	7,938	7,392
Distribution	12,816	12,056
Other (including coal mining and nuclear fuel)	3,741	3,445
Construction Work in Progress	3,973	3,019
Total	49,710	46,145
Accumulated Depreciation and Amortization	16,723	16,275
TOTAL - NET	32,987	29,870
OTHER NONCURRENT ASSETS		
Regulatory Assets	3,783	2,199
Securitized Transition Assets	2,040	2,108
Spent Nuclear Fuel and Decommissioning Trusts	1,260	1,347
Goodwill	76	76
Long-term Risk Management Assets	355	319
Employee Benefits and Pension Assets	3	486
Deferred Charges and Other	876	888
TOTAL	8,393	7,423
TOTAL ASSETS	$ 45,155	$ 40,319

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2008 and 2007

	2008	2007
	(in millions)	
CURRENT LIABILITIES		
Accounts Payable	$ 1,297	$ 1,324
Short-term Debt	1,976	660
Long-term Debt Due Within One Year	447	792
Risk Management Liabilities	134	240
Customer Deposits	254	301
Accrued Taxes	634	601
Accrued Interest	270	235
Other	1,285	1,008
TOTAL	6,297	5,161
NONCURRENT LIABILITIES		
Long-term Debt	15,536	14,202
Long-term Risk Management Liabilities	170	188
Deferred Income Taxes	5,128	4,730
Regulatory Liabilities and Deferred Investment Tax Credits	2,789	2,952
Asset Retirement Obligations	1,154	1,075
Employee Benefits and Pension Obligations	2,184	712
Deferred Credits and Other	1,143	1,159
TOTAL	28,104	25,018
TOTAL LIABILITIES	34,401	30,179
Cumulative Preferred Stock Not Subject to Mandatory Redemption	61	61
Commitments and Contingencies (Note 6)		
COMMON SHAREHOLDERS' EQUITY		
Common Stock Par Value $6.50:		

	2008	2007
Shares Authorized	600,000,000	600,000,000
Shares Issued	426,321,248	421,926,696

	2008	2007
(20,249,992 shares and 21,499,992 shares were held in treasury at December 31, 2008 and 2007, respectively)	2,771	2,743
Paid-in Capital	4,527	4,352
Retained Earnings	3,847	3,138
Accumulated Other Comprehensive Income (Loss)	(452)	(154)
TOTAL	10,693	10,079
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 45,155	$ 40,319

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, 2008, 2007 and 2006
(in millions)

	2008	2007	2006
OPERATING ACTIVITIES			
Net Income	$ 1,380	$ 1,089	$ 1,002
Less: Discontinued Operations, Net of Tax	(12)	(24)	(10)
Income Before Discontinued Operations	1,368	1,065	992
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	1,483	1,513	1,467
Deferred Income Taxes	498	76	24
Provision for Revenue Refund	149	-	-
Extraordinary Loss, Net of Tax	-	79	-
Asset Impairments, Investment Value Losses and Other Related Charges	-	-	209
Carrying Costs Income	(83)	(51)	(114)
Allowance for Equity Funds Used During Construction	(45)	(33)	(30)
Mark-to-Market of Risk Management Contracts	(140)	3	(191)
Amortization of Nuclear Fuel	88	65	50
Deferred Property Taxes	(13)	(26)	(14)
Fuel Over/Under-Recovery, Net	(272)	(117)	182
Gain on Sales of Assets and Equity Investments, Net	(17)	(88)	(72)
Change in Noncurrent Liability for NSR Settlement	-	58	-
Change in Other Noncurrent Assets	(199)	(98)	15
Change in Other Noncurrent Liabilities	(34)	66	(1)
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	71	(113)	177
Fuel, Materials and Supplies	(183)	16	(187)
Margin Deposits	(40)	50	(13)
Accounts Payable	(94)	(21)	56
Customer Deposits	(48)	49	36
Accrued Taxes, Net	4	(90)	128
Accrued Interest	30	11	4
Other Current Assets	(29)	(11)	17
Other Current Liabilities	82	(15)	(3)
Net Cash Flows from Operating Activities	2,576	2,388	2,732
INVESTING ACTIVITIES			
Construction Expenditures	(3,800)	(3,556)	(3,528)
Change in Other Temporary Investments, Net	45	(114)	(33)
Purchases of Investment Securities	(1,922)	(11,086)	(18,359)
Sales of Investment Securities	1,917	11,213	18,080
Acquisitions of Nuclear Fuel	(192)	(74)	(89)
Acquisitions of Assets	(160)	(512)	-
Proceeds from Sales of Assets	90	222	186
Other	(5)	(14)	-
Net Cash Flows Used for Investing Activities	(4,027)	(3,921)	(3,743)
FINANCING ACTIVITIES			
Issuance of Common Stock	159	144	99
Issuance of Long-term Debt	2,774	2,546	3,359
Change in Short-term Debt, Net	1,316	642	7
Retirement of Long-term Debt	(1,824)	(1,286)	(1,946)
Proceeds from Nuclear Fuel Sale/Leaseback	-	85	-
Principal Payments for Capital Lease Obligations	(97)	(67)	(63)
Dividends Paid on Common Stock	(660)	(630)	(591)
Dividends Paid on Cumulative Preferred Stock	(3)	(3)	(3)
Other	19	(21)	49
Net Cash Flows from Financing Activities	1,684	1,410	911
Net Increase (Decrease) in Cash and Cash Equivalents	233	(123)	(100)
Cash and Cash Equivalents at Beginning of Period	178	301	401
Cash and Cash Equivalents at End of Period	$ 411	$ 178	$ 301

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, 2008, 2007, and 2006
(in millions)

	Common Stock				Accumulated Other	
	Shares	Amount	Paid-in Capital	Retained Earnings	Comprehensive Income (Loss)	Total
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						8,606
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		1,002
TOTAL COMPREHENSIVE INCOME						1,024
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						8,921
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 Related to 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		1,089
TOTAL COMPREHENSIVE INCOME						1,158
DECEMBER 31, 2007	422	2,743	4,352	3,138	(154)	10,079
EITF 06-10 Adoption, Net of Tax of $6				(10)		(10)
SFAS 157 Adoption, Net of Tax of $0				(1)		(1)
Issuance of Common Stock	4	28	131			159
Reissuance of Treasury Shares			40			40
Common Stock Dividends				(660)		(660)
Other			4			4
TOTAL						9,611
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss), Net of Taxes:						
Cash Flow Hedges, Net of Tax of $2					4	4
Securities Available for Sale, Net of Tax of $9					(16)	(16)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $7					12	12
Pension and OPEB Funded Status, Net of Tax of $161					(298)	(298)
NET INCOME				1,380		1,380
TOTAL COMPREHENSIVE INCOME						1,082
DECEMBER 31, 2008	426	$ 2,771	$ 4,527	$ 3,847	$ (452)	$ 10,693

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
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1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

The principal business conducted by seven of our electric utility operating companies is the generation, transmission and distribution of electric power. TCC exited the generation business and along with WPCo and KGPCo, provide only transmission and distribution services. TNC is a part owner in the Oklaunion Plant operated by PSO. TNC leases their entire portion of the output of the plant through 2027 to a non-utility affiliate. 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 and barging operations and we provide various energy-related services.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

Our public utility subsidiaries' rates are regulated by the FERC and state regulatory commissions in our eleven state operating territories. The state regulatory commissions approve retail rates 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 our affiliated transactions, including AEPSC intercompany service billing which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. 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 and mergers with another electric utility or holding company. A FERC order in 2008 pursuant to the Federal Power Act codified that for non-power goods and services, a non-regulated affiliate can bill a public utility company no more than market while a public utility must bill the higher of cost or market to a non-regulated affiliate. The state regulatory commissions in Virginia and West Virginia also regulate certain intercompany transactions under their affiliates statutes.

The FERC regulates wholesale power markets and wholesale power transactions. Our wholesale power transactions are generally market-based. They are cost-based regulated when we negotiate and file a cost-based contract with the FERC or the FERC determines that we have "market power" in the region where the transaction occurs. We enter into wholesale power supply contracts with various municipalities and cooperatives that are FERC-regulated, cost-based contracts. Our wholesale power transactions in the SPP region are cost-based due to SWEPCo and PSO having market power in the SPP region.

The FERC also regulates, on a cost basis, our wholesale transmission service and rates except in Texas. The FERC claims jurisdiction over retail transmission rates when retail rates are unbundled in connection with restructuring. CSPCo's and OPCo's retail rates in Ohio, APCo's retail rates in Virginia, I&M's retail rates in Michigan and TCC's and TNC's retail rates in Texas are unbundled. Therefore, CSPCo's and OPCo's retail transmission rates are based on the FERC's Open Access Transmission Tariff (OATT) rates that are cost-based. Although APCo's retail rates in Virginia, I&M's retail rates in Michigan and TCC's and TNC's retail rates in Texas are unbundled, retail transmission rates are regulated, on a cost basis, by the state regulatory commissions. Starting in 2009, APCo may file, and the Virginia SCC shall approve, a rate adjustment clause that passes through charges associated with the FERC's OATT rates to APCo's Virginia retail customers. Bundled retail transmission rates are regulated, on a cost basis, by the state commissions.

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

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. These rates were subject to RSPs through December 31, 2008. The PUCO extended these rates until they issue a ruling on the ESPs or the end of the February 2009 billing cycle, whichever comes first. The ESP rates are under recently enacted legislation, which continues the concept of increasing rates over time to approach market rates. 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 2007, the Virginia legislation ended a transition to market-based rates and returned APCo to cost-based regulation. See Note 4 for further information on restructuring legislation and its effects on AEP in Ohio, Texas and Michigan.

Both the FERC and state regulatory commissions 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 our wholly-owned and majority-owned subsidiaries and variable interest entities (VIEs) of which we are the primary beneficiary. Intercompany items are eliminated in consolidation. Equity investments not substantially-controlled and which we are not the primary beneficiary of the entity, that are 50% or less owned are accounted for using the equity method of accounting and recorded 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. For years, we have had ownership interests in 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.

FIN 46R is a consolidation model that considers risk absorption of a variable interest entity (VIE), also referred to as variability. Entities are required to consolidate a VIE when it is determined that they are the primary beneficiary of that VIE, as defined by FIN 46R. In determining whether we are the primary beneficiary of a VIE, we consider factors such as equity at risk, the amount of variability of the VIE we absorb, guarantees of indebtedness, voting rights including kick-out rights, power to direct the VIE and other factors. We believe that significant assumptions and judgments have been consistently applied and that there are no other reasonable judgments or assumptions that would have resulted in a different conclusion.

We are the primary beneficiary of Sabine, DHLC, JMG and a protected cell of EIS. We hold a variable interest in Potomac-Appalachian Transmission Highline, LLC West Virginia Series (West Virginia Series). In addition, we have not provided financial or other support that was not previously contractually required to any VIE.

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine’s only customer. SWEPCo has guaranteed the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee which is included in Fuel and Other Consumables Used for Electric Generation on our Consolidated Statements of Income. Based on these facts, management has concluded SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo’s total billings from Sabine for the years ended December 31, 2008 and 2007 were $110 million and $95 million, respectively. See the tables below for the classification of Sabine’s assets and liabilities on our Consolidated Balance Sheets.

DHLC is a wholly-owned subsidiary of SWEPCo. DHLC is a mining operator who sells 50% of the lignite produced to SWEPCo and 50% to Cleco Corporation, a nonaffiliated company. SWEPCo and Cleco Corporation share half of the executive board seats, with equal voting rights and each entity guarantees a 50% share of DHLC's debt. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. Based on the structure and equity ownership, management has concluded that SWEPCo is the primary beneficiary and is required to consolidate DHLC. SWEPCo's total billings from DHLC for the years ended December 31, 2008 and 2007 were $44 million and $35 million, respectively. These billings are included in Fuel and Other Consumables Used for Electric Generation on our Consolidated Statements of Income. See the tables below for the classification of DHLC assets and liabilities on our Consolidated Balance Sheets.

OPCo has a lease agreement with JMG to finance OPCo's FGD system installed on OPCo's Gavin Plant. The PUCO approved the original lease agreement between OPCo and JMG. JMG has a capital structure of substantially all debt from pollution control bonds and other debt. JMG owns and leases the FGD to OPCo. JMG is considered a single-lessee leasing arrangement with only one asset. OPCo's lease payments are the only form of repayment associated with JMG's debt obligations even though OPCo does not guarantee JMG's debt. The creditors of JMG have no recourse to any AEP entity other than OPCo for the lease payment. OPCo does not have any ownership interest in JMG. Based on the structure of the entity, management has concluded OPCo is the primary beneficiary and is required to consolidate JMG. OPCo's total billings from JMG for the years ended December 31, 2008 and 2007 were $57 million and $46 million, respectively. See the tables below for the classification of JMG's assets and liabilities on our Consolidated Balance Sheets.

EIS is a captive insurance company with multiple protected cells in which our subsidiaries participate in one protected cell for approximately ten lines of insurance. Neither AEP nor its subsidiaries have an equity investment in EIS. The AEP system is essentially this EIS cell's only participant, but allow certain third parties access to this insurance. Our subsidiaries and any allowed third parties share in the insurance coverage, premiums and risk of loss from claims. Based on the structure of the protected cell, we have concluded that we are the primary beneficiary and that we are required to consolidate the protected cell. Our insurance premium payments to EIS for the years ended December 31, 2008 and 2007 were $28 million and $26 million, respectively. See the tables below for the classification of EIS's assets and liabilities on our Consolidated Balance Sheets.

The balances below represent the assets and liabilities of the VIEs that are consolidated. These balances include intercompany transactions that would be eliminated upon consolidation.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2008
(in millions)

	SWEPCo Sabine	SWEPCo DHLC	OPCo JMG	EIS
ASSETS				
Current Assets	$ 33	$ 22	$ 11	$ 107
Net Property, Plant and Equipment	117	33	423	-
Other Noncurrent Assets	24	11	1	2
Total Assets	$ 174	$ 66	$ 435	$ 109
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current Liabilities	$ 32	$ 18	$ 161	$ 30
Noncurrent Liabilities	142	44	257	60
Common Shareholders' Equity	-	4	17	19
Total Liabilities and Shareholders' Equity	$ 174	$ 66	$ 435	$ 109

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2007
(in millions)

	SWEPCo Sabine	SWEPCo DHLC	OPCo JMG	EIS
ASSETS				
Current Assets	$ 24	$ 29	$ 5	$ -
Net Property, Plant and Equipment	97	41	443	-
Other Noncurrent Assets	25	13	1	21
Total Assets	$ 146	$ 83	$ 449	$ 21
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current Liabilities	$ 14	$ 26	$ 98	$ -
Noncurrent Liabilities	130	54	335	-
Common Shareholders' Equity	2	3	16	21
Total Liabilities and Shareholders' Equity	$ 146	$ 83	$ 449	$ 21

In September 2007, we and Allegheny (AYE) formed a joint venture by creating Potomac-Appalachian Transmission Highline, LLC (PATH). PATH is a series limited liability company and was created to construct a high-voltage transmission line project in the PJM region. PATH consists of the "Ohio Series," the "West Virginia Series (PATH-WV)," both owned equally by AYE and us and the "Allegheny Series" which is 100% owned by AYE. Provisions exist within the PATH-WV agreement that make it a VIE. The "Ohio Series" does not include the same provision that makes PATH-WV a VIE. The other series are not considered VIEs. We are not required to consolidate PATH-WV as we are not the primary beneficiary, although we hold a significant interest in PATH-WV. Our equity investment in PATH-WV is included in Deferred Charges and Other on our Consolidated Balance Sheets. We and AYE share the returns and losses equally in PATH-WV. Our subsidiaries and AYE's subsidiaries provide services to the PATH companies through service agreements. At the current time, PATH-WV has no debt outstanding. However, when debt is issued, the debt to equity ratio in each series will be consistent with other regulated utilities and the entities are designed to maintain this financing structure. The entities recover costs through regulated rates.

Given the structure of the entity, we may be required to provide future financial support to PATH-WV in the form of a capital call. This would be considered an increase to our investment in the entity. Our maximum exposure to loss is to the extent of our investment. Currently the entity has no debt financing. The likelihood of such a loss is remote since the FERC approved PATH-WV's request for regulatory recovery of cost and a return on the equity invested.

Our investment in PATH-WV as of December 31, 2008 was:

	As Reported on the Consolidated Balance Sheet	Maximum Exposure
	(in millions)	
Capital Contribution from Parent	$ 4	$ 4
Retained Earnings	2	2
Total Investment in PATH-WV	$ 6	$ 6

We record our investment in PATH-WV in Deferred Charges and Other on our Consolidated Balance Sheets. As of December 31, 2007, we did not make a capital contribution to PATH-WV and therefore had no retained earnings.

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 as follows: in Ohio for OPCo and CSPCo in September 2000, in Virginia for APCo in June 2000 and in Texas for TCC and 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 business and 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. Consistent with 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 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 AEP River 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 is capitalized and recovered through depreciation over the service life of regulated electric utility plant. For nonregulated operations, including 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, investments by our protected cell insurance company 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.

In evaluating potential impairment of securities with unrealized losses, we considered, among other criteria, the current fair value compared to cost, the length of time the security's fair value has been below cost, our intent and ability to retain the investment for a period of time sufficient to allow for any anticipated recovery in value and current economic conditions. During 2008, 2007 and 2006, we did not record any other-than-temporary impairments of Other Temporary Investments.

The following is a summary of Other Temporary Investments:

	December 31,							
	2008				2007			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	(in millions)							
Cash (a)	$ 243	$ -	$ -	$ 243	$ 273	$ -	$ -	$ 273
Debt Securities	56	-	-	56	66	-	-	66
Corporate Equity Securities	27	11	10	28	-	26	-	26
Total Other Temporary Investments	$ 326	$ 11	$ 10	$ 327	$ 339	$ 26	$ -	$ 365

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

Proceeds from sales of current available-for-sale securities were $1.2 billion, $10.5 billion and $17.4 billion in 2008, 2007 and 2006, respectively. Purchases of current available-for-sale securities were $1.1 billion, $10.3 billion and $17.7 billion in 2008, 2007 and 2006, respectively. During 2008, there were no gross realized gains or losses from the sale of current available-for-sale securities. Gross realized gains from the sale of current available-for-sale securities were $16 million and $39 million in 2007 and 2006, respectively. Gross realized losses from the sale of current available-for-sale securities were not material in 2007 or 2006. At December 31, 2008, the fair value of corporate equity securities with an unrealized loss position was $17 million and we had no investments in a continuous unrealized loss position for more than twelve months. At December 31, 2008, the fair value of debt securities are primarily debt based mutual funds with short-term, intermediate and long-term maturities.

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 sales when we deliver power 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 14).

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. The cost of fuel also includes the amortization of nuclear fuel costs which are computed primarily on the units-of-production method. Where applicable under governing state regulatory commission retail rate orders, fuel cost over-recoveries (the excess of fuel revenues billed to customers over applicable fuel costs incurred) are deferred as current regulatory liabilities and under-recoveries (the excess of applicable 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 and deferrals. When a fuel cost disallowance becomes probable, we adjust our deferrals and record provisions for estimated refunds to recognize these probable outcomes. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when the fuel clauses have been suspended or terminated.

In general, changes in fuel costs in Kentucky for KPCo, Indiana (beginning July 1, 2007) and Michigan for I&M, Texas, Louisiana and Arkansas for SWEPCo, Oklahoma for PSO and 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 of the profits from off-system sales are shared with customers through fuel clauses in West Virginia (beginning July 1, 2006). A portion of profits from off-system sales are shared with customers through fuel clauses in Texas, Oklahoma, Louisiana, Arkansas, Kentucky, 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.

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) and regulatory liabilities (deferred 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 at each balance sheet date or whenever new events occur. Examples include 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 income.

Traditional Electricity Supply and Delivery Activities

Revenues are recognized from retail and wholesale electricity 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. We purchase power from PJM to supply our customers. 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 exchanges.

Physical energy purchases, including those from 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 Electricity 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 Electricity 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 11).

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 and adjacent markets. 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, as well as 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 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 AOCI. When the forecasted transaction is realized and affects net income, we subsequently reclassify the gain or loss on the hedge from Accumulated Other Comprehensive Income into revenues or expenses within the same financial statement line item as the forecasted transaction on our Consolidated Statements of Income. Excluding those jurisdictions subject to cost-based regulation, we recognize the ineffective portion of the gain or loss in revenues or expense immediately on our Consolidated Statements of Income, depending on the specific nature of the associated hedged risk. In 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 11).

Barging Activities

AEP River 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 our 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. We include such revenue and related expenses in Utility Operations revenue and Other Operation and Maintenance expense on our Consolidated Statements of Income. We also include contractually billable expenses not yet billed in Current Assets on our Consolidated Balance Sheets.

Levelization of Nuclear Refueling Outage Costs

In order to match costs with nuclear refueling cycles, I&M defers incremental operation and maintenance costs associated with periodic refueling outages at its Cook Plant and amortizes the costs over the period beginning with the month following the start of each unit's refueling outage and lasting until the end of the month in which the same unit's next scheduled refueling outage begins. I&M adjusts the amortization amount as necessary to ensure full amortization of all deferred costs by the end of the refueling cycle.

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 distribution tree trimming costs for PSO and amortize the costs above the level included in base rates 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 beginning January 1, 2007, 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 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 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 15 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 SO_2 and NO_x emission allowance entitlements received at no cost from the Federal EPA and States. We follow the inventory model for these allowances. We record allowances expected to be consumed within one year in 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. Other-than-temporary impairments are considered realized losses as we do not make specific investment decisions regarding the assets held in these trusts. They 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 9 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)(AOCI)

AOCI 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 AOCI:

	December 31,	
	2008	**2007**
Components	**(in millions)**	
Securities Available for Sale, Net of Tax	$ 1	$ 17
Cash Flow Hedges, Net of Tax	(22)	(26)
Amortization of Pension and OPEB Deferred Costs, Net of Tax	12	-
Pension and OPEB Funded Status, Net of Tax	(443)	(145)
Total	$ (452)	$ (154)

Stock-Based Compensation Plans

At December 31, 2008, 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 last approved by shareholders 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. Dividends paid on career shares are reinvested as additional career shares.

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 become payable in cash to Directors 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.

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 2008, 2007 and 2006, we granted awards with performance conditions which are expensed on the accelerated multiple-option approach. Stock-based compensation expense recognized on our Consolidated Statements of Income for the years ended December 31, 2008, 2007 and 2006 is based on awards ultimately expected to vest. Therefore, stock-based compensation expense has been reduced to reflect 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.

For the years ended December 31, 2008, 2007 and 2006, 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 15 for additional discussion.

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,					
	2008		2007		2006	
	(in millions, except per share data)					
		$/share		$/share		$/share
Earnings Applicable to Common Stock	$ 1,380		$ 1,089		$ 1,002	
Average Number of Basic Shares Outstanding	402.1	$ 3.43	398.8	$ 2.73	394.2	$ 2.54
Average Dilutive Effect of:						
Performance Share Units	1.2	0.01	0.9	0.01	1.8	0.01
Stock Options	0.1	-	0.3	-	0.3	-
Restricted Stock Units	0.1	-	0.1	-	0.1	-
Restricted Shares	0.1	-	0.1	-	0.1	-
Average Number of Diluted Shares Outstanding	403.6	$ 3.42	400.2	$ 2.72	396.5	$ 2.53

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

Options to purchase 470,016, 83,150 and 367,500 shares of common stock were outstanding at December 31, 2008, 2007 and 2006, respectively, but were not included in the computation of diluted earnings per share. Since the options' exercise prices were greater than the year-end market price of the common shares, the effect would be antidilutive.

Supplementary Information

	Years Ended December 31,		
	2008	2007	2006
Related Party Transactions	(in millions)		
AEP Consolidated Revenues – Utility Operations:			
Power Pool Purchases – Ohio Valley Electric Corporation (43.47% Owned)	$ (54)	$ (29)	$ (37)
AEP Consolidated Revenues – Other:			
Ohio Valley Electric Corporation – Barging and Other Transportation Services (43.47% Owned)	32	31	28
AEP Consolidated Expenses – Purchased Energy for Resale:			
Ohio Valley Electric Corporation (43.47% Owned)	263	226	223
Sweeny Cogeneration Limited Partnership (a)	-	86	121

(a) In October 2007, we sold our 50% ownership in the Sweeny Cogeneration Limited Partnership. See "Sweeny Cogeneration Plant" section of Note 7.

Cash Flow Information	2008	2007	2006
	Years Ended December 31, (in millions)		
Cash paid for:			
Interest, Net of Capitalized Amounts	$ 853	$ 734	$ 664
Income Taxes, Net of Refunds	233	576	358
Noncash Investing and Financing Activities:			
Acquisitions Under Capital Leases	62	160	106
Assumption of Liabilities Related to Acquisitions/Divestitures, Net	-	8	-
Disposition of Assets Related to Electric Transmission Texas Joint Venture	-	(14)	-
Construction Expenditures Included in Accounts Payable at December 31,	460	345	404
Acquisition of Nuclear Fuel Included in Accounts Payable at December 31,	38	84	-
Noncash Donation Expense Related to Issuance of Treasury Shares to AEP Foundation	40	-	-

Transmission Investments

We participate in certain joint ventures which involve transmission projects to own and operate transmission facilities. These investments are 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 nonregulated 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 7).

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. See "FSP FIN 39-1 "Amendment of FASB Interpretation No. 39" section of Note 2 for discussion of changes in netting certain balance sheet amounts. These reclassifications had no impact on our previously reported net income or changes in shareholders' equity.

2. NEW ACCOUNTING PRONOUNCEMENTS AND EXTRAORDINARY ITEM

NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, we review the new accounting literature to determine its relevance, if any, to our business. The following represents a summary of final pronouncements that we have determined relate to our operations.

Pronouncements Adopted in 2008

The following standards were effective during 2008. Consequently, the financial statements and footnotes reflect their impact.

SFAS 157 "Fair Value Measurements" (SFAS 157)

We partially adopted SFAS 157 effective January 1, 2008. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures.

In February 2008, the FASB issued FSP SFAS 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" (SFAS 157-1) which amends SFAS 157 to exclude SFAS 13 "Accounting for Leases" (SFAS 13) and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement under SFAS 13. SFAS 157-1 was effective upon issuance and had an immaterial impact on our financial statements.

In February 2008, the FASB issued FSP SFAS 157-2 "Effective Date of FASB Statement No. 157" (SFAS 157-2) 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 adopted SFAS 157 effective January 1, 2009 for items within the scope of SFAS 157-2. The adoption of SFAS 157-2 had an immaterial impact on our financial statements.

In October 2008, the FASB issued FSP SFAS 157-3 "Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active" which clarifies application of SFAS 157 in markets that are not active and provides an illustrative example. The FSP was effective upon issuance. The adoption of this standard had no impact on our financial statements.

See "SFAS 157 Fair Value Measurements" Section of Note 11 for further information.

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

The FASB permitted entities to choose to measure many financial instruments and certain other items at fair value. The standard also established 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 162 "The Hierarchy of Generally Accepted Accounting Principles" (SFAS 162)

In May 2008, the FASB issued SFAS 162, clarifying the sources of generally accepted accounting principles in descending order of authority. The statement specifies that the reporting entity, not its auditors, is responsible for its compliance with GAAP.

We adopted SFAS 162 in the fourth quarter of 2008. The adoption of this standard had no impact on our financial statements.

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 if the employer 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 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) retrospective application to all prior periods. We adopted EITF 06-10 effective January 1, 2008 with a cumulative effect reduction of $16 million ($10 million, net of tax) to beginning retained earnings.

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 addressed the recognition of income tax benefits of dividends on employee share-based compensation. 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. The adoption of this standard had an immaterial impact on our financial statements.

FSP SFAS 133-1 and FIN 45-4 "Disclosures about Credit Derivatives and Certain Guarantees: An Amendment of FASB Statement No. 133 and FASB Interpretation No. 45; and Clarification of the Effective Date of FASB Statement No. 161" (FSP SFAS 133-1 and FIN 45-4)

In September 2008, the FASB issued FSP SFAS 133-1 and FIN 45-4 amending SFAS 133 and FIN 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." Under the SFAS 133 requirements, the seller of a credit derivative shall disclose the following information for each derivative, including credit derivatives embedded in a hybrid instrument, even if the likelihood of payment is remote:

(a) The nature of the credit derivative.
(b) The maximum potential amount of future payments.
(c) The fair value of the credit derivative.
(d) The nature of any recourse provisions and any assets held as collateral or by third parties.

Further, the standard requires the disclosure of current payment status/performance risk of all FIN 45 guarantees. In the event an entity uses internal groupings, the entity shall disclose how those groupings are determined and used for managing risk.

We adopted the standard effective December 31, 2008. The adoption of this standard had no impact on our financial statements but increased our guarantees disclosures in Note 6.

FSP SFAS 140-4 and FIN 46R-8 "Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interests in Variable Interest Entities" (FSP SFAS 140-4 and FIN 46R-8)

In December 2008, the FASB issued FSP SFAS 140-4 and FIN 46R-8 amending SFAS 140 "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities" and FIN 46R "Consolidation of Variable Interest Entities." Under the requirements, the transferor of financial assets in the securitization or asset-backed financing arrangement must disclose the following:

(a) Nature of any restrictions on assets reported by an entity in its balance sheet that relate to a transferred financial asset, including the carrying amounts of such assets.
(b) Method of reporting servicing assets and servicing liabilities.
(c) If reported as sales and the transferor has continuing involvement with the transferred financial assets and the transfers are accounted for as secured borrowings, how the transfer of financial assets affects the transferors' balance sheet, net income and cash flows.

The FIN 46R amendments contain disclosure requirements for a public enterprise that (a) is the primary beneficiary of a variable interest entity (VIE), (b) holds a significant variable interest in a VIE but is not the primary beneficiary or (c) is a sponsor that holds a variable interest in a VIE. The principle objectives of the disclosures required by this standard are to provide financial statement users an understanding of:

(a) Significant judgments and assumptions made to determine whether to consolidate a variable interest entity and/or disclose information about involvement with a variable interest entity.
(b) Nature of the restrictions on a consolidated variable interest entity's assets reported in the balance sheet, including the carrying amounts of such assets.
(c) Nature of, and changes in, risks associated with a company's involvement with a variable interest entity.
(d) A variable interest entity's effect on the balance sheet, net income and cash flows.
(e) The nature, purpose, size and activities of any variable interest equity, including how it is financed.

We adopted the standard effective December 31, 2008. The adoption of this standard had no impact on our financial statements but increased our footnote disclosures for variable interest entities. See "Principles of Consolidation" section of Note 1.

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

In April 2007, the FASB issued FSP FIN 39-1 amending FIN 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. The amendment 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 the standard effective January 1, 2008. This standard changed our method of netting certain balance sheet amounts and reduced assets and liabilities. It requires retrospective application as a change in accounting principle. Consequently, we reclassified the following amounts on the December 31, 2007 Consolidated Balance Sheet as shown:

Balance Sheet Line Description	**As Reported for the December 2007 10-K**	**FSP FIN 39-1 Reclassification**	**As Reported for the December 2008 10-K**
Current Assets:		**(in millions)**	
Risk Management Assets	$ 286	$ (15)	$ 271
Margin Deposits	58	(11)	47
Long-term Risk Management Assets	340	(21)	319
Current Liabilities:			
Risk Management Liabilities	250	(10)	240
Customer Deposits	337	(36)	301
Long-term Risk Management Liabilities	189	(1)	188

For certain risk management contracts, we are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the December 31, 2008 balance sheet, we netted $11 million of cash collateral received from third parties against short-term and long-term risk management assets and $43 million of cash collateral paid to third parties against short-term and long-term risk management liabilities.

Pronouncements Adopted During The First Quarter of 2009

The following standards are effective during the first quarter of 2009. Consequently, their impact will be reflected in the first quarter of 2009 financial statements when filed. The following paragraphs discuss their expected impact on future financial statement and footnote disclosures.

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 established 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. The standard 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 can affect tax positions on previous acquisitions. We do not have any such tax positions that result in adjustments.

We adopted SFAS 141R effective January 1, 2009. It is effective prospectively for business combinations with an acquisition date on or after January 1, 2009. We will apply it to any future business combinations.

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. The statement 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.

We adopted SFAS 160 effective January 1, 2009. The adoption of this standard had an immaterial impact and will be applied retrospectively to prior period financial statements in future filings so the presentation of noncontrolling interest is comparable.

SFAS 161 "Disclosures about Derivative Instruments and Hedging Activities" (SFAS 161)

In March 2008, the FASB issued SFAS 161, enhancing disclosure requirements for derivative instruments and hedging activities. Affected entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how an entity accounts for derivative instruments and related hedged items and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. The standard requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation.

We adopted SFAS 161 effective January 1, 2009. This standard will increase our disclosure requirements related to derivative instruments and hedging activities in future reports.

EITF Issue No. 08-5 "Issuer's Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement" (EITF 08-5)

In September 2008, the FASB ratified the consensus on liabilities with third-party credit enhancements when the liability is measured and disclosed at fair value. The consensus treats the liability and the credit enhancement as two units of accounting. Under the consensus, the fair value measurement of the liability does not include the effect of the third-party credit enhancement. Consequently, changes in the issuer's credit standing without the support of the credit enhancement affect the fair value measurement of the issuer's liability. Entities will need to provide disclosures about the existence of any third-party credit enhancements related to their liabilities. In the period of adoption, entities must disclose the valuation method(s) used to measure the fair value of liabilities within its scope and any change in the fair value measurement method that occurs as a result of its initial application.

We adopted EITF 08-5 effective January 1, 2009. It will be applied prospectively with the effect of initial application included as a change in fair value of the liability in the period of adoption. The adoption of this standard will impact the financial statements in the 2009 Annual Report as we report fair value of long-term debt annually.

EITF Issue No. 08-6 "Equity Method Investment Accounting Considerations" (EITF 08-6)

In November 2008, the FASB ratified the consensus on equity method investment accounting including initial and allocated carrying values and subsequent measurements. It requires initial carrying value be determined using the SFAS 141R cost allocation method. When an investee issues shares, the equity method investor should treat the transaction as if the investor sold part of its interest.

We adopted EITF 08-6 effective January 1, 2009 with no impact on our financial statements. It was applied prospectively.

FSP EITF 03-6-1 "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities" (EITF 03-6-1)

In June 2008, the FASB addressed whether instruments granted in share-based payment transactions are participating securities prior to vesting and determined that the instruments need to be included in earnings allocation in computing EPS under the two-class method described in SFAS 128 "Earnings per Share."

We adopted EITF 03-6-1 effective January 1, 2009. The adoption of this standard had an immaterial impact on our financial statements.

FSP SFAS 142-3 "Determination of the Useful Life of Intangible Assets" (SFAS 142-3)

In April 2008, the FASB issued SFAS 142-3 amending factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset. The standard is expected to improve consistency between the useful life of a recognized intangible asset and the period of expected cash flows used to measure its fair value.

We adopted SFAS 142-3 effective January 1, 2009. The guidance is prospectively applied to intangible assets acquired after the effective date. The standard's disclosure requirements are applied prospectively to all intangible assets as of January 1, 2009. The adoption of this standard had no impact on our financial statements.

Pronouncements Effective in the Future

The following standards will be effective in the future and their impacts disclosed at that time.

FSP SFAS 132R-1 "Employers' Disclosures about Postretirement Benefit Plan Assets" (FSP SFAS 132R-1)

In December 2008, the FASB issued FSP SFAS 132R-1 providing additional disclosure guidance for pension and OPEB plan assets. The rule requires disclosure of investment policy including target allocations by investment class, investment goals, risk management policies and permitted or prohibited investments. It specifies a minimum of investment classes by further dividing equity and debt securities by issuer grouping. The standard adds disclosure requirements including hierarchical classes for fair value and concentration of risk.

This standard is effective for fiscal years ending after December 15, 2009. Management expects this standard to increase the disclosure requirements related to our benefit plans. We will adopt the standard effective for the 2009 Annual Report.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued, 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, contingencies, liabilities and equity, emission allowances, earnings per share calculations, leases, insurance, hedge accounting consolidation policy, trading inventory 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 net income and financial position.

EXTRAORDINARY ITEM

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.

3. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

The changes in our carrying amount of goodwill for the years ended December 31, 2008 and 2007 by operating segment are as follows:

	Utility Operations	AEP River Operations	AEP Consolidated
		(in millions)	
Balance at December 31, 2006	$ 37	$ 39	$ 76
Impairment Losses	-	-	-
Balance at December 31, 2007	37	39	76
Impairment Losses	-	-	-
Balance at December 31, 2008	$ 37	$ 39	$ 76

In the fourth quarters of 2008 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 $12.8 million and $15.2 million at December 31, 2008 and 2007, respectively, 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,			
		2008		2007	
	Amortization Life	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(in years)		(in millions)		
Patent	5	$ -	$ -	$ 0.1	$ 0.1
Easements	10	2.2	1.6	2.2	1.4
Purchased Technology	10	10.9	7.5	10.9	6.4
Advanced Royalties	15	29.4	20.6	29.4	19.5
Total		$ 42.5	$ 29.7	$ 42.6	$ 27.4

Amortization of intangible assets was $3 million, $4 million and $5 million for 2008, 2007 and 2006, respectively. Our estimated total amortization is $3 million per year for 2009 through 2010, $2 million for 2011 and $1 million per year for 2012 through 2016, when all assets will be fully amortized with no residual value.

The Advanced Royalties asset class relates to the lignite mine of DHLC, a wholly-owned subsidiary of SWEPCo. In December 2008, we received an order from the LPSC that extended the useful life of the mine for an additional five years, beginning January 1, 2008, which is included in the table above and factored in the estimates noted above for future periods.

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 net income and cash flows.

For discussion of the FERC's November 2008 order on AEP's allocation of off-system sales, see "Allocation of Off-system Sales Margins" section within "FERC Rate Matters".

Ohio Rate Matters

Ohio Electric Security Plan Filings

In April 2008, the Ohio legislature passed Senate Bill 221, which amended the restructuring law effective July 31, 2008 and required electric utilities to adjust their rates by filing an Electric Security Plan (ESP). Electric utilities could include a fuel cost recovery mechanism (FCR) in their ESP filing. Electric utilities also had an option to file a Market Rate Offer (MRO) for generation pricing. An MRO, from the date of its commencement, would have transitioned CSPCo and OPCo to full market rates no sooner than six years and no later than ten years after the PUCO approves an MRO. The PUCO has the authority to approve and/or modify each utility's ESP request. The PUCO is required to approve an ESP if, in the aggregate, the ESP is more favorable to ratepayers than an MRO. Both alternatives involve a "significantly excessive earnings" test (SEET) based on what public companies, including other utilities with similar risk profiles, earn on equity.

In July 2008, within the parameters of the ESPs, CSPCo and OPCo filed with the PUCO to establish rates for 2009 through 2011. CSPCo and OPCo did not file an optional MRO. CSPCo's and OPCo's ESP filings requested an annual rate increase for 2009 through 2011 that would not exceed approximately 15% per year. A significant portion of the requested ESP increases resulted from the implementation of a FCR that primarily includes fuel costs, purchased power costs, consumables such as urea, other variable production costs and gains and losses on sales of emission allowances. The FCR is proposed to be phased into customer bills over the three-year period from 2009 through 2011 and recovered with a weighted average cost of capital carrying cost deferral over seven years from 2012 through 2018. If the ESPs are approved as filed, effective with the implementation of the ESPs, CSPCo and OPCo will defer fuel cost over/under-recoveries and related carrying costs, including amounts unrecovered through the phase in period, for future recovery.

In addition to the FCR, the requested ESP increases would also recover incremental carrying costs associated with environmental costs, Provider of Last Resort (POLR) charges to compensate for the risk of customers changing electric suppliers, automatic increases for distribution reliability costs and for unexpected non-fuel generation costs. The filings also include recovery for programs for smart metering initiatives, economic development, mandated energy efficiency, renewable resources and peak demand reduction programs.

Within the ESP requests, CSPCo and OPCo would also recover existing regulatory assets of $47 million and $39 million, respectively, for customer choice implementation and line extension carrying costs incurred through December 2008. In addition, CSPCo and OPCo would recover related unrecorded equity carrying costs of $31 million and $23 million, respectively, through December 2008. The PUCO had previously issued orders allowing deferral of these costs. Such costs would be recovered over an 8-year period beginning January 2011. If the PUCO does not approve recovery of these regulatory assets in this or some future proceeding, it would have an adverse effect on future net income and cash flows.

Hearings were held in November and December 2008. Many intervenors filed opposing testimony. CSPCo and OPCo requested retroactive application of the new rates, including the FCR, back to the start of the January 2009 billing cycle upon approval of the ESPs. The RSP rates were effective for the years ended December 31, 2006, 2007 and 2008 under which CSPCo and OPCo had three annual generation rate increases of 3% and 7%, respectively. The RSP also allowed additional annual generation rate increases of up to an average of 4% per year to recover new governmentally-mandated costs. In January 2009, CSPCo and OPCo filed an application requesting the PUCO to authorize deferred fuel accounting beginning January 1, 2009. A motion to dismiss the application has been filed by Ohio Partners for Affordable Energy, while the Ohio Consumers' Counsel has filed comments opposing the application. The PUCO ordered that CSPCo and OPCo continue using their current RSP rates until the PUCO issues a ruling on the ESPs or the end of the March 2009 billing cycle, whichever comes first. Management is unable to predict the financial statement impact of the restructuring legislation until the PUCO acts on specific proposals made by CSPCo and OPCo in their ESPs. CSPCo and OPCo anticipate a final order from the PUCO during the first quarter of 2009.

2008 Generation Rider and Transmission Rider Rate Settlement

On January 30, 2008, the PUCO approved a settlement agreement, among CSPCo, OPCo and other parties, under the additional average 4% generation rate increase and transmission cost recovery rider (TCRR) provisions of the RSP. The increase was due to additional governmentally-mandated costs including incremental environmental costs. Under the settlement, the PUCO also approved recovery through the TCRR of 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 during the first quarter of 2008 of $12 million and $14 million, respectively, related to the future recovery of increased PJM billings previously expensed from June 2007 to December 2007 for transmission line losses. The PUCO also approved a credit applied to the TCRR of $10 million for OPCo and $8 million for CSPCo for a reduction in PJM net congestion costs. To the extent that collections for the TCRR recoveries are under/over actual net costs, CSPCo and OPCo will defer the difference as a regulatory asset or regulatory liability and adjust future customer billings to reflect actual costs, including carrying costs on the deferral. In addition, the PUCO approved recoveries through generation rates of environmental costs and related carrying costs of $29 million for CSPCo and $5 million for OPCo. These RSP rate adjustments were implemented in February 2008. The TCRR continues in CSPCo's and OPCo's proposed ESPs to provide for the recovery of PJM related costs.

2009 Generation Rider and Transmission Rider

In October 2008, CSPCo and OPCo filed an application to update the TCRR. The application requested an average decrease of 3% for CSPCo and an average increase of 7% for OPCo, including under recoveries from the prior year and related carrying charges. Based on the requests, CSPCo's annual revenues would decrease approximately $5 million and OPCo's annual revenues would increase approximately $13 million.

In December 2008, the PUCO issued a final order approving the application with certain modifications. First, the rate to calculate carrying costs will change from using a current weighted average cost of capital rate (WACC), which includes a return on equity and a gross up for income taxes, to a long-term debt rate. CSPCo's and OPCo's approved long-term debt rates were 5.73% and 5.71%, respectively. In addition, the TCRR application eliminated the fuel-related credit which had been applied against the PJM transmission marginal line loss since CSPCo's and OPCo's proposed fuel adjustment clause in the filing of the ESP includes this credit. The new TCRR became effective with the January 2009 billing cycle.

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 generation rates which may be a market-based standard service offer price for generation and the expected higher 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 allow CSPCo and OPCo 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 pre-construction costs and incurred $11 million in pre-construction costs. As a result, CSPCo and OPCo each established a net regulatory liability of approximately $1 million.

The order also provided that 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 cost recoveries 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 2006, intervenors filed four separate appeals of the PUCO's order in the IGCC proceeding. In March 2008, the Ohio Supreme Court issued its opinion affirming in part, and reversing in part the PUCO's order and remanded the matter back to the PUCO. The Ohio Supreme Court held that while there could be an opportunity under existing law to recover a portion of the IGCC costs in distribution rates, traditional rate making procedures would apply to the recoverable portion. The Ohio Supreme Court did not address the matter of refunding the Phase 1 cost recovery and declined to create an exception to its precedent of denying claims for refund of past recoveries from approved orders of the PUCO. In September 2008, the Ohio Consumers' Counsel filed a motion with the PUCO requesting all Phase 1 costs be refunded to Ohio ratepayers with interest because the Ohio Supreme Court invalidated the underlying foundation for the Phase 1 recovery. In October 2008, CSPCo and OPCo filed a motion with the PUCO that argued the Ohio Consumers' Counsel's motion was without legal merit and contrary to past precedent.

In January 2009, a PUCO Attorney Examiner issued an order that CSPCo and OPCo file a detailed statement outlining the status of the construction of the IGCC plant, including whether CSPCo and OPCo are engaged in a continuous course of construction on the IGCC plant. In February 2009, CSPCo and OPCo filed a statement that CSPCo and OPCo have not commenced construction of the IGCC plant and believe there exist real statutory barriers to the construction of any new base load generation in Ohio, including IGCC plants. The statement also indicated that while construction on the IGCC plant might not begin by June 2011, changes in circumstances could result in the commencement of construction on a continuous course by that time.

As of December 2007 the estimate cost to build the IGCC plant was $2.7 billion which has continued to increase significantly. Management continues to pursue the ultimate construction of the IGCC plant. However, CSPCo and OPCo will not start construction of the IGCC plant until sufficient assurance of regulatory cost recovery exists.

If CSPCo and OPCo were required to refund the $24 million collected and those costs were not recoverable in another jurisdiction in connection with the construction of an IGCC plant, it would have an adverse effect on future net income and cash flows. Management cannot predict the outcome of the cost recovery litigation concerning the Ohio IGCC plant or what, if any effect, the litigation will have on future net income and cash flows.

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 and the difference was recovered through the amortization of an existing $57 million ($15 million for CSPCo and $42 million for OPCo) regulatory liability related to excess deferred state taxes resulting from the phase-out of an Ohio franchise tax recorded in 2005. During 2007, CSPCo and OPCo each amortized $7 million of this regulatory liability to increase income. During 2008, CSPCo and OPCo each amortized $21.5 million of this regulatory liability to income based on PUCO approved market prices. The settlement agreement required CSPCo and OPCo to exhaust the $57 million regulatory liability. Therefore, CSPCo reimbursed OPCo for $13.5 million of OPCo's unamortized regulatory liability. The previously approved 2007 price of $47.69 per MWH was used through November 2008 when the PUCO approved a 2008 price of $53.03 per MWH. The additional amortization recorded in December 2008 of $11 million each for CSPCo and OPCo related to the increase in the 2008 PUCO approved market price for the period January 2008 through November 2008. As of December 31, 2008, the regulatory liability was fully amortized.

In December 2008, CSPCo, OPCo and Ormet filed an application with the PUCO for approval of an interim arrangement governing the provision of generation service to Ormet. The arrangement would remain in effect and expire upon the effective date of CSPCo's and OPCo's new ESP rates and the effective date of a new arrangement between Ormet and CSPCo/OPCo approved by the PUCO. Under the interim arrangement, Ormet would pay the applicable generation tariff rates and riders. CSPCo and OPCo sought to defer as a regulatory asset beginning in 2009 the difference between the PUCO approved 2008 market price and the applicable generation tariff rates and riders. CSPCo and OPCo propose to recover the deferral through the fuel adjustment clause mechanism they proposed in the ESP proceeding. In January 2009, the PUCO approved the application as an interim arrangement. Although the PUCO did not address recovery in this order, it is expected to be resolved in the pending ESP proceedings. In February 2009, an intervenor filed an application for rehearing of the PUCO's interim arrangement approval. In February 2009, Ormet filed an application with the PUCO for approval of a proposed power contract for 2009 through 2018. Ormet proposed that it pay varying amounts based on certain conditions, including the price of aluminum. The difference between the amounts paid by Ormet and the otherwise applicable PUCO tariff rate would be either collected from or refunded to CSPCo's and OPCo's retail customers.

Hurricane Ike

In September 2008, the service territories of CSPCo and OPCo were impacted by strong winds from the remnants of Hurricane Ike. Under the RSP, CSPCo and OPCo could seek a distribution rate adjustment to recover incremental distribution expenses related to major storm service restoration efforts. In September 2008, CSPCo and OPCo established regulatory assets of $17 million and $10 million, respectively. In December 2008, CSPCo and OPCo filed with the PUCO a request to establish the regulatory assets, plus carrying costs using CSPCo's and OPCo's weighted average cost of capital carrying charge rates. In December 2008, the PUCO subsequently approved the establishment of the regulatory assets but authorized CSPCo and OPCo to record a long-term debt only carrying cost on the regulatory asset. In its order approving the deferrals, the PUCO stated that recovery would be determined in CSPCo's and OPCo's future filings.

In December 2008, the Consumers for Reliable Electricity in Ohio filed a request with the PUCO asking for an investigation into the service reliability of Ohio's investor-owned electric utilities, including CSPCo and OPCo. The investigation request includes the widespread outages caused by the September 2008 wind storm. CSPCo and OPCo filed a response asking the PUCO to deny the request.

As a result of the past favorable treatment of storm restoration costs and the RSP provisions, which were in effect when the storm occurred and the filings made, management believes the recovery of the regulatory assets is probable. However, if these regulatory assets are not recovered, it would have an adverse effect on future net income and cash flows.

Texas Rate Matters

TEXAS RESTRUCTURING

Texas Restructuring Appeals

Pursuant to PUCT orders, TCC securitized net recoverable stranded generation costs of $2.5 billion and is recovering the principal and interest on the securitization bonds through the end of 2020. TCC refunded net other true-up regulatory liabilities of $375 million during the period October 2006 through June 2008 via a CTC credit rate rider. Although earnings were not affected by this CTC refund, cash flow was adversely impacted for 2008, 2007 and 2006 by $75 million, $238 million and $69 million, respectively. 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 were:

- 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.
- 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 orders seeking to further reduce TCC's true-up recoveries.

In March 2007, the Texas District Court judge hearing the appeals 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 and remanded this matter to the PUCT for further consideration. The District Court judge also determined that the PUCT improperly reduced TCC's net stranded plant costs for commercial unreasonableness.

TCC, the PUCT and intervenors appealed the District Court decision to the Texas Court of Appeals. In May 2008, the Texas Court of Appeals affirmed the District Court decision in all but two major respects. It reversed the District Court's unfavorable decision which found that the PUCT erred by applying an invalid rule to determine the carrying cost rate. It also determined that the PUCT erred by not reducing stranded costs by the "excess earnings" that had already been refunded to affiliated retail electric providers. Management does not believe that TCC will be adversely affected by the Court of Appeals ruling on excess earning based upon the reasons discussed in the "TCC Excess Earnings" section below. The favorable commercial unreasonableness judgment entered by the District Court was not reversed. The Texas Court of Appeals denied intervenors' motion for rehearing. In May 2008, TCC, the PUCT and intervenors filed petitions for review with the Texas Supreme Court. Review is discretionary and the Texas Supreme Court has not determined if it will grant review.

TNC received its final true-up order in May 2005 that resulted in refunds via a CTC which have been completed. Appeals brought by intervenors and TNC of the final true-up order remain pending in state court.

Management cannot predict the outcome of these court proceedings and PUCT remand decisions. If TCC and/or TNC ultimately succeed in its appeals, it could have a material favorable effect on future net income, cash flows and financial condition. If municipal customers and other intervenors succeed in their appeals, it could have a substantial adverse effect on future net income, 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 reduced TCC's securitized stranded costs by certain tax benefits. Subsequent to the reduction, the PUCT allowed TCC to defer $103 million of ordered CTC refunds for other true-up items to negate the securitization reduction. Of the $103 million, $61 million relates to the present value of certain tax benefits applied to reduce the securitization stranded generating assets and $42 million relates to carrying costs. The deferral of the CTC refunds is pending resolution on whether the PUCT's securitization refund is an IRS normalization violation.

Evidence includes a March 2008 IRS issuance of final regulations addressing the normalization requirements for the treatment of Accumulated Deferred Investment Tax Credit (ADITC) and Excess Deferred Federal Income Tax (EDFIT) in a stranded cost determination. Consistent with a Private Letter Ruling TCC received in 2006, the regulations clearly state that TCC will sustain a normalization violation if the PUCT orders TCC to flow the tax benefits to customers as part of the stranded cost true-up. TCC notified the PUCT that the final regulations were issued and the PUCT made its request to the court. In May 2008, as requested by the PUCT, the Texas Court of Appeals ordered a remand of the tax normalization issue for the consideration of this additional evidence.

TCC expects that the PUCT will allow TCC to retain these amounts. This will have a favorable effect on future net income and cash flows as TCC will be free to amortize the deferred ADITC and EDFIT tax benefits due to the sale of the generating plants that generated the tax benefits. Since management expects that the PUCT will allow TCC to retain the deferred CTC refund amounts in order to avoid an IRS normalization violation, management has not accrued any related interest expense for refunds of these amounts. If accrued, management estimates interest expense would have been approximately $4 million higher for the period July 2008 through December 2008 based on a CTC interest rate of 7.5%.

If the PUCT orders TCC to return the tax benefits to customers, thereby causing TCC to violate the IRS' normalization regulations, it could result in TCC's repayment to the IRS, under the normalization rules, of ADITC on all property, including transmission and distribution property. This amount approximates $103 million as of December 31, 2008. It could also lead to a loss of TCC's right to claim accelerated tax depreciation in future tax returns. If TCC is required to repay to the IRS its ADITC and is also required to refund ADITC to customers, it would have an unfavorable effect on future net income and cash flows. 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. Management intends to continue to work with the PUCT to favorably resolve the issue and avoid the adverse effects of a normalization violation on future net income, cash flows and financial condition.

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 to the REPs in lieu of reducing stranded cost recoveries from REPs in the True-up Proceeding. It is possible that TCC's stranded cost recovery, which is currently on appeal, may be affected by a PUCT remedy.

In May 2008, the Texas Court of Appeals issued a decision in TCC's True-up Proceeding determining that even though excess earnings had been previously refunded to REPs, TCC 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 of $55 million representing a receivable from the REPs for prior excess earnings refunds made to them by TCC. 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 net income and cash flows. AEP sold its affiliate REPs in December 2002. While AEP owned the affiliate REPs, TCC refunded $11 million of excess earnings to the affiliate REPs. Management cannot predict the outcome of the excess earnings remand and whether it would have an adverse effect on future net income and cash flows.

OTHER TEXAS RATE MATTERS

Hurricanes Dolly and Ike

In July and September 2008, TCC's service territory in south Texas was hit by Hurricanes Dolly and Ike, respectively. TCC incurred $23 million and $2 million in incremental maintenance costs related to service restoration efforts for Hurricanes Dolly and Ike, respectively. TCC has a PUCT approved catastrophe reserve which permits TCC to collect $1.3 million on an annual basis with authority to continue the collection until the catastrophe reserve reaches $13 million. Any incremental storm-related maintenance costs can be charged against the catastrophe reserve if the total incremental maintenance costs for a storm exceed $500 thousand. In June 2008, prior to these hurricanes, TCC had approximately $2 million recorded in the catastrophe reserve account. Therefore, TCC established a net regulatory asset for $23 million.

Under Texas law and as previously approved by the PUCT in prior base rate cases, the regulatory asset will be included in rate base in the next base rate filing. At that time, TCC will evaluate the existing catastrophe reserve amounts and review potential future events to determine the appropriate funding level to request to both recover the regulatory asset and fund a reserve for future storms.

ETT

In December 2007, TCC contributed $70 million of transmission facilities to ETT, an AEP joint venture accounted for using the equity method. The PUCT approved ETT's initial rates, its request for a transfer of facilities and a certificate of convenience and necessity to operate as a stand alone transmission utility in the ERCOT region. ETT was allowed a 9.96% after tax return on equity rate in those approvals. In 2008, intervenors filed a notice of appeal to the Travis County District Court. In October 2008, the court ruled that the PUCT exceeded its authority by approving ETT's application as a stand alone transmission utility without a service area under the wrong section of the statute. Management believes that ruling is incorrect. Moreover, ETT provided evidence in its application that ETT complied with what the court determined was the proper section of the statute. In January 2009, ETT and the PUCT filed appeals to the Texas Court of Appeals. As of December 31, 2008, AEP's net investment in ETT was $15 million. In January 2009, TCC sold $60 million of transmission facilities to ETT. See "Electric Transmission Texas LLC (ETT)" section of Note 7. Depending upon the ultimate outcome of the appeals and any resulting remands, TCC may be required to reacquire transferred assets and projects under construction by ETT.

ETT, TCC and TNC are involved in transactions relating to the transfer to ETT of other transmission assets, which are in various stages of review and approval. In September 2008, ETT and a group of other Texas transmission providers filed a comprehensive plan with the PUCT for completion of the Competitive Renewable Energy Zone (CREZ) initiative. The CREZ initiative is the development of 2,400 miles of new transmission lines to transport electricity from 18,000 megawatts of planned wind farm capacity in west Texas to rapidly growing cities in eastern Texas. In January 2009, the PUCT announced its decision to authorize ETT to construct CREZ related projects. ETT has estimated that the PUCT's decision authorizes ETT to construct $750 million to $850 million of new transmission assets.

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 Base Rate Filing

In May 2008, APCo filed an application with the Virginia SCC to increase its base rates by $208 million on an annual basis. The proposed revenue requirement reflected a return on equity of 11.75%. As permitted under Virginia law, APCo implemented these new base rates, subject to refund, effective October 28, 2008.

In October 2008, APCo submitted a $168 million settlement agreement to the Virginia SCC which was accepted by most parties. The $168 million settlement agreement revenue requirement was determined using a 10.2% return on equity and reflected the Virginia SCC staff's recommended increase as adjusted.

In November 2008, the Virginia SCC issued a final order approving the settlement agreement which increased APCo's annual base revenues by $168 million. The new authorized rates were implemented in December 2008, retroactive to October 28, 2008. APCo made customer refunds with interest in January 2009 for the difference between the interim rates and the approved rates.

Virginia E&R Costs Recovery Filing

In May 2008, APCo filed a request with the Virginia SCC to recover $66 million of its incremental E&R costs incurred for the period of October 2006 to December 2007. In September 2008, a settlement was reached and a stipulation agreement (stipulation) to recover $61 million of costs was submitted to the hearing examiner. In October 2008, the Virginia SCC approved the stipulation which will have a favorable effect on 2009 cash flows of $61 million and on net income for the previously unrecognized equity carrying costs of approximately $11 million.

As of December 31, 2008, APCo has $123 million of deferred Virginia incremental E&R costs (excluding $25 million of unrecognized equity carrying costs). The $123 million consists of $6 million of over recovery of costs collected from the 2008 surcharge, $50 million approved by the Virginia SCC related to APCo's May 2008 E&R filing to be recovered in 2009, and $79 million, representing costs deferred in 2008, to be included in the 2009 E&R filing, to be collected in 2010.

If the Virginia SCC were to disallow a material portion of APCo's 2008 deferral of incremental E&R costs, it would have an adverse effect on future net income and cash flows.

Virginia Fuel Clause Filing

In July 2008, APCo initiated a fuel factor proceeding with the Virginia SCC and requested an annualized increase of $132 million effective September 1, 2008. The increase primarily related to increases in coal costs. In October 2008, the Virginia SCC ordered an annualized increase of $117 million based on differences in estimated future costs and inclusive of PJM transmission marginal line losses, subject to subsequent true-up to actual.

APCo's Filings for an IGCC Plant

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

In June 2007, APCo sought pre-approval with the WVPSC for a surcharge rate mechanism to provide for the timely recovery of 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. In March 2008, the WVPSC granted APCo the CPCN to build the plant and approved the requested cost recovery. In March 2008, various intervenors filed petitions with the WVPSC to reconsider the order. No action has been taken on the requests for rehearing.

In July 2007, APCo filed a request with the Virginia SCC for a rate adjustment clause to recover initial costs associated with a proposed IGCC plant. The filing requested recovery of an estimated $45 million over twelve months beginning January 1, 2009. The $45 million included a return on projected CWIP and development, design and planning pre-construction costs incurred from July 1, 2007 through December 31, 2009. APCo also requested authorization to defer a carrying cost on deferred pre-construction costs incurred beginning July 1, 2007 until such costs are recovered.

The Virginia SCC issued an order in April 2008 denying APCo's requests, in part, upon its finding that the estimated cost of the plant was uncertain and may escalate. The Virginia SCC also expressed concern that the $2.2 billion estimated cost did not include a retrofitting of carbon capture and sequestration facilities. In July 2008, based on the unfavorable order received in Virginia, the WVPSC issued a notice seeking comments from parties on how the WVPSC should proceed. Comments were filed by various parties, including APCo, but the WVPSC has not taken any action.

Through December 31, 2008, APCo deferred for future recovery pre-construction IGCC costs of approximately $9 million applicable to the West Virginia jurisdiction, approximately $2 million applicable to the FERC jurisdiction and approximately $9 million allocated to the Virginia jurisdiction.

In July 2008, the IRS allocated $134 million in future tax credits to APCo for the planned IGCC plant contingent upon the commencement of construction, qualifying expense being incurred and certification of the IGCC plant prior to July 2010.

Although management continues to pursue the construction of the IGCC plant, APCo will not start construction of the IGCC plant until sufficient assurance of cost recovery exists. If the plant is cancelled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs. If the plant is cancelled and if the deferred costs are not recoverable, it would have an adverse effect on future net income and cash flows.

Mountaineer Carbon Capture Project

In January 2008, APCo and ALSTOM Power Inc. (Alstom), an unrelated third party, entered into an agreement to jointly construct a CO_2 capture demonstration facility. APCo and Alstom will each own part of the CO_2 capture facility. APCo will also construct and own the necessary facilities to store the CO_2. RWE AG, a German electric power and natural gas public utility, is participating in the evaluation of the commercial and technical feasibility of taking captured CO_2 from the flue gas stream and storing it in deep geologic formations. APCo's estimated cost for its share of the facilities is $76 million. Through December 31, 2008, APCo incurred $29 million in capitalized project costs which are included in Regulatory Assets. APCo is earning a return on the capitalized project costs incurred through June 30, 2008, as a result of the base rate case settlement approved by the Virginia SCC in November 2008. See the "Virginia Base Rate Filing" section above. APCo plans to seek recovery for the CO_2 capture and storage project costs in its next Virginia and West Virginia base rate filings which are expected to be filed in 2009. If a significant portion of the deferred project costs are excluded from base rates and ultimately disallowed in future Virginia or West Virginia rate proceedings, it could have an adverse effect on future net income and cash flows.

West Virginia Rate Matters

APCo's and WPCo's 2008 Expanded Net Energy Cost (ENEC) Filing

In February 2008, APCo and WPCo filed with the WVPSC for an increase of approximately $156 million including a $135 million increase in the ENEC, a $17 million increase in construction cost surcharges and $4 million of reliability expenditures, to become effective July 2008. In June 2008, the WVPSC issued an order approving a joint stipulation and settlement agreement granting rate increases, effective July 2008, of approximately $106 million based on differences in estimated future costs, including an $88 million increase in the ENEC, a $14 million increase in construction cost surcharges and $4 million of reliability expenditures. The ENEC is an expanded form of a fuel clause mechanism, which includes all energy-related costs including fuel, purchased power expenses, off-system sales credits, PJM costs associated with transmission line losses due to the implementation by PJM transmission marginal line loss pricing and other energy/transmission items.

The ENEC and reliability surcharges are subject to a true-up to actual costs. Therefore, there should be no earnings effect if actual costs exceed the recoveries due to the deferral of any under-recovery of costs. The construction cost is not subject to a true-up to actual costs and could impact future net income and cash flows if actual costs exceed the amounts approved for recovery.

APCo's Filings for an IGCC Plant

See "APCo's Filings for an IGCC Plant" section within "Virginia Rate Matters" for disclosure.

Mountaineer Carbon Capture Project

See "Mountaineer Carbon Capture Project" section within "Virginia Rate Matters" for disclosure.

Indiana Rate Matters

Indiana Base Rate Filing

In a January 2008 filing with the IURC, updated in the second quarter of 2008, I&M requested an increase in its Indiana base rates of $80 million including a return on equity of 11.5%. The base rate increase included a $69 million annual reduction in depreciation expense previously approved by the IURC and implemented for accounting purposes effective June 2007. The filing also requested trackers for certain variable components of the cost of service including recently increased PJM costs associated with transmission line losses due to the implementation of PJM transmission marginal line loss pricing and other RTO costs, reliability enhancement costs, demand side management/energy efficiency costs, off-system sales margins and environmental compliance costs. The trackers would initially increase annual revenues by an additional $45 million. I&M proposes to share with customers, through a proposed tracker, 50% of off-system sales margins initially estimated to be $96 million annually with a guaranteed credit to customers of $20 million.

In December 2008, I&M and all of the intervenors jointly filed a settlement agreement with the IURC proposing to resolve all of the issues in the case. The settlement agreement included a $22 million increase in revenue from base rates with an authorized return on equity of 10.5% and a $22 million initial increase in tracker revenue. The agreement also establishes an off-system sales sharing mechanism and trackers for PJM, net emission allowance, and DSM costs, among other provisions which include continued funding for the eventual decommissioning of the Cook Nuclear Plant. I&M anticipates a final order from the IURC during the first quarter of 2009.

Rockport and Tanners Creek

In January 2009, I&M filed a petition with the IURC requesting approval of a Certificate of Public Convenience and Necessity (CPCN) to use advanced coal technology which would allow I&M to reduce airborne emissions of NO_x and mercury from existing coal-fired steam electric generating units at the Rockport and Tanners Creek Plants. In addition, the petition is requesting approval to construct and recover the costs of selective non-catalytic reduction (SNCR) systems at the Tanners Creek plant and to recover the costs of activated carbon injection (ACI) systems on both generating units at the Rockport plant. I&M is requesting to depreciate the ACI systems over a period of 10 years and the SNCR systems over the remaining useful life of the Tanners Creek generating units. I&M requested the IURC to approve a rate adjustment mechanism of unrecovered carrying costs during construction and a return on investment, depreciation expense and operation and maintenance costs, including consumables and new emission allowance costs, once the projects are placed in service. I&M also requested the IURC to authorize deferral of costs and carrying costs until such costs are recognized in the rate adjustment mechanism. The IURC has not issued a procedural schedule at this time for this petition. Management is unable to predict the outcome of this petition.

Indiana Fuel Clause Filing

In January 2009, I&M filed with the IURC an application to increase its fuel adjustment charge by approximately $53 million for April through September 2009. The filing included an under-recovery for the period ended November 2008, mainly as a result of the extended outage of the Cook Unit 1 due to damage to the main turbine and generator and increased coal prices, and a projection for the future period of fuel costs including Cook Unit 1 replacement power fuel clause costs. The filing also included an adjustment to reduce the incremental fuel cost of replacement power with a portion of the insurance proceeds from the Cook Unit 1 accidental outage policy. See "Cook Plant Unit 1 Fire and Shutdown" section within the "Commitment, Guarantees and Contingencies" footnote for further details. I&M reached an agreement in February 2009 with intervenors to collect the under-recovery over twelve months instead of over six months as proposed. Under the agreement, the fuel factor will go into effect subject to refund and a subdocket will be established to consider issues relating to the Cook Unit 1 outage and I&M's fuel procurement practices. A decision from the IURC is still pending.

Michigan Rate Matters

Michigan Restructuring

Although customer choice commenced for I&M's Michigan customers on January 1, 2002, I&M's rates for generation in Michigan continued to be cost-based regulated because none of I&M's customers elected to change suppliers and no alternative electric suppliers were registered to compete in I&M's Michigan service territory. In October 2008, the Governor of Michigan signed legislation to limit customer choice load to no more than 10% of the annual retail load for the preceding calendar year and to require the remaining 90% of annual retail load to be phased into cost-based rates. The new legislation also requires utilities to meet certain energy efficiency and renewable portfolio standards and permits cost recovery of meeting those standards. Management continues to conclude that I&M's rates for generation in Michigan are cost-based regulated and that I&M can practice regulatory accounting.

Kentucky Rate Matters

2008 Fuel Cost Reconciliation

In January 2008, KPCo filed its semi-annual fuel cost reconciliation covering the period May 2007 through October 2007. As part of this filing, KPCo sought recovery of incremental costs associated with transmission line losses billed by PJM since June 2007 due to PJM's implementation of PJM transmission marginal line loss pricing. KPCo expensed these incremental PJM costs associated with transmission line losses pending a determination that they are recoverable through the Kentucky fuel clause. In June 2008, the KPSC issued an order approving KPCo's semi-annual fuel cost reconciliation filing and recovery of incremental costs associated with transmission line losses billed by PJM. For the year ended December 31, 2008, KPCo recorded $20 million of income and the related Regulatory Asset for Under-Recovered Fuel Costs for transmission line losses incurred from June 2007 through December 2008 of which $7 million related to 2007.

Oklahoma Rate Matters

PSO Fuel and Purchased Power

2006 and Prior Fuel and Purchased Power

Proceedings addressing PSO's historic fuel costs through 2006 remain open at the OCC due to the issue of the allocation of off-system sales margins among the AEP operating companies in accordance with a FERC-approved allocation agreement. For further discussion and estimated effect on net income see "Allocation of Off-system Sales Margins" section within "FERC Rate Matters".

In 2002, PSO under-recovered $42 million of fuel costs resulting from a reallocation among AEP West companies of purchased power costs for periods prior to 2002. PSO recovered the $42 million during the period June 2007 through May 2008. In June 2008, the Oklahoma Industrial Energy Consumers (OIEC) appealed an ALJ recommendation that allowed PSO to retain the $42 million from ratepayers. The OIEC requested that PSO be required to refund the $42 million through its fuel clause. In August 2008, the OCC heard the OIEC appeal and a decision is pending.

2007 Fuel and Purchased Power

In September 2008, the OCC initiated a review of PSO's generation, purchased power and fuel procurement processes and costs for 2007. Management cannot predict the outcome of the pending fuel and purchased power cost recovery filings. However, PSO believes its fuel and purchased power procurement practices and costs were prudent and properly incurred and therefore are legally recoverable.

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 have owned 50% of the new unit. OG&E and PSO requested pre-approval to construct the coal-fired Red Rock Generating Facility (Red Rock) 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 rejected the ALJ's recommendation and denied PSO's and OG&E's applications for construction pre-approval. The OCC stated that PSO failed to fully study other alternatives to a coal-fired plant. Since PSO and OG&E could not obtain pre-approval to build Red Rock, PSO and OG&E cancelled the third party construction contract and their joint venture development contract.

In December 2007, PSO filed an application at the OCC requesting recovery of $21 million in pre-construction costs and contract cancellation fees associated with Red Rock. In March 2008, PSO and all other parties in this docket signed a settlement agreement that provided for recovery of $11 million of Red Rock pre-construction costs and carrying costs at PSO's AFUDC rate beginning in March 2008 and continuing until the $11 million is included in base rates in PSO's next base rate case. PSO will recover the costs over the expected life of the peaking facilities at the Southwestern Station, and include the costs in rate base in its next base rate filing. The OCC approved the settlement in May 2008. As a result of the settlement, PSO wrote off $10 million of its deferred pre-construction costs/cancellation fees in the first quarter of 2008. The remaining balance of $11 million was recorded as a regulatory asset. In July 2008, PSO filed a base rate case which included $11 million of deferred Red Rock costs plus carrying charges at PSO's AFUDC rate beginning in March 2008. In January 2009, the OCC approved the base rate case. See "2008 Oklahoma Base Rate Filing" section below.

Oklahoma 2007 Ice Storms

In January and December 2007, PSO incurred maintenance expenses for two large ice storms. Prior to December 2007, PSO filed with the OCC requesting recovery of the maintenance expenses related to the January 2007 service restoration efforts. PSO proposed in its application to establish a regulatory asset to defer the previously expensed ice storm restoration costs and to offset the regulatory asset with gains from the sale of excess SO_2 emission allowances.

In February 2008, PSO entered into a settlement agreement for recovery of ice storm restoration costs from both ice storms. In March 2008, the OCC approved the settlement agreement subject to a final audit. Therefore, in March 2008, PSO recorded a regulatory asset for the previously expensed ice storm maintenance costs. In October 2008, PSO received final approval to recover $74 million of ice storm costs. PSO has applied and will continue to apply proceeds from sale of excess SO_2 emission allowances to reduce the regulatory asset. The estimated net balance that is not recovered from the sale of emission allowances will be amortized and recovered through a rider over a period of five years which began in November 2008. The rider will ultimately be trued-up to recover the entire $74 million regulatory asset. The regulatory asset earns a return of 10.92% until fully recovered.

2008 Oklahoma Base Rate Filing

In July 2008, PSO filed an application with the OCC to increase its base rates by $133 million (later adjusted to $127 million) on an annual basis. PSO has been recovering costs related to new peaking units recently placed into service through a Generation Cost Recovery Rider (GCRR). Subsequent to implementation of the new base rates, the GCRR will terminate and PSO will recover these costs through the new base rates. Therefore, PSO's net annual requested increase in total revenues was actually $117 million (later adjusted to $111 million). The proposed revenue requirement reflected a return on equity of 11.25%.

In January 2009, the OCC issued a final order approving an $81 million increase in PSO's non-fuel base revenues and a 10.5% return on equity. The rate increase includes a $59 million increase in base rates and a $22 million increase for costs to be recovered through riders outside of base rates. The $22 million increase includes $14 million for purchase power capacity costs and $8 million for the recovery of carrying costs associated with PSO's program to convert overhead distribution lines to underground service. The $8 million recovery of carrying costs associated with the overhead to underground conversion program will occur only if PSO makes the required capital expenditures. The final order approved lower depreciation rates and also provides for the deferral of $6 million of generation maintenance expenses to be recovered over a six-year period. This deferral will be recorded in the first quarter of 2009. Additional deferrals were approved for distribution storm costs above or below the amount included in base rates and for certain transmission reliability expenses. The new rates reflecting the final order were implemented with the first billing cycle of February 2009.

In January 2009, PSO and one intervenor filed motions with the OCC to modify its final order. PSO filed an appeal with the Oklahoma Supreme Court challenging an adjustment the OCC made on prepaid pension funding contained within the OCC final order. The OCC subsequently declined to consider the motions to modify. In February 2009, the Oklahoma Attorney General and several intervenors also filed appeals with the Oklahoma Supreme Court raising several issues. If the Attorney General and/or the intervenor's Supreme Court appeals are successful, it could have an adverse effect on future net income and cash flows.

Louisiana Rate Matters

Louisiana Compliance Filing

In connection with SWEPCo's merger related compliance filings, the LPSC approved a settlement agreement in April 2008 that prospectively resolves all issues regarding claims that SWEPCo had over-earned its allowed return. SWEPCo agreed to a formula rate plan (FRP) with a three-year term. Under the plan, beginning in August 2008, rates shall be established to allow SWEPCo to earn an adjusted return on common equity of 10.565%. The adjustments are standard Louisiana rate filing adjustments.

If in the second and third year 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 recovery deferrals for refund or future recovery under this FRP.

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

In addition, the settlement provides for a reduction in generation depreciation rates effective October 2007. SWEPCo deferred as a regulatory liability the effects of the expected depreciation reduction through July 2008. SWEPCo will amortize this 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.

In April 2008, SWEPCo filed the first FRP which would increase its annual Louisiana retail rates by $11 million in August 2008 to earn an adjusted return on common equity of 10.565%. In accordance with the settlement, SWEPCo recorded a $4 million regulatory liability related to the reduction in generation depreciation rates. The amount of the unamortized regulatory liability for the reduction in generation depreciation was $3 million as of December 31, 2008. In August 2008, the LPSC approved the settlement and SWEPCo implemented the FRP rates, subject to refund. No provision for refund has been recorded as SWEPCo believes that the rates as implemented are in compliance with the settlement.

Stall Unit

In May 2006, SWEPCo announced plans to build a new intermediate load, 500 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 to the PUCT, the APSC, the LPSC and the Louisiana Department of Environmental Quality to seek approvals to construct the unit. The Stall Unit is currently estimated to cost $384 million, excluding AFUDC, and is expected to be in-service in mid-2010. The Louisiana Department of Environmental Quality issued an air permit for the Stall unit in March 2008.

In March 2007, the PUCT approved SWEPCo's request for a certificate for the facility based on a prior cost estimate. In July 2008, a Louisiana ALJ issued a recommendation that SWEPCo be authorized to construct, own and operate the Stall Unit and recommended that costs be capped at $445 million (excluding transmission). In October 2008, the LPSC issued a final order effectively approving the ALJ recommendation. In December 2008, SWEPCo submitted an amended filing seeking approval from the APSC to construct the unit. The APSC has established a procedural schedule with a public hearing for April 2009.

If SWEPCo does not receive appropriate authorizations and permits to build the Stall Unit, SWEPCo would seek recovery of the capitalized construction costs including any cancellation fees. As of December 31, 2008, SWEPCo has capitalized construction costs of $252 million (including AFUDC) and has contractual construction commitments of an additional $99 million. As of December 31, 2008, if the plant had been cancelled, cancellation fees of $33 million would have been required in order to terminate the construction commitments. If SWEPCo cancels the plant and cannot recover its capitalized costs, including any cancellation fees, it would have an adverse effect on future net income, cash flows and possibly financial condition.

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 the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas. SWEPCo submitted filings with the APSC, the PUCT and the LPSC seeking certification of the plant. SWEPCo will own 73% of the Turk Plant and will operate the facility. During 2007, SWEPCo signed joint ownership agreements with the Oklahoma Municipal Power Authority (OMPA), the Arkansas Electric Cooperative Corporation (AECC) and the East Texas Electric Cooperative (ETEC) for the remaining 27% of the Turk Plant. The Turk Plant is currently estimated to cost $1.6 billion, excluding AFUDC, with SWEPCo's portion estimated to cost $1.2 billion. If approved on a timely basis, the plant is expected to be in-service in 2012.

In November 2007, the APSC granted approval to build the Turk Plant. Certain landowners filed a notice of appeal to the Arkansas State Court of Appeals. In March 2008, the LPSC approved the application to construct the Turk Plant.

In August 2008, the PUCT issued an order approving the Turk Plant with the following four conditions: (a) the capping of capital costs for the Turk Plant at the previously estimated $1.522 billion projected construction cost, excluding AFUDC, (b) capping CO_2 emission costs at $28 per ton through the year 2030, (c) holding Texas ratepayers financially harmless from any adverse impact related to the Turk Plant not being fully subscribed to by other utilities or wholesale customers and (d) providing the PUCT all updates, studies, reviews, reports and analyses as previously required under the Louisiana and Arkansas orders. In October 2008, SWEPCo appealed the PUCT's order regarding the two cost cap restrictions. If the cost cap restrictions are upheld and construction or emissions costs exceed the restrictions, it could have a material adverse impact on future net income and cash flows. In October 2008, an intervenor filed an appeal contending that the PUCT's grant of a conditional Certificate of Public Convenience and Necessity for the Turk Plant was not necessary to serve retail customers.

A request to stop pre-construction activities at the site was filed in federal court by Arkansas landowners. In July 2008, the federal court denied the request and the Arkansas landowners appealed the denial to the U.S. Court of Appeals.

In November 2008, SWEPCo received the air permit approval from the Arkansas Department of Environmental Quality and commenced construction. In December 2008, Arkansas landowners filed an appeal with the Arkansas Pollution Control and Ecology Commission (APCEC) which caused construction of the Turk Plant to halt until the APCEC took further action. In December 2008, SWEPCo filed a request with the APCEC to continue construction of the Turk Plant and the APCEC ruled to allow construction to continue while an appeal of the Turk Plant's permit is heard. SWEPCo is also working with the U.S. Army Corps of Engineers for the approval of a wetlands and stream impact permit.

In January 2008 and July 2008, SWEPCo filed Certificate of Environmental Compatibility and Public Need (CECPN) applications with the APSC to construct transmission lines necessary for service from the Turk Plant. Several landowners filed for intervention status and one landowner also contended he should be permitted to re-litigate Turk Plant issues, including the need for the generation. The APSC granted their intervention but denied the request to re-litigate the Turk Plant issues. In June 2008, the landowner filed an appeal to the Arkansas State Court of Appeals requesting to re-litigate Turk Plant issues. SWEPCo responded and the appeal was dismissed. In January 2009, the APSC approved the CECPN applications.

The Arkansas Governor's Commission on Global Warming issued its final report to the Governor in October 2008. The Commission was established to set a global warming pollution reduction goal together with a strategic plan for implementation in Arkansas. The Commission's final report included a recommendation that the Turk Plant employ post combustion carbon capture and storage measures as soon as it starts operating. If legislation is passed as a result of the findings in the Commission's report, it could impact SWEPCo's proposal to build the Turk Plant.

If SWEPCo does not receive appropriate authorizations and permits 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 paid costs. If that occurred, SWEPCo would seek recovery of its capitalized costs including any cancellation fees and joint owner reimbursements. As of December 31, 2008, SWEPCo has capitalized approximately $510 million of expenditures (including AFUDC) and has significant contractual construction commitments for an additional $727 million. As of December 31, 2008, if the plant had been cancelled, SWEPCo would have incurred cancellation fees of $61 million. If the Turk Plant does not receive all necessary approvals on reasonable terms and SWEPCo cannot recover its capitalized costs, including any cancellation fees, it would have an adverse effect on future net income, cash flows and possibly financial condition.

Arkansas Base Rate Filing

In February 2009, SWEPCo filed an application with the APSC for a base rate increase of $25 million based on a requested return on equity of 11.5%. SWEPCo also requested a separate rider to concurrently recover financing costs related to the Stall and Turk generation plants that are currently under construction. A decision is not expected until the fourth quarter of 2009 or the first quarter of 2010.

Stall Unit

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

FERC Rate Matters

Regional 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 at FERC's direction 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 the AEP East companies and ultimately their internal load retail customers to make up the short fall in revenues.

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 should not have been 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.

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, based on advice of legal counsel, 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. AEP and SECA ratepayers have engaged in settlement discussions in an effort to settle the SECA issue. However, if the ALJ's initial decision is upheld in its entirety, it could result in a disallowance of a large portion on any unsettled SECA revenues.

Based on anticipated settlements, the AEP East companies provided reserves for net refunds for current and future SECA settlements totaling $39 million and $5 million in 2006 and 2007, respectively, applicable to a total of $220 million of SECA revenues. In December 2008, an additional settlement agreement was approved by the FERC resulting in the completion of a $2 million settlement applicable to $17 million of SECA revenue. Including this most recent settlement, AEP has completed settlements totaling $9 million applicable to $92 million of SECA revenues. The balance in the reserve for future settlements as of December 2008 was $35 million. In-process settlements total $1 million applicable to $20 million of SECA revenues. In February 2009, the FERC approved the in-process settlements resulting in the completion of a $1 million settlement application to $20 million of SECA revenues.

If the FERC adopts the ALJ's decision and/or AEP cannot settle all of the remaining unsettled claims within the remaining amount reserved for refund, it will have an adverse effect on future net income and cash flows. 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 available reserve of $34 million is adequate to settle the remaining $108 million of contested SECA revenues. However, management cannot predict the ultimate outcome of ongoing settlement discussions or future FERC proceedings or court appeals, if any.

The FERC PJM Regional Transmission Rate Proceeding

With the elimination of T&O rates, the expiration of SECA rates and after considerable administrative litigation at the FERC in which AEP sought to mitigate the effect of the 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 would 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 by PJM. In February 2008, AEP filed a Petition for Review of the FERC orders in this case in the United States Court of Appeals. 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, net income and cash flows.

The AEP East companies filed for and in 2006 obtained increases in their wholesale transmission rates to recover lost revenues previously applied to reduce those rates. AEP has also sought and received retail rate increases in Ohio, Virginia, West Virginia and Kentucky. As a result, AEP is now recovering approximately 80% of the lost T&O transmission revenues. The remaining 20% is being incurred by AEP until it can revise its rates in Indiana and Michigan to recover these lost revenues. AEP received net SECA transmission revenues of $128 million in 2005. I&M requested recovery of its portion of these lost revenues in its Indiana rate filing in January 2008 but does not expect to commence recovering the new rates until early 2009. Future net income and cash flows will continue to be adversely affected in Indiana and Michigan until the remaining 20% of the lost T&O 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 to be effective February 1, 2008. All of the transmission owners in PJM and MISO, with the exception of AEP and one MISO transmission owner, elected to support continuation of 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 argued 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. AEP filed a rehearing request with the FERC in March 2008. In December 2008, the FERC denied AEP's request for rehearing. In February 2009, AEP filed an appeal in the U.S. Court of Appeals. If the court appeal is successful, earnings could benefit for a certain period of time due to regulatory lag until the AEP East companies reduce future retail revenues in their next fuel or base rate proceedings. Management is unable to predict the outcome of this case.

PJM Transmission Formula Rate Filing

In July 2008, AEP filed an application with the FERC to increase its rates for wholesale transmission service within PJM by $63 million annually. The filing seeks to implement a formula rate allowing annual adjustments reflecting future changes in AEP's cost of service. The requested increase would result in a combined increase in annual revenues for the AEP East companies of approximately $9 million from nonaffiliated customers within PJM. The remaining $54 million requested would be billed to the AEP East companies but would be offset by compensation from PJM for use of AEP's transmission facilities so that retail rates for jurisdictions other than Ohio are not affected. Retail rates for CSPCo and OPCo would be increased through the Transmission Cost Recovery Rider (TCRR) totaling approximately $10 million and $12 million, respectively. The TCRR includes a true-up mechanism so CSPCo's and OPCo's net income will not be adversely affected by a FERC ordered transmission rate increase. AEP requested an effective date of October 1, 2008. In September 2008, the FERC issued an order conditionally accepting AEP's proposed formula rate, subject to a compliance filing, suspended the effective date until March 1, 2009 and established a settlement proceeding with an ALJ. In October 2008, AEP began settlement discussions and filed the required compliance filing. Management is unable to predict the outcome of this filing.

Allocation of Off-system Sales Margins

In August 2008, the OCC filed a complaint at the FERC alleging that AEP inappropriately allocated off-system sales margins between the AEP East companies and the AEP West companies and did not properly allocate off-system sales margins within the AEP West companies. The PUCT, the APSC and the Oklahoma Industrial Energy Consumers intervened in this filing. In November 2008, the FERC issued a final order concluding that AEP inappropriately deviated from off-system sales margin allocation methods in the AEP SIA and the CSW Operating Agreement for the period June 2000 through March 2006. The FERC ordered AEP to recalculate and reallocate the off-system sales margins in compliance with the AEP SIA and to have the AEP East companies issue refunds to the AEP West companies. Although the FERC determined that AEP deviated from the CSW Operating Agreement, the FERC determined the allocation methodology to be reasonable. The FERC ordered AEP to submit a revised CSW Operating Agreement for the period June 2000 to March 2006. In December 2008, AEP filed a motion for rehearing and a revised CSW Operating Agreement for the period June 2000 to March 2006. The motion for rehearing is still pending. In January 2009, AEP filed a compliance filing with the FERC and refunded approximately $250 million from the AEP East companies to the AEP West companies. The AEP West companies shared a portion of such revenues with their wholesale and retail customers during this period. In December 2008, the AEP West companies recorded a provision for refund which had a $97 million unfavorable effect on AEP net income. In January 2009, SWEPCo refunded approximately $13 million to FERC wholesale customers. In February 2009, SWEPCo filed a settlement agreement with the PUCT that provides for the Texas retail jurisdiction refund to be made through the fuel clause recovery mechanism. PSO will begin refunding approximately $54 million plus accrued interest to Oklahoma retail customers through the fuel adjustment clause over a 12-month period beginning with the March 2009 billing cycle. TCC and TNC in Texas and SWEPCo in Arkansas and Louisiana will be working with their state commissions to determine the effect the FERC order will have on retail rates. Management believes that the existing provision for refund is adequate to address existing and any future refunds that may result from the FERC order.

The table below lists the respective amounts the AEP East companies and the AEP West companies recorded in December 2008 including the net increase (decrease) to net income for the year ended December 31, 2008:

	Amounts to be (Transferred)/ Received Including Interest	Increase/ (Decrease) to Net Income
AEP East Companies	**(in millions)**	
APCo	$ (77)	$ (50)
I&M	(48)	(32)
OPCo	(62)	(40)
CSPCo	(44)	(28)
KPCo	(19)	(12)
Total – AEP East Companies	(250)	(162)
AEP West Companies		
PSO	$ 72	$ 12
SWEPCo	85	20
TCC	68	23
TNC	25	10
Total – AEP West Companies	250	65
Total – AEP Consolidated	$ -	$ (97)

Management cannot predict the outcome of the requested FERC rehearing proceeding or any future regulatory proceedings but believes our provision regarding future regulatory proceedings is adequate.

5. EFFECTS OF REGULATION

Regulatory assets and liabilities are comprised of the following items:

Regulatory Assets:	December 31, 2008	December 31, 2007	Notes
	(in millions)		
Current Regulatory Asset			
Under-recovered Fuel Costs	$ 284	$ 11	(c) (h)
Noncurrent Regulatory Assets			
SFAS 158 Regulatory Asset (See Note 8)	$ 2,162	$ 659	(a) (g)
SFAS 109 Regulatory Asset, Net (See Note 12)	888	815	(c) (g)
Virginia E&R Costs Recovery (See Note 4)	123	82	(c) (i)
Unamortized Loss on Reacquired Debt	104	108	(b) (l)
Oklahoma 2007 Ice Storms (See Note 4)	62	-	(b) (j)
Customer Choice Deferrals – Ohio (See Note 4)	55	52	(b) (o)
Restructuring Transition Costs – Texas, Ohio and Virginia	38	108	(a) (k)
Line Extension Carrying Costs – Ohio (See Note 4)	31	23	(b) (o)
Mountaineer Carbon Capture Project – Virginia (See Note 4)	29	-	(c) (o)
Hurricane Ike – Ohio (See Note 4)	27	-	(b) (o)
Cook Nuclear Plant Refueling Outage Levelization	25	34	(a) (d)
Hurricanes Dolly and Ike – Texas (See Note 4)	23	-	(b) (o)
Lawton Settlement – Oklahoma	21	32	(b) (i)
Red Rock Generating Facility – Oklahoma (See Note 4)	11	21	(b) (m)
Unrealized Loss on Forward Commitments	-	39	(a) (g)
Other	184	226	(c) (g)
Total Noncurrent Regulatory Assets	$ 3,783	$ 2,199	

Regulatory Liabilities:	December 31, 2008	December 31, 2007	Notes
Current Regulatory Liability			
Over-recovered Fuel Costs (p)	$ 66	$ 64	(c) (h)
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Asset Removal Costs	$ 2,017	$ 1,927	(e)
Deferred Investment Tax Credits	294	311	(c) (n)
Excess ARO for Nuclear Decommissioning Liability (See Note 9)	208	362	(f)
Unrealized Gain on Forward Commitments	91	103	(a) (g)
Deferred State Income Taxes Due to the Phase Out of the Ohio Franchise Tax	-	43	(a) (h)
Other	179	206	(c) (g)
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 2,789	$ 2,952	

(a) Amount does not earn a return.
(b) Amount earns a return.
(c) A portion of this amount earns a return.
(d) Amortized and recovered 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 "Accounting for Asset Retirement Obligations." 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 - 2 years.
(j) Recovery/refund period - 5 years
(k) Recovery/refund period - up to 7 years.
(l) Recovery/refund period - up to 35 years.
(m) Recovery/refund period - 48 years.
(n) Recovery/refund period - up to 78 years.
(o) Recovery method and timing to be determined in future proceedings.
(p) Current Regulatory Liability - Over-recovered Fuel Costs are recorded in 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, EIS, together with and/or in addition to various industry mutual and commercial insurance carriers.

See Note 9 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 an 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 net income, 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. Budgeted construction expenditures for 2009 are $2.6 billion. In addition, we expect to invest approximately $50 million in our transmission joint ventures in 2009. Budgeted 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 purchase fuel, 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 net income, cash flows or financial condition.

The following table summarizes our actual contractual commitments at December 31, 2008:

Contractual Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 3,788	$ 4,832	$ 2,590	$ 7,362	$ 18,572
Energy and Capacity Purchase Contracts (b)	51	73	40	268	432
Construction Contracts for Capital Assets (c)	661	993	613	-	2,267
Total	$ 4,500	$ 5,898	$ 3,243	$ 7,630	$ 21,271

(a) Represents contractual commitments to purchase coal, natural gas and other consumables as fuel for electric generation along with related transportation of the fuel. The longest contract extends to the year 2035. The contracts provide for periodic price adjustments and contain various clauses that would release us from our commitments under certain conditions.
(b) Represents contractual commitments for energy and capacity purchase contracts.
(c) Represents only capital assets that are contractual commitments.

GUARANTEES

We record certain immaterial liabilities for guarantees in accordance with FIN 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." In addition, we adopted FSP SFAS 133-1 and FIN 45-4 "Disclosures about Credit Derivatives and Certain Guarantees: An amendment of FASB Statement No. 133 and FASB Interpretation No. 45; and Clarification of the Effective Date of FASB Statement No. 161" effective December 31, 2008. 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 and debt service reserves. As the Parent, we issued all of these LOCs in our ordinary course of business on behalf of our subsidiaries. At December 31, 2008, the maximum future payments for LOCs issued under the two $1.5 billion credit facilities are $62 million with maturities ranging from March 2009 to March 2010. The two $1.5 billion credit facilities were reduced by Lehman Brothers Holding Inc.'s commitment amount of $46 million following its bankruptcy.

In April 2008, we entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement which were reduced by Lehman Brothers Holdings Inc.'s commitment amount of $23 million and $12 million, respectively, following its bankruptcy. As of December 31, 2008, $372 million of letters of credit were issued by subsidiaries under the 3-year credit agreement to support variable rate Pollution Control Bonds.

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 46R. 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, 2008, SWEPCo has collected approximately $38 million through a rider for final mine closure costs, of which approximately $700 thousand is recorded in Other Current Liabilities, $20 million is recorded in Deferred Credits and Other and $18 million is recorded in Asset Retirement Obligations on our Consolidated Balance Sheets.

Sabine charges SWEPCo, its only customer, all 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 7. These sale agreements include indemnifications with a maximum exposure related to the collective purchase price, which is approximately $1.2 billion. Approximately $1 billion of the maximum exposure relates to the Bank of America (BOA) litigation (see "Enron Bankruptcy" section of this note), of which the probable payment/performance risk is $433 million and is recorded in Deferred Credits and Other on our Consolidated Balance Sheets as of December 31, 2008. The remaining exposure is remote. There are no material liabilities recorded for any indemnifications other than amounts recorded related to the BOA litigation.

Lease Obligations

We lease certain equipment under master lease agreements. See "Master Lease Agreements" and "Railcar Lease" sections of Note 13 for disclosure of 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. Cases with similar allegations against CSPCo, Dayton Power and Light Company (DP&L) and Duke Energy Ohio, Inc. were also filed related to their jointly-owned units.

In 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 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.

In October 2008, the court approved a consent decree for a settlement reached with the Sierra Club in a case involving CSPCo's share of jointly-owned units at the Stuart Station. The Stuart units, operated by DP&L, are equipped with SCR and FGD controls. Under the terms of the settlement, the joint-owners agreed to certain emission targets related to NO_x, SO_2 and PM. They also agreed to make energy efficiency and renewable energy commitments that are conditioned on receiving PUCO approval for recovery of costs. The joint-owners also agreed to forfeit 5,500 SO_2 allowances and provide $300 thousand to a third party organization to establish a solar water heater rebate program. Another case involving a jointly-owned Beckjord unit had a liability trial in 2008. Following the trial, the jury found no liability for claims made against the jointly-owned Beckjord unit. In December 2008, however, the court ordered a new trial in the Beckjord case.

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 proceeding for Beckjord. We are also unable to predict the timing of resolution of these matters. If we do not prevail, 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 or if material penalties are imposed, it would adversely affect our future net income, 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. In April 2008, the parties filed a proposed consent decree to resolve all claims in this case and in the pending appeal of the altered permit for the Welsh Plant. The consent decree requires SWEPCo to install continuous particulate emission monitors at the Welsh Plant, secure 65 MW of renewable energy capacity by 2010, fund $2 million in emission reduction, energy efficiency or environmental mitigation projects by 2012 and pay a portion of plaintiffs' attorneys' fees and costs. The consent decree was entered as a final order in June 2008.

In 2004, the Texas Commission on Environmental Quality (TCEQ) issued a Notice of Enforcement to SWEPCo relating to the Welsh Plant. A permit alteration was issued in March 2007 that clarified or eliminated certain of the permit conditions. In June 2007, TCEQ denied a motion to overturn the permit alteration. The permit alteration was appealed to the Travis County District Court, but was resolved by entry of the consent decree in the federal citizen suit action, and dismissed with prejudice in July 2008. Notice of an administrative settlement of the TCEQ enforcement action was published in June 2008. The settlement requires SWEPCo to pay an administrative penalty of $49 thousand and to fund a supplemental environmental project in the amount of $49 thousand, and resolves all violations alleged by TCEQ. In October 2008, TCEQ approved the settlement.

In February 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 met with the Federal EPA to discuss the alleged violations in March 2008. The Federal EPA did not object to the settlement of similar alleged violations in the federal citizen suit.

We are unable to predict the timing of any future action by the Federal EPA or the effect of such action on our net income, cash flows or financial condition.

Carbon Dioxide 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 CO_2 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 concluded in 2006. In April 2007, the U.S. Supreme Court issued a decision holding that the Federal EPA has authority to regulate emissions of CO_2 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 which we provided in 2007. We believe the actions are without merit and intend to defend against the claims.

Alaskan Villages' Claims

In February 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in federal court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil & gas companies, a coal company, and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. The defendants filed motions to dismiss the action. The motions are pending before the court. We believe the action is 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, 2008, our subsidiaries are named by the Federal EPA as a Potentially Responsible Party (PRP) for six sites for which alleged liability is unresolved. There are nine 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 four sites under state law including the I&M site discussed in the next paragraph. 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 net income.

In March 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. I&M requested remediation proposals from environmental consulting firms. In May 2008, I&M issued a contract to one of the consulting firms. I&M recorded approximately $4 million of expense through December 31, 2008. As the remediation work is completed, I&M's cost may increase. I&M cannot predict the amount of additional cost, if any. At present, our estimates do not anticipate material cleanup costs for this site.

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.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, likely caused by blade failure, which resulted in a fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. The turbine rotors that caused the vibration were installed in 2006 and are within the vendor's warranty period. The warranty provides for the repair or replacement of the turbine rotors if the damage was caused by a defect in materials or workmanship. I&M is working with its insurance company, Nuclear Electric Insurance Limited (NEIL), and its turbine vendor, Siemens, to evaluate the extent of the damage resulting from the incident and the costs to return the unit to service. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately $330 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance and the regulatory process. Our current analysis indicates that with successful repairs and timely parts deliveries, Unit 1 could resume operations as early as September 2009 at reduced power. If the rotors cannot be repaired, replacement of parts will extend the outage into 2010.

The refueling outage for Cook Plant Unit 2, which continues to operate at full power, will take place as scheduled in the spring of 2009. The refueling outage scheduled for the fall of 2009 for Unit 1 is currently being evaluated. Management anticipates that the loss of capacity from Unit 1 will not affect I&M's ability to serve customers due to the existence of sufficient generating capacity in the AEP Power Pool.

I&M maintains property insurance through NEIL with a $1 million deductible. As of December 31, 2008, we recorded $28 million in Prepayments and Other on our Consolidated Balance Sheet representing recoverable amounts under property insurance proceeds. I&M also maintains a separate accidental outage policy with NEIL whereby, after a 12-week deductible period, I&M is entitled to weekly payments of $3.5 million for the first 52 weeks following the deductible period. After the initial 52 weeks of indemnity, the policy pays $2.8 million per week for up to an additional 110 weeks. I&M began receiving payments under the accidental outage policy effective December 15, 2008. If the ultimate costs of the incident are not covered by warranty, insurance or through the regulatory process or if the unit is not returned to service in a reasonable period of time, it could have an adverse impact on net income, cash flows and financial condition.

In January 2009, I&M filed its regular semi-annual fuel filing in Indiana which determines the fuel rate for the period April 2009 through September 2009. I&M filed to provide to customers a portion of the accidental outage insurance proceeds expected during the forecast period. I&M has deferred $9 million of accidental outage insurance proceeds as of December 31, 2008 which is included in Other Current Liabilities on our Consolidated Balance Sheet.

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, 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.

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 pretax gain in January 2008 under Asset Impairments and Other Related Charges on our Consolidated Statements of Income. This settlement related to the Plaquemine Cogeneration Facility, which we impaired and sold in 2006.

Enron Bankruptcy

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 that 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, 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 the Enron bankruptcy proceedings and in federal courts in Texas and New York.

In February 2004, 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 in the bankruptcy 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 representations 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 in Texas 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 in the Southern District of Texas the four counts alleging breach of contract, fraud and negligent misrepresentation. 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 dismissing 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). In August 2008, the court entered a final judgment of $346 million (the original judgment less $1 million BOA would have incurred to remove 55 BCF of natural gas from the Bammel storage facility) and clarified the interest calculation method. We appealed and posted a bond covering the amount of the judgment entered against us. The appeal was briefed during the first quarter of 2009.

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. After recalculation for the final judgment, the liability for the BOA litigation was $433 million and $427 million including interest at December 31, 2008 and 2007, respectively. These liabilities are included in Deferred Credits and Other on our Consolidated Balance Sheets.

Shareholder Lawsuits

In 2002 and 2003, three putative class action lawsuits were filed in Federal District Court, Columbus, Ohio against AEP, certain executives and AEP's 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. In these actions, the plaintiffs sought recovery of an unstated amount of compensatory damages, attorney fees and costs. Two of the three actions were dropped voluntarily by the plaintiffs in those cases. In July 2006, the court entered judgment in the remaining case, denying plaintiff's motion for class certification and dismissing 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. In September 2008, the trial court denied the plaintiff's motion for class certification and ordered briefing on whether the plaintiff may maintain an ERISA claim on behalf of the Plan in the absence of class certification. In October 2008, counsel for the plaintiff filed a motion to intervene on behalf of an individual seeking to intervene as a new plaintiff. We opposed this motion and will 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. In June 2008, we settled all of the cases pending against us in California. The settlements did not impact 2008 earnings due to provisions made in prior periods. We will continue to defend each remaining case where an AEP company is a defendant. We believe the provision we have for the remaining cases is adequate.

Rail Transportation Litigation

In October 2008, the Oklahoma Municipal Power Authority and the Public Utilities Board of the City of Brownsville, Texas, as co-owners of Oklaunion Plant, filed a lawsuit in United States District Court, Western District of Oklahoma against AEP alleging breach of contract and breach of fiduciary duties related to negotiations for rail transportation services for the plant. The plaintiffs allege that AEP assumed the duties of the project manager, PSO, and operated the plant for the project manager and is therefore responsible for the alleged breaches. In December 2008, the court denied our motion to dismiss the case. We intend to vigorously defend against these allegations. We believe a provision recorded in 2008 should be sufficient.

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 to the U.S. Supreme Court. In June 2008, the U.S. Supreme Court affirmed the validity of contractually-agreed rates except in cases of serious harm to the public. The U.S. Supreme Court affirmed the Ninth Circuit's remand on two issues, market manipulation and excessive burden on consumers. The FERC initiated remand procedures and gave the parties time to attempt to settle the issues. We believe a provision recorded in 2008 should be sufficient. 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. Management is unable to predict the outcome of these proceedings or their ultimate impact on future net income and cash flows.

7. ACQUISITIONS, DISPOSITIONS, DISCONTINUED OPERATIONS AND IMPAIRMENTS

ACQUISITIONS

2008

Erlbacher companies (AEP River Operations segment)

In June 2008, AEP River Operations purchased certain barging assets from Missouri Barge Line Company, Missouri Dry Dock and Repair Company and Cape Girardeau Fleeting, Inc. (collectively known as Erlbacher companies) for $35 million. These assets were incorporated into AEP River Operations' business which will diversify its customer base.

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. Lawrenceburg 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 agreement.

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 $78 million and $3 million in construction costs (excluding AFUDC) at the Dresden Plant in 2008 and 2007, respectively, and expects to incur approximately $142 million in additional costs (excluding AFUDC) prior to completion in 2013. The Dresden Plant is located near Dresden, Ohio and is a natural gas, combined cycle power plant. When completed, the Dresden Plant will have a generating capacity of 580 MW.

2006

None

DISPOSITIONS

2009

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

In January 2009, TCC sold $60 million of transmission facilities to ETT. See the 2007 activity for ETT below.

2008

None

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 impact net income.

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

In November 2000, we made our initial investment in ICE. An initial public offering (IPO) occurred on November 15, 2005. 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 for the year ended December 31, 2007. Our remaining investment of approximately 138,000 shares as of December 31, 2008 and 2007 is recorded in Other Temporary Investments on our Consolidated Balance Sheets.

Texas REPs (Utility Operations segment)

As part of the purchase power and sale agreement related to the sale of our Texas REPs in 2002, we retained the right to share in earnings with Centrica from the two REPs above a threshold amount through 2006 if the Texas retail market developed increased earnings opportunities. In 2007, we received the final earnings sharing payment of $20 million. We received $70 million in 2006 for our share of earnings. The payments are reflected in Gain on Disposition of Assets, Net on our Consolidated Statement of Income.

Sweeny Cogeneration Plant (Generation and Marketing segment)

In October 2007, we sold our 50% equity interest in 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 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 2007, which is included in Other revenues on our 2007 Consolidated Statement of Income. In 2007, we recognized a total of $58 million in pretax gains on the Sweeny transactions ($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 in 2005. We completed the sale in February 2006 for approximately $29 million with no effect on our 2006 net income.

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 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 2006. Excluding the 2006 impairment of $209 million discussed above, the effect of the sale on our 2006 net income 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 $13 million and $10 million during 2008 and 2007, respectively. These margins were recorded in Gain on Disposition of Assets, Net on our 2008 and 2007 Consolidated Statements 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 (PPA). In 2003, we filed that TEM breached the PPA. In January 2008, we reached a settlement with TEM to resolve all litigation regarding the PPA. TEM paid us $255 million and we recorded the amount as a pretax gain under Asset Impairments and Other Related Charges on our Consolidated Statements of Income in 2008. See “TEM Litigation” section of Note 6.

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

See the above 2007 disclosure “Intercontinental Exchange, Inc. (ICE)” for information regarding sales in 2006.

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 2008, 2007 and 2006. Results of operations of these businesses are classified as shown in the following table:

	SEE-BOARD (a)	U.K. Generation (b)	Total
		(in millions)	
2008 Revenue	$ -	$ 2	$ 2
2008 Pretax Income	-	2	2
2008 Earnings, Net of Tax	-	12	12
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

(a) Relates to purchase price true-up adjustments and tax adjustments from the sale of SEEBOARD, a former U.K. utility subsidiary of AEP that was sold in 2002.

(b) The 2008 amounts relate primarily to favorable income tax reserve adjustments. The 2007 amounts relate to tax adjustments from the sale. The 2006 amounts relate to a release of accrued liabilities for the London office sublease and tax adjustments from the sale.

ASSET IMPAIRMENTS AND OTHER RELATED CHARGES

2008

We recorded $255 million as a pretax gain in January 2008 under Asset Impairments and Other Related Charges as a result of the settlement with TEM. See "Plaquemine Cogeneration Facility" section of this note for additional information.

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.

The categories of impairments and gains on dispositions include:

	Years Ended December 31,		
	2008	**2007**	**2006**
Asset Impairments and Other Related Charges (Pretax)		**(in millions)**	
Plaquemine Cogeneration Facility	$ -	$ -	$ 209
TEM Settlement	(255)	-	-
Total	$ (255)	$ -	$ 209
Gain (Loss) on Disposition of Assets, Net (Pretax)			
Texas REPs	$ -	$ 20	$ 70
Revenue Sharing on Plaquemine Cogeneration Facility	13	10	-
Gain on Sale of Land Rights and Other Miscellaneous Property, Plant and Equipment	3	11	(1)
Total	$ 16	$ 41	$ 69
Gain on Disposition of Equity Investments, Net (Pretax)			
Sweeny	$ -	$ 47	$ -
Other	-	-	3
Total	$ -	$ 47	$ 3

8. BENEFIT PLANS

We sponsor two qualified pension plans that we merged at December 31, 2008 and two unfunded 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 OPEB plans to provide medical and life insurance benefits for retired employees.

We adopted SFAS 158 in December 2006 and recognized the obligations associated with our defined benefit pension plans and OPEB plans in the balance sheets. We recognize an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. We record a SFAS 71 regulatory asset for qualifying SFAS 158 costs of our regulated operations that for ratemaking purposes are deferred for future recovery. The effect of SFAS 158 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 market conditions, 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, 2008, and their funded

status as of December 31 of each year:

Projected Plan Obligations, Plan Assets, Funded Status as of December 31, 2008 and 2007

	Pension Plans		Other Postretirement Benefit Plans	
	2008	**2007**	**2008**	**2007**
Change in Projected Benefit Obligation		(in millions)		
Projected Obligation at January 1	$ 4,109	$ 4,108	$ 1,773	$ 1,818
Service Cost	100	96	42	42
Interest Cost	249	235	113	104
Actuarial Loss (Gain)	139	(64)	2	(91)
Plan Amendments	-	18	-	-
Benefit Payments	(296)	(284)	(120)	(130)
Participant Contributions	-	-	24	22
Medicare Subsidy	-	-	9	8
Projected Obligation at December 31	$ 4,301	$ 4,109	$ 1,843	$ 1,773
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets at January 1	$ 4,504	$ 4,346	$ 1,400	$ 1,302
Actual Gain (Loss) on Plan Assets	(1,054)	435	(368)	115
Company Contributions	7	7	82	91
Participant Contributions	-	-	24	22
Benefit Payments	(296)	(284)	(120)	(130)
Fair Value of Plan Assets at December 31	$ 3,161	$ 4,504	$ 1,018	$ 1,400
Funded (Underfunded) Status at December 31	$ (1,140)	$ 395	$ (825)	$ (373)

We have significant investments in several trust funds to provide for future pension and OPEB payments. All of our trust funds' investments are diversified and managed in compliance with all laws and regulations. The value of the investments in these trusts declined substantially in 2008 due to decreases in domestic and international equity markets. Although the asset values are lower, this decline has not affected the funds' ability to make their required payments.

Amounts Recognized on the Balance Sheets as of December 31, 2008 and 2007

	Pension Plans		Other Postretirement Benefit Plans	
	2008	**2007**	**2008**	**2007**
		(in millions)		
Employee Benefits and Pension Assets – Prepaid Benefit Costs	$ -	$ 482	$ -	$ -
Other Current Liabilities – Accrued Short-term Benefit Liability	(9)	(8)	(4)	(4)
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(1,131)	(79)	(821)	(369)
Funded (Underfunded) Status	$ (1,140)	$ 395	$ (825)	$ (373)

SFAS 158 Amounts Recognized in Accumulated Other Comprehensive Income (AOCI) as of December 31, 2008, 2007 and 2006

	Pension Plans			Other Postretirement Benefit Plans		
	2008	2007	2006	2008	2007	2006
Components	(in millions)					
Net Actuarial Loss	$ 2,024	$ 534	$ 759	$ 715	$ 231	$ 354
Prior Service Cost (Credit)	13	14	(5)	3	4	4
Transition Obligation	-	-	-	70	97	124
Pretax AOCI	$ 2,037	$ 548	$ 754	$ 788	$ 332	$ 482
Recorded as						
Regulatory Assets	$ 1,660	$ 453	$ 582	$ 502	$ 204	$ 293
Deferred Income Taxes	132	33	60	100	45	66
Net of Tax AOCI	245	62	112	186	83	123
Pretax AOCI	$ 2,037	$ 548	$ 754	$ 788	$ 332	$ 482

Components of the Change in Plan Assets and Benefit Obligations Recognized in Pretax AOCI during the years ended December 31, 2008 and 2007 are as follows:

	Pensions Plans		Other Postretirement Benefit Plans	
	2008	2007	2008	2007
Components	(in millions)			
Actuarial Loss (Gain) During the Year	$ 1,527	$ (166)	$ 492	$ (111)
Amortization of Actuarial Loss	(37)	(59)	(9)	(12)
Prior Service Cost (Credit)	(1)	19	-	-
Amortization of Transition Obligation	-	-	(27)	(27)
Total Pretax AOCI Change for the Year	$ 1,489	$ (206)	$ 456	$ (150)

Pension and Other Postretirement Plans' Assets

The asset allocations for our pension plans at the end of 2008 and 2007, and the target allocation for 2009, by asset category, are as follows:

	Target Allocation	Percentage of Plan Assets at Year End	
	2009	2008	2007
Asset Category			
Equity Securities	55%	47%	57%
Real Estate	5%	6%	6%
Debt Securities	39%	42%	36%
Cash and Cash Equivalents	1%	5%	1%
Total	100%	100%	100%

The asset allocations for our OPEB plans at the end of 2008 and 2007, and target allocation for 2009, by asset category, are as follows:

	Target Allocation	Percentage of Plan Assets at Year End	
	2009	2008	2007
Asset Category			
Equity Securities	65%	53%	62%
Debt Securities	34%	43%	35%
Cash and Cash Equivalents	1%	4%	3%
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 the benefit trust funds from purchasing AEP securities (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies). However, our investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law, including ERISA.

The value of our pension plans' assets decreased substantially to $3.2 billion at December 31, 2008 from $4.5 billion at December 31, 2007. The qualified plans paid $289 million in benefits to plan participants during 2008 (nonqualified plans paid $7 million in benefits). The value of our OPEB plans' assets decreased substantially to $1 billion at December 31, 2008 from $1.4 billion at December 31, 2007. The OPEB plans paid $120 million in benefits to plan participants during 2008.

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,	
	2008	2007
Accumulated Benefit Obligation	(in millions)	
Qualified Pension Plans	$ 4,119	$ 3,914
Nonqualified Pension Plans	80	77
Total	$ 4,199	$ 3,991

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, 2008 and 2007 were as follows:

	Underfunded Pension Plans	
	December 31,	
	2008	2007
	(in millions)	
Projected Benefit Obligation	$ 4,301	$ 81
Accumulated Benefit Obligation	$ 4,199	$ 77
Fair Value of Plan Assets	3,161	-
Underfunded Accumulated Benefit Obligation	$ 1,038	$ 77

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 December 31, 2008	Pension Plans December 31, 2007	Other Postretirement Benefit Plans December 31, 2008	Other Postretirement Benefit Plans December 31, 2007
Discount Rate	6.00%	6.00%	6.10%	6.20%
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 2008, 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 2009 expected cash flows for the pension (qualified and nonqualified) and OPEB plans is as follows:

Employer Contribution	Pension Plans (in millions)	Other Postretirement Benefit Plans (in millions)
Required Contributions (a)	$ 9	$ 4
Additional Discretionary Contributions	-	158

(a) Contribution required to meet minimum funding requirement under ERISA plus direct payments for unfunded benefits.

The contribution to the pension plans is based on the minimum amount required by ERISA plus the amount to pay unfunded nonqualified benefits. The contribution to the OPEB plans is generally based on the amount of the OPEB 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 OPEB are as follows:

	Pension Plans	Other Postretirement Benefit Plans	
	Pension Payments	Benefit Payments	Medicare Subsidy Receipts
		(in millions)	
2009	$ 378	$ 116	$ (10)
2010	379	126	(11)
2011	377	136	(12)
2012	378	143	(13)
2013	384	151	(14)
Years 2014 to 2018, in Total	1,920	876	(87)

Components of Net Periodic Benefit Cost

The following table provides the components of our net periodic benefit cost for the plans for the years ended December 31, 2008, 2007 and 2006:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2008	2007	2006	2008	2007	2006
	(in millions)					
Service Cost	$ 100	$ 96	$ 97	$ 42	$ 42	$ 39
Interest Cost	249	235	231	113	104	102
Expected Return on Plan Assets	(336)	(340)	(335)	(111)	(104)	(94)
Amortization of Transition Obligation	-	-	-	27	27	27
Amortization of Prior Service Cost (Credit)	1	-	(1)	-	-	-
Amortization of Net Actuarial Loss	37	59	79	9	12	22
Net Periodic Benefit Cost	51	50	71	80	81	96
Capitalized Portion	(16)	(14)	(21)	(25)	(25)	(27)
Net Periodic Benefit Cost Recognized as Expense	$ 35	$ 36	$ 50	$ 55	$ 56	$ 69

Estimated amounts expected to be amortized to net periodic benefit costs for our plans during 2009 are shown in the following table:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Net Actuarial Loss	$ 56	$ 46
Prior Service Cost	1	1
Transition Obligation	-	27
Total Estimated 2009 Pretax AOCI Amortization	$ 57	$ 74
Expected to be Recorded as		
Regulatory Asset	$ 46	$ 48
Deferred Income Taxes	4	9
Net of Tax AOCI	7	17
Total	$ 57	$ 74

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**		
	2008	**2007**	**2006**	**2008**	**2007**	**2006**
Discount Rate	6.00%	5.75%	5.50%	6.20%	5.85%	5.65%
Expected Return on Plan Assets	8.00%	8.50%	8.50%	8.00%	8.00%	8.00%
Rate of Compensation Increase	5.90%	5.90%	5.90%	N/A	N/A	N/A

N/A = Not Applicable

The expected return on plan assets for 2008 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 OPEB plans measurement purposes are shown below:

Health Care Trend Rates	**2008**	**2007**
Initial	7.0%	7.5%
Ultimate	5.0%	5.0%
Year Ultimate Reached	2012	2012

Assumed health care cost trend rates have a significant effect on the amounts reported for the OPEB 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	$ 20	$ (16)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	196	(163)

American Electric Power System Retirement Savings Plan

We sponsor the American Electric Power System Retirement Savings Plan, a defined contribution retirement savings plan for substantially all employees who are not members of the United Mine Workers of America (UMWA). It is a qualified plan offering participants an opportunity to contribute a portion of their pay with features under Section 401(k) of the Internal Revenue Code. We provided matching contributions of 75% of the first 6% of eligible compensation contributed by an employee in 2008. Effective January 1, 2009, we match the first 1% of eligible employee contributions at 100% and the next 5% of contributions at 70%. The cost for company matching contributions totaled $71 million in 2008, $66 million in 2007 and $62 million in 2006.

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 2008, 2007 and 2006.

9. 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 dispose of SNF and to safely 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 most recent decommissioning cost study was performed in 2006. According to that study, the estimated cost of decommissioning and disposal of low-level radioactive waste ranges from $733 million to $1.3 billion in 2006 nondiscounted dollars. The wide range in estimated costs 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 $27 million in 2008, $32 million in 2007 and $30 million in 2006. Decommissioning costs recovered from customers are deposited in external trusts. The settlement agreement in I&M's base rate case will reduce the annual decommissioning cost recovery amount effective in 2009 to reflect the extension of the units' operating licenses granted by the NRC.

I&M deposited an additional $4 million in 2008, 2007 and 2006 in its decommissioning trust under funding provisions approved by regulatory commissions. At December 31, 2008 and 2007, the total decommissioning trust fund balance was $959 million and $1.1 billion, respectively. 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 net income, 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, 2008 and 2007, fees and related interest of $264 million and $259 million, respectively, for fuel consumed prior to April 7, 1983 have been recorded as Long-term Debt and funds collected from customers along with related earnings totaling $301 million and $285 million, respectively, to pay the fee are recorded as part of Spent Nuclear Fuel and Decommissioning Trusts. 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.

See "SFAS 157 Fair Value Measurements" section of Note 11 for disclosure of the fair value of assets within the trusts.

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

	December 31, 2008			2007		
	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in millions)					
Cash	$ 18	$ -	$ -	$ 22	$ -	$ -
Debt Securities	773	52	(3)	823	27	(6)
Equity Securities	469	89	(82)	502	205	(11)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,260	$ 141	$ (85)	$ 1,347	$ 232	$ (17)

Proceeds from sales of nuclear trust fund investments were $732 million, $696 million and $631 million in 2008, 2007 and 2006, respectively. Purchases of nuclear trust fund investments were $804 million, $777 million and $692 million in 2008, 2007 and 2006, respectively.

Gross realized gains from the sales of nuclear trust fund investments were $33 million, $15 million and $7 million in 2008, 2007 and 2006, respectively. Gross realized losses from the sales of nuclear trust fund investments were $7 million, $5 million and $7 million in 2008, 2007 and 2006, respectively.

The fair value of debt securities held in the nuclear trust funds, summarized by contractual maturities, at December 31, 2008 was as follows:

	Fair Value of Debt Securities
	(in millions)
Within 1 year	$ 51
1 year – 5 years	172
5 years – 10 years	209
After 10 years	341
Total	$ 773

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 a weekly indemnity payment resulting from an insured 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 $37 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 $12.5 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 $117.5 million on each licensed reactor in the U.S. payable in annual installments of $17.5 million. As a result, I&M could be assessed $235 million per nuclear incident payable in annual installments of $35 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 $12.2 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, net income, cash flows and financial condition could be adversely affected.

10. BUSINESS SEGMENTS

Our primary business is 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. While our Utility Operations segment remains our primary business segment, other segments include our AEP River Operations segment with significant barging activities and our Generation and Marketing segment, which includes our nonregulated generating, marketing and risk management activities primarily 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.

AEP River Operations

- Commercial barging operations that annually transport approximately 33 million tons of coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers. Approximately 38% of the barging is for transportation of agricultural products, 30% for coal, 13% for steel and 19% for other commodities. Effective July 30, 2008, AEP MEMCO LLC's name was changed to AEP River Operations LLC.

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 7.

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

- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense, and other nonallocated costs.
- Tax and interest expense adjustments related to our UK operations which were sold in 2004 and 2002.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts are financial derivatives which will gradually settle and completely expire in 2011.
- Other energy supply related businesses, including the Plaquemine Cogeneration Facility, which was sold in 2006. See "Plaquemine Cogeneration Facility" section of Note 7.
- The 2008 cash settlement of a purchase power and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in 2006. The cash settlement of $255 million ($164 million, net of tax) is included in Net Income.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

The tables below present our reportable segment information for the years ended December 31, 2008, 2007 and 2006 and balance sheet information as of December 31, 2008 and 2007. These amounts include certain estimates and allocations where necessary. We reclassified prior year amounts to conform to the current year's segment presentation. See "FSP FIN 39-1 "Amendment of FASB Interpretation No. 39" (FSP FIN 39-1)" section of Note 2 for discussion of changes in netting certain balance sheet amounts.

		Nonutility Operations				
	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)		
Year Ended December 31, 2008						
Revenues from:						
External Customers	$ 13,326 (e)	$ 616	$ 485	$ 13	$ -	$ 14,440
Other Operating Segments	240 (e)	30	(122)	9	(157)	-
Total Revenues	$ 13,566	$ 646	$ 363	$ 22	$ (157)	$ 14,440
Depreciation and Amortization	$ 1,450	$ 14	$ 28	$ 2	$ (11)(b)	$ 1,483
Interest Income	42	-	1	78	(65)	56
Interest Expense	916	5	22	94	(79)(b)	958
Income Tax Expense	515	26	17	84	-	642
Income Before Discontinued Operations and Extraordinary Loss	$ 1,115	$ 55	$ 65	$ 133	$ -	$ 1,368
Discontinued Operations, Net of Tax	-	-	-	12	-	12
Net Income	$ 1,115	$ 55	$ 65	$ 145	$ -	$ 1,380
Gross Property Additions	$ 3,871	$ 116	$ 2	$ (29)(c)	$ -	$ 3,960

		Nonutility Operations				
	Utility Operations	AEP River 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	$ 12,655	$ 537	$ 302	$ 35	$ (149)	$ 13,380
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 and Extraordinary Loss	$ 1,031	$ 61	$ 67	$ (15)	$ -	$ 1,144
Discontinued Operations, Net of Tax	-	-	-	24	-	24
Extraordinary Loss, Net of Tax	(79)	-	-	-	-	(79)
Net Income	$ 952	$ 61	$ 67	$ 9	$ -	$ 1,089
Gross Property Additions	$ 4,050	$ 12	$ 2	$ 4 (c)	$ -	$ 4,068

Year Ended December 31, 2006	Utility Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
	(in millions)					
Revenues from:						
External Customers	$ 12,066	$ 520	$ 62	$ (26)	$ -	$ 12,622
Other Operating Segments	(55)	12	-	97	(54)	-
Total Revenues	$ 12,011	$ 532	$ 62	$ 71	$ (54)	$ 12,622
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 and Extraordinary Loss	$ 1,028	$ 80	$ 12	$ (128)	$ -	$ 992
Discontinued Operations, Net of Tax	-	-	-	10	-	10
Net Income (Loss)	$ 1,028	$ 80	$ 12	$ (118)	$ -	$ 1,002
Gross Property Additions	$ 3,494	$ 7	$ 1	$ 26 (c)	$ -	$ 3,528

December 31, 2008	Utility Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments (b)	Consolidated
	(in millions)					
Total Property, Plant and Equipment	$ 48,997	$ 371	$ 565	$ 10	$ (233)	$ 49,710
Accumulated Depreciation and Amortization	16,525	73	140	8	(23)	16,723
Total Property, Plant and Equipment – Net	$ 32,472	$ 298	$ 425	$ 2	$ (210)	$ 32,987
Total Assets	$ 43,773	$ 439	$ 737	$ 14,501	$ (14,295)(d)	$ 45,155
Investments in Equity Method Subsidiaries	22	2	-	-	-	24

		Nonutility Operations				
	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments (b)	Consolidated
				(in millions)		
December 31, 2007						
Total Property, Plant and Equipment	$ 45,514	$ 263	$ 567	$ 38	$ (237)	$ 46,145
Accumulated Depreciation and Amortization	16,107	61	112	7	(12)	16,275
Total Property, Plant and Equipment – Net	$ 29,407	$ 202	$ 455	$ 31	$ (225)	$ 29,870
Total Assets	$ 39,298	$ 340	$ 697	$ 12,117	$ (12,133)(d)	$ 40,319
Investments in Equity Method Subsidiaries	14	2	-	-	-	16

(a) All Other includes:
- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense, and other nonallocated costs.
- Tax and interest expense adjustments related to our UK operations which were sold in 2004 and 2002.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts are financial derivatives which will gradually settle and completely expire in 2011.
- Other energy supply related businesses, including the Plaquemine Cogeneration Facility, which was sold in 2006. See "Plaquemine Cogeneration Facility" section of Note 7.
- The 2008 cash settlement of a purchase power and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in 2006. The cash settlement of $255 million ($164 million, net of tax) is included in Net Income.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

(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 $8 million, $4 million and $25 million in 2008, 2007 and 2006, respectively, related to the acquisition of turbines by one of our nonregulated, wholly-owned subsidiaries. These turbines were refurbished and transferred to a generating facility within our Utility Operations segment in the fourth quarter of 2008. The transfer of these turbines resulted in the elimination of $37 million from All Other and the addition of $37 million to Utility Operations.

(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 AEP Energy Partners, Inc. (AEPEP) (Generation and Marketing segment) and entered into intercompany financial and physical purchase and sales agreements with AEPEP. As a result, we reported third-party net purchases or sales activity for these energy marketing contracts as Revenues from External Customers for the Utility Operations segment. This is offset by the Utility Operations segment's related net sales (purchases) for these contracts to AEPEP in Revenues from Other Operating Segments of $122 million and $406 million for the years ended December 31, 2008 and 2007, respectively. The Generation and Marketing segment also reports these purchases or sales contracts with Utility Operations as Revenues from Other Operating Segments.

11. DERIVATIVES, HEDGING AND FAIR VALUE MEASUREMENTS

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 will fail to perform to the contract 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. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value 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 net income 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 longer 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 Net Income 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 Net Income. We recognize any hedge ineffectiveness in Net Income 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. However, unrealized gains and losses in regulated jurisdictions for both trading and non-trading derivative instruments are recorded as a regulatory asset (for losses) or a regulatory liability (for gains).

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 2008, 2007 and 2006, 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 or energy purchases. Realized gains and losses on these derivatives designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale 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 2008, 2007 and 2006, we recognized immaterial amounts in Net Income 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 2008, 2007 and 2006, we recognized immaterial amounts in Net Income 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 expense on our Consolidated Statements of Income over 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 2008, 2007 and 2006, we recognized no hedge ineffectiveness related to these derivative transactions.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheet at December 31, 2008 were:

	Hedging Assets (a)	Hedging Liabilities (a)	Accumulated Other Comprehensive Income (Loss) After Tax	Portion Expected to be Reclassified to Net Income During the Next Twelve Months
		(in millions)		
Power	$ 34	$ (23)	$ 7	$ 7
Interest Rate	-	(8)	(29)	(5)
Total	$ 34	$ (31)	$ (22)	$ 2

(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, 2007 were:

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

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

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, 2008, 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 47 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, 2008:

	Amount
	(in millions)
Balance at December 31, 2005	$ (27)
Changes in Fair Value	13
Reclasses from AOCI to Net Income	8
Balance at December 31, 2006	(6)
Changes in Fair Value	(5)
Reclasses from AOCI to Net Income	(15)
Balance at December 31, 2007	(26)
Changes in Fair Value	(3)
Reclasses from AOCI to Net Income	7
Balance at December 31, 2008	$ (22)

Credit Risk

Credit risk is our risk of financial loss if counterparties fail to perform their contractual obligations. We limit our credit risk by maintaining stringent credit policies whereby we assess a counterparty's creditworthiness prior to transacting with them and continue to assess their creditworthiness on an ongoing basis. We employ the use of standardized master agreements which may include collateral requirements. These master agreements facilitate the netting of cash flows associated with a single counterparty. Cash, letters of credit, and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure is exceeded in excess of an established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with our credit policy. In addition, collateral agreements also provide that the failure or inability to post collateral is sufficient cause for termination and liquidation of all positions.

FAIR VALUE MEASUREMENTS

SFAS 107 Fair Value Measurements

The fair values of Long-term Debt are based on quoted market prices for the same or similar issues and the current 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 Long-term Debt at December 31, 2008 and 2007 are summarized in the following tables:

	December 31,			
	2008		2007	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
Long-term Debt	$ 15,983	$ 15,113	$ 14,994	$ 14,917

SFAS 157 Fair Value Measurements

As described in Note 2, we completed our adoption of SFAS 157 effective January 1, 2009. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures. The adoption of SFAS 157 had an immaterial impact on our financial statements. 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 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), 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.

In accordance with SFAS 157, assets and liabilities are classified based on the inputs utilized in the fair value measurement. SFAS 157 provides definitions for two types of inputs: observable and unobservable. Observable inputs are valuation inputs that reflect the assumptions market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the reporting entity. Unobservable inputs are valuation inputs that reflect the reporting entity's own assumptions about the assumptions market participants would use in pricing the asset or liability developed based on the best information in the circumstances.

As defined in SFAS 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurement).

Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 1 inputs primarily consist of exchange traded contracts, listed equities and U.S. government treasury securities that exhibit sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 inputs are inputs other than quoted prices included within level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, exchange traded contracts where there was not sufficient market activity to warrant inclusion in level 1, OTC broker quotes that are corroborated by the same or similar transactions that have occurred in the market and certain non-exchange-traded debt securities.

Level 3 inputs are unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that the observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Level 3 inputs primarily consist of unobservable market data or are valued based on models and/or assumptions.

Risk Management Contracts include exchange traded, OTC and bilaterally executed derivative contracts. Exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified within level 1. Other actively traded derivative fair values are verified using broker or dealer quotations, similar observable market transactions in either the listed or OTC markets or valued using pricing models where significant valuation inputs are directly or indirectly observable in active markets. Derivative instruments, primarily swaps, forwards, and options that meet these characteristics are classified within level 2. Bilaterally executed agreements are derivative contracts entered into directly with third parties, and at times these instruments may be complex structured transactions that are tailored to meet the specific customer’s energy requirements. Structured transactions utilize pricing models that are widely accepted in the energy industry to measure fair value. We use a consistent modeling approach to value similar instruments. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in level 2. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. In addition, long-dated and illiquid complex or structured transactions or FTRs can introduce the need for internally developed modeling inputs based upon extrapolations and assumptions of observable market data to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized in level 3. In certain instances, the fair values of the transactions included in level 3 that use internally developed model inputs are offset partially or in full, by transactions included in level 2 where observable market data exists for the offsetting transaction.

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2008. As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of December 31, 2008

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents					
Cash and Cash Equivalents (a)	$ 304	$ -	$ -	$ 60	$ 364
Debt Securities (b)	-	47	-	-	47
Total Cash and Cash Equivalents	304	47	-	60	411
Other Temporary Investments					
Cash and Cash Equivalents (c)	217	-	-	26	243
Debt Securities (d)	56	-	-	-	56
Equity Securities (e)	28	-	-	-	28
Total Other Temporary Investments	301	-	-	26	327
Risk Management Assets					
Risk Management Contracts (f)	61	2,413	86	(2,022)	538
Cash Flow and Fair Value Hedges (f)	6	32	-	(4)	34
Dedesignated Risk Management Contracts (g)	-	-	-	39	39
Total Risk Management Assets	67	2,445	86	(1,987)	611
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (h)	-	6	-	12	18
Debt Securities (i)	-	773	-	-	773
Equity Securities (e)	469	-	-	-	469
Total Spent Nuclear Fuel and Decommissioning Trusts	469	779	-	12	1,260
Total Assets	$ 1,141	$ 3,271	$ 86	$ (1,889)	$ 2,609
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (f)	$ 77	$ 2,213	$ 37	$ (2,054)	$ 273
Cash Flow and Fair Value Hedges (f)	1	34	-	(4)	31
Total Risk Management Liabilities	$ 78	$ 2,247	$ 37	$ (2,058)	$ 304

(a) Amounts in "Other" column primarily represent cash deposits in bank accounts with financial institutions. Level 1 amounts primarily represent investments in money market funds.

(b) Amount represents commercial paper investments with maturities of less than ninety days.

(c) Amounts in "Other" column primarily represent cash deposits with third parties. Level 1 amounts primarily represent investments in money market funds.

(d) Amounts represent debt-based mutual funds.

(e) Amount represents publicly traded equity securities and equity-based mutual funds.

(f) Amounts in "Other" column primarily represent counterparty netting of risk management contracts and associated cash collateral under FSP FIN 39-1.

(g) "Dedesignated Risk Management Contracts" are contracts that were originally MTM but were subsequently elected as normal under SFAS 133. At the time of the normal election, the MTM value was frozen and no longer fair valued. This will be amortized into Utility Operations Revenues over the remaining life of the contract.

(h) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 2 amounts primarily represent investments in money market funds.

(i) Amounts represent corporate, municipal and treasury bonds.

The following table sets forth a reconciliation of changes in the fair value of net trading derivatives and other investments classified as level 3 in the fair value hierarchy:

Year Ended December 31, 2008	Net Risk Management Assets (Liabilities)	Other Temporary Investments	Investments in Debt Securities
		(in millions)	
Balance as of January 1, 2008	$ 49	$ -	$ -
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets)	-	-	-
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	12	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-
Purchases, Issuances and Settlements (b)	-	(118)	(17)
Transfers in and/or out of Level 3 (c)	(36)	118	17
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	24	-	-
Balance as of December 31, 2008	$ 49	$ -	$ -

(a) Included in revenues on our Consolidated Statements of Income.
(b) Includes principal amount of securities settled during the period.
(c) "Transfers in and/or out of Level 3" represent existing assets or liabilities that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as level 3 for which the lowest significant input became observable during the period.
(d) "Changes 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.

12. INCOME TAXES

The details of our consolidated income taxes before discontinued operations and extraordinary loss as reported are as follows:

	Years Ended December 31, 2008	2007	2006
		(in millions)	
Federal:			
Current	$ 164	$ 464	$ 429
Deferred	456	35	5
Total	620	499	434
State and Local:			
Current	(1)	1	61
Deferred	22	16	(10)
Total	21	17	51
International:			
Current	1	-	-
Deferred	-	-	-
Total	1	-	-
Total Income Tax Expense Before Discontinued Operations and Extraordinary Loss	$ 642	$ 516	$ 485

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, 2008	2007	2006
		(in millions)	
Net Income	$ 1,380	$ 1,089	$ 1,002
Discontinued Operations (Net of Income Tax of $(10) Million, $(18) Million and $(1) Million in 2008, 2007 and 2006, respectively)	(12)	(24)	(10)
Extraordinary Loss, (Net of Income Tax of $39 Million in 2007)	-	79	-
Preferred Stock Dividends	3	3	3
Income Before Preferred Stock Dividends of Subsidiaries	1,371	1,147	995
Income Tax Expense Before Discontinued Operations and Extraordinary Loss	642	516	485
Pretax Income	$ 2,013	$ 1,663	$ 1,480
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 705	$ 582	$ 518
Increase (Decrease) in Income Taxes resulting from the following items:			
Depreciation	23	29	38
Investment Tax Credits, Net	(19)	(24)	(29)
Energy Production Credits	(20)	(18)	(19)
State Income Taxes	13	11	33
Removal Costs	(21)	(21)	(15)
AFUDC	(24)	(18)	(18)
Medicare Subsidy	(12)	(12)	(12)
Tax Reserve Adjustments	2	(8)	9
Other	(5)	(5)	(20)
Total Income Tax Expense Before Discontinued Operations and Extraordinary Loss	$ 642	$ 516	$ 485
Effective Income Tax Rate	31.9%	31.0%	32.8%

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

	December 31, 2008	2007
	(in millions)	
Deferred Tax Assets	$ 2,632	$ 2,284
Deferred Tax Liabilities	(7,750)	(7,023)
Net Deferred Tax Liabilities	$ (5,118)	$ (4,739)
Property-Related Temporary Differences	$ (3,718)	$ (3,300)
Amounts Due from Customers for Future Federal Income Taxes	(218)	(202)
Deferred State Income Taxes	(362)	(324)
Securitized Transition Assets	(776)	(806)
Regulatory Assets	(871)	(225)
Accrued Pensions	284	(211)
Deferred Income Taxes on Other Comprehensive Loss	240	83
Accrued Nuclear Decommissioning	(277)	(286)
Deferred Fuel	(76)	(19)
All Other, Net	656	551
Net Deferred Tax Liabilities	$ (5,118)	$ (4,739)

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. We have completed the exam for the years 2001 through 2003 and have issues that we are pursuing 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 net income.

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 net income. 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 on January 1, 2007, we began recognizing interest accruals related to uncertain tax positions in interest income or expense as applicable, and penalties in Other Operation and Maintenance. The impact of this interpretation was an unfavorable adjustment to the 2007 opening balance of retained earnings of $17 million. We reported $10 million and $2 million of interest expense, $21 million and $5 million of interest income and reversed $13 million and $17 million of prior period interest expense in 2008 and 2007, respectively. We had approximately $33 million for the receipt of interest accrued at December 31, 2008 and approximately $26 million and $16 million for the payment of interest and penalties accrued at December 31, 2008 and 2007, respectively.

The reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2008	2007
	(in millions)	
Balance at January 1,	$ 222	$ 175
Increase - Tax Positions Taken During a Prior Period	41	75
Decrease - Tax Positions Taken During a Prior Period	(45)	(43)
Increase - Tax Positions Taken During the Current Year	27	20
Decrease - Tax Positions Taken During the Current Year	(5)	-
Increase - Settlements with Taxing Authorities	3	2
Decrease - Lapse of the Applicable Statute of Limitations	(6)	(7)
Balance at December 31,	$ 237	$ 222

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 allocated credits during this round of credit awards. After one of the original credit recipients surrendered its credits in the Fall of 2007, the IRS announced a supplemental credit round for the Spring of 2008. We filed a new application in 2008 for the West Virginia IGCC project and in July 2008 the IRS allocated the project $134 million in credits. In September 2008, we entered into a memorandum of understanding with the IRS concerning the requirements of claiming the credits.

Several tax bills and other legislation with tax-related sections were enacted in 2006 and 2007, including the Pension Protection Act of 2006, Tax Relief and Health Care Act of 2006, 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 2006 and 2007 did not materially affect our net income, cash flows or financial condition.

The Economic Stimulus Act of 2008 was signed into law by the President in February 2008. It provided enhanced expensing provisions for certain assets placed in service in 2008 and a 50% bonus depreciation provision similar to the one in effect in 2003 through 2004 for assets placed in service in 2008. The enacted provisions did not have a material impact on net income or financial condition, but provided a material favorable cash flow benefit of approximately $200 million.

In October 2008, the Emergency Economic Stabilization Act of 2008 (the 2008 Act) was signed into law. The 2008 Act extended several expiring tax provisions and added new energy incentive provisions. The legislation impacted the availability of research credits, accelerated depreciation of smart meters, production tax credits and energy efficient commercial building deductions. We have evaluated the impact of the law change and the application of the law change will not materially impact our net income, cash flows or financial condition.

In February 2009, the American Recovery and Reinvestment Tax Act of 2009 (the 2009 Act) was signed into law. The 2009 Act extended the bonus depreciation deduction for one year and provides for a long-term extension of the renewable production tax credit for wind energy and other properties. The 2009 Act also establishes a new investment tax credit for the manufacture of advanced energy property as well as appropriations for advanced energy research projects, carbon capture and storage and gridSMART technology. We have evaluated the impact of the law change and the application of the law change will not materially impact our net income or financial condition, but is expected to have a positive material impact on cash flows.

State Tax Legislation

In June 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. At December 31, 2008, the $57 million regulatory liability was fully amortized.

The Ohio legislation also imposed 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 $9 million, $6 million and $4 million were recorded in 2008, 2007 and 2006, 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 law reduced Texas income tax rates and was 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.

In July 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.

In September 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 net income, cash flows or financial condition.

In March 2008, the Governor of West Virginia signed legislation providing for, among other things, a reduction in the West Virginia corporate income tax rate from 8.75% to 8.5% beginning in 2009. The corporate income tax rate could also be reduced to 7.75% in 2012 and 7% in 2013 contingent upon the state government achieving certain minimum levels of shortfall reserve funds. We have evaluated the impact of the law change and the application of the law change will not materially impact our net income, cash flows or financial condition.

13. 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,		
	2008	2007	2006
Lease Rental Costs		(in millions)	
Net Lease Expense on Operating Leases	$ 368	$ 364	$ 340
Amortization of Capital Leases	97	68	64
Interest on Capital Leases	16	20	17
Total Lease Rental Costs	$ 481	$ 452	$ 421

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,	
	2008	2007
	(in millions)	
Property, Plant and Equipment Under Capital Leases		
Production	$ 70	$ 89
Distribution	15	15
Other	443	458
Construction Work in Progress	-	39
Total Property, Plant and Equipment Under Capital Leases	528	601
Accumulated Amortization	205	232
Net Property, Plant and Equipment Under Capital Leases	$ 323	$ 369
Obligations Under Capital Leases		
Noncurrent Liability	$ 226	$ 267
Liability Due Within One Year	99	104
Total Obligations Under Capital Leases	$ 325	$ 371

Future minimum lease payments consisted of the following at December 31, 2008:

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in millions)	
2009	$ 94	$ 336
2010	67	310
2011	52	461
2012	26	222
2013	20	215
Later Years	149	1,671
Total Future Minimum Lease Payments	$ 408	$ 3,215
Less Estimated Interest Element	83	
Estimated Present Value of Future Minimum Lease Payments	$ 325	

Master Lease Agreements

We lease certain equipment under master lease agreements. GE Capital Commercial Inc. (GE) notified us in November 2008 that they elected to terminate our Master Leasing Agreements in accordance with the termination rights specified within the contract. In 2010 and 2011, we will be required to purchase all equipment under the lease and pay GE an amount equal to the unamortized value of all equipment then leased. As a result, the unamortized value of this equipment is reflected in our future minimum lease payments for 2010 ($298 thousand) and 2011 ($195 million). In December 2008, we signed new master lease agreements with one-year commitment periods that include lease terms of up to 10 years. We expect to enter into additional replacement leasing arrangements for the equipment affected by this notification prior to the termination dates of 2010 and 2011.

For equipment under the GE master lease agreements that expire prior to 2011, 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. Under the new master lease agreements, the lessor is guaranteed receipt of up to 68% of the unamortized balance at the end of the lease term. If the actual 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 actual fair market value and unamortized balance, with the total guarantee not to exceed 68% of the unamortized balance. At December 31, 2008, the maximum potential loss for these lease agreements was approximately $20 million assuming the fair market value of the equipment is zero at the end of the lease term. Historically, at the end of the lease term the fair market value has been in excess of the unamortized balance.

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, 2008 are as follows:

Future Minimum Lease Payments	**AEGCo**	**I&M**
	(in millions)	
2009	$ 74	$ 74
2010	74	74
2011	74	74
2012	74	74
2013	74	74
Later Years	665	665
Total Future Minimum Lease Payments	$ 1,035	$ 1,035

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 is accounted for as an operating lease. 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 initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years, via the renewal options. The future minimum lease obligations are $20 million for I&M and $23 million for SWEPCo for the remaining railcars as of December 31, 2008. These obligations are included in the future minimum lease payments schedule earlier in this note.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which declines from approximately 84% under the current five year lease term to 77% at the end of the 20-year term of the projected fair market value of the equipment. I&M and SWEPCo have assumed the guarantee under the return-and-sale option. I&M's maximum potential loss related to the guarantee is approximately $12 million ($8 million, net of tax) and SWEPCo's is approximately $13 million ($9 million, net of tax) assuming the fair market value of the equipment is zero at the end of the current five-year 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.

Sabine Dragline Lease

In December 2006, Sabine Mining Company (Sabine), an entity consolidated under FIN 46R, entered into a capital lease agreement with a nonaffiliated company to finance the purchase of a $53 million electric dragline for Sabine's mining operations. In 2006, the initial capital outlay for the dragline was $26 million. Sabine incurred an additional $14 million and $13 million of transportation, assembly and upgrade costs in 2008 and 2007 respectively. The dragline was completed in August 2008. For the years ended December 31, 2008 and 2007, Sabine paid $1 million and $2 million, respectively, of interim rent prior to the completion in August 2008. Sabine began quarterly principal and interest payments on the outstanding lease obligation in November 2008. The capital lease asset was included in Property, Plant and Equipment – Other and Construction Work in Progress on our December 31, 2008 and 2007 Consolidated Balance Sheets, respectively. The short-term and long-term capital lease obligations are included in Current Liabilities – Other and Noncurrent Liabilities – Deferred Credits and Other on our December 31, 2008 and 2007 Consolidated Balance Sheets. The 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. In December 2007, 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 $57 million are included in our future minimum lease payments schedule earlier in this note. The net capital lease asset is included in Property, Plant and Equipment – Other and the short-term and long-term capital lease obligations are included in Current Liabilities – Other and Noncurrent Liabilities – Deferred Credits and Other, respectively, on our December 31, 2008 and 2007 Consolidated Balance Sheets. The future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2008 are as follows, based on estimated fuel burn:

Future Minimum Lease Payments	**(in millions)**
2009	$ 25
2010	18
2011	4
2012	7
2013	3
Later Years	-
Total Future Minimum Lease Payments	$ 57

14. FINANCING ACTIVITIES

Common Stock

We issued 68 thousand, 2.4 million and 2.3 million shares of common stock in connection with our stock option plan during 2008, 2007 and 2006, respectively.

Set forth below is a reconciliation of common stock share activity for the years ended December 31, 2008, 2007 and 2006:

Shares of Common Stock	**Issued**	**Held in Treasury**
Balance, January 1, 2006	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
Issued	4,394,552	-
Treasury Stock Contributed to AEP Foundation	-	(1,250,000)
Balance, December 31, 2008	426,321,248	20,249,992

Preferred Stock

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

	December 31, 2008			
	Call Price Per Share (a)	**Shares Authorized (b)**	**Shares Outstanding (c)**	**Amount (in millions)**
Not Subject to Mandatory Redemption:				
4.00% - 5.00%	$102-$110	1,525,903	606,878	$ 61

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

(a) 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.

(b) As of December 31, 2008 and 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.

(c) There were no shares of preferred stock redeemed in 2008. The number of shares of preferred stock redeemed was 166 shares in 2007 and 598 shares in 2006.

Long-term Debt

Type of Debt and Maturity	Weighted Average Interest Rate December 31, 2008	Interest Rate Ranges at December 31, 2008	2007	Outstanding at December 31, 2008	2007
				(in millions)	
Senior Unsecured Notes (a)					
2008-2011	5.07%	4.3875%-6.60%	3.60%-6.60%	$ 2,065	$ 2,494
2012-2018	5.58%	4.85%-6.375%	4.85%-6.375%	4,548	3,918
2019-2038	6.38%	5.625%-7.00%	5.625%-6.70%	4,456	3,493
Pollution Control Bonds (b)					
2008-2011 (c)	5.69%	4.15%-7.125%	4.15%-4.50%	336	131
2012-2024 (c)	4.03%	0.75%-6.05%	3.70%-6.05%	775	811
2025-2042	5.67%	0.85%-13.00%	3.80%-6.00%	835	1,248
Notes Payable (d)					
2008-2024	6.66%	4.47%-7.49%	4.47%-9.60%	233	311
Securitization Bonds (e)					
2008-2020	5.34%	4.98%-6.25%	4.98%-6.25%	2,132	2,257
Junior Subordinated Debentures (f)					
2063	8.75%	8.75%	-	315	-
First Mortgage Bonds (g)					
2008	-	-	7.125%	-	19
Notes Payable to Trust					
2043	-	-	5.25%	-	113
Spent Nuclear Fuel Obligation (h)				264	259
Other Long-term Debt (i)					
2011-2026	3.50%	3.20125%-13.718%	13.718%	88	2
Unamortized Discount (net)				(64)	(62)
Total Long-term Debt Outstanding				15,983	14,994
Less Portion Due Within One Year				447	792
Long-term Portion				$ 15,536	$ 14,202

(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 may 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) Certain pollution control bonds are subject to mandatory redemption earlier than the maturity date. Consequently, these bonds have been classified for maturity and repayment purposes based on the mandatory redemption date.
(d) 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.
(e) 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.
(f) The net proceeds from the sale of junior subordinated debentures were used for general corporate purposes including the payment of short-term indebtedness.
(g) 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. The defeased TCC first mortgage bonds were retired in February 2008. Trust fund assets related to this obligation of $22 million are included in Other Temporary Investments on our Consolidated Balance Sheets at December 31, 2007.
(h) Spent nuclear fuel obligation consists of a liability along with accrued interest for disposal of spent nuclear fuel (see Note 9).
(i) Other long-term debt in 2007 and 2008 consists of a financing obligation under a sale and leaseback agreement. In 2008, AEGCo issued an $85 million 3-year credit facility to be used for working capital and other general corporate purposes.

LONG-TERM DEBT OUTSTANDING AT DECEMBER 31, 2008 IS PAYABLE AS FOLLOWS:

	2009	2010	2011	2012	2013	After 2013	Total
				(in millions)			
Principal Amount	$ 447	$ 1,851	$ 809	$ 601	$ 1,297	$ 11,042	$ 16,047
Unamortized Discount							(64)
Total Long-term Debt Outstanding at December 31, 2008							$ 15,983

In January 2009, I&M issued $475 million of 7.00% Senior Unsecured Notes due in 2019.

In January 2009, TCC retired $50 million of 4.98% and $31 million of 5.56% Securitization Bonds due in 2010.

In February 2009, PSO reissued $34 million of 5.25% Pollution Control Bonds due in 2014.

In the first quarter of 2008, bond insurers' exposure in connection with developments in the subprime credit market resulted in increasing occurrences of failed auctions for tax-exempt long-term debt sold at auction rates. Consequently, we chose to exit the auction-rate debt market and reduced our outstanding auction-rate securities from the December 2007 balance by $1.2 billion. As of December 31, 2008, $272 million of our auction-rate tax-exempt long-term debt, with rates ranging between 2.034% and 13%, remained outstanding with rates reset every 35 days. 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. As of December 31, 2008, $367 million of the prior auction-rate debt was issued in a weekly variable rate mode supported by letters of credit at variable rates ranging from 0.85% to 1.52%, $495 million was issued at fixed rates ranging from 4.5% to 5.625% and trustees held, on our behalf, approximately $330 million of our reacquired auction-rate tax-exempt long-term debt which we plan to reissue to the public as market conditions permit.

As of December 31, 2008, approximately $218 million of the $272 million of outstanding auction-rate debt relates to a lease structure with JMG that we are unable to refinance without their consent. The rates for this debt range from 6.388% to 13%. The initial term for the JMG lease structure matures on March 31, 2010. We are evaluating whether to terminate this facility prior to maturity. Termination of this facility requires approval from the PUCO.

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 had a wholly-owned business trust that issued trust preferred securities. Effective July 1, 2003, the trust was deconsolidated due to the implementation of FIN 46R. The SWEPCo trust, which held 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, 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, are reported as Notes Payable to Trust within Long-term Debt. Both the investment in the trust and the Junior Subordinated Debentures were retired in 2008.

Lines of Credit and Short-term Debt

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, 2008, we had credit facilities totaling $3 billion to support our commercial paper program (see "Credit Facilities" section below). For the corporate borrowing program, the maximum amount of commercial paper outstanding during 2008 was $1.2 billion and the weighted average interest rate of commercial paper outstanding during the year was 3.32%. No commercial paper was outstanding at December 31, 2008 due to market conditions. In 2008, we borrowed $2 billion under these credit facilities. Our outstanding short-term debt was as follows:

	December 31,			
	2008		2007	
Type of Debt	Outstanding Amount (in thousands)	Interest Rate (a)	Outstanding Amount (in thousands)	Interest Rate (a)
Commercial Paper – AEP	$ -	-	$ 659,135	5.54%
Commercial Paper – JMG (b)	-	-	701	5.35%
Line of Credit – Sabine Mining Company (c)	7,172	1.54%	285	5.25%
Lines of Credit – AEP	1,969,000	2.28% (d)	-	-
Total	$ 1,976,172		$ 660,121	

(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 Mining Company is consolidated under FIN 46R. This line of credit does not reduce available liquidity under AEP's credit facilities.
(d) Rate based on LIBOR.

Credit Facilities

As of December 31, 2008, in support of our commercial paper program, we had two $1.5 billion credit facilities which were reduced by Lehman Brothers Holdings Inc.'s commitment amount of $46 million following its bankruptcy. In March 2008, the credit facilities were amended so that $750 million may be issued under each credit facility as letters of credit.

In April 2008, we entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement which were reduced by Lehman Brothers Holdings Inc.'s commitment amount of $23 million and $12 million, respectively, following its bankruptcy. Under the facilities, we may issue letters of credit. As of December 31, 2008, $372 million of letters of credit were issued by subsidiaries under the 3-year credit agreement to support variable rate Pollution Control Bonds.

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 our Consolidated Balance Sheets and allowing AEP Credit to repay any debt obligations to the affiliated utility subsidiaries. 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 2008, we renewed AEP Credit's sale of receivables agreement. The sale of receivables agreement provides a commitment of $700 million from banks and commercial paper conduits to purchase receivables from AEP Credit. This agreement will expire in October 2009. We intend to extend or replace the sale of receivables agreement. The previous sale of receivables agreement, which expired in October 2008 and was extended until October 2009, provided a commitment of $650 million from banks and commercial paper conduits to purchase receivables from AEP Credit. Under the previous sale of receivable agreement, the commitment increased to $700 million for the months of August and September to accommodate seasonal demand. At December 31, 2008, $650 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, SWEPCo 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,		
	2008	**2007**	**2006**
		($ in millions)	
Proceeds from Sale of Accounts Receivable	$ 7,717	$ 6,970	$ 6,849
Loss on Sale of Accounts Receivable	20	33	31
Average Variable Discount Rate	3.19%	5.39%	5.02%

	December 31,	
	2008	**2007**
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 118	$ 71
Deferred Revenue from Servicing Accounts Receivable	1	1
Retained Interest if 10% Adverse Change in Uncollectible Accounts	116	68
Retained Interest if 20% Adverse Change in Uncollectible Accounts	114	66

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

	December 31,	
	2008	**2007**
	(in millions)	
Customer Accounts Receivable Retained	$ 569	$ 730
Accrued Unbilled Revenues Retained	449	379
Miscellaneous Accounts Receivable Retained	90	60
Allowance for Uncollectible Accounts Retained	(42)	(52)
Total Net Balance Sheet Accounts Receivable	1,066	1,117
Customer Accounts Receivable Securitized	650	507
Total Accounts Receivable Managed	$ 1,716	$ 1,624
Net Uncollectible Accounts Written Off	$ 37	$ 24

Customer accounts receivable retained and securitized for the 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 $22 million and $30 million at December 31, 2008 and 2007, respectively. AEP Credit's delinquent customer accounts receivable represents accounts greater than 30 days past due.

15. 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 options, to 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 last approved the LTIP in 2005. The following sections provide further information regarding each type of stock-based compensation award granted by the Human Resources Committee of the Board of Directors (HR Committee).

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

Stock Options

We did not grant stock options in 2008, 2007 or 2006 but we do have outstanding stock options from grants in earlier periods that vested or were exercised in these years. The exercise price of all outstanding stock options equaled or exceeded the market price of AEP's common stock on the date of grant. All outstanding 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:

	Years Ended December 31,		
	2008	**2007**	**2006**
Stock Options	**(in thousands)**		
Fair Value of Stock Options Vested	$ 25	$ 1,377	$ 3,667
Intrinsic Value of Options Exercised (a)	655	29,389	16,823

(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, 2008, 2007 and 2006 is as follows:

	2008		**2007**		**2006**	
	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,	1,196	$ 32.69	3,670	$ 34.41	6,222	$ 34.16
Granted	-	N/A	-	N/A	-	N/A
Exercised/Converted	(68)	31.97	(2,454)	35.24	(2,343)	33.12
Forfeited/Expired	-	N/A	(20)	35.08	(209)	41.58
Outstanding at December 31,	1,128	32.73	1,196	32.69	3,670	34.41
Options Exercisable at December 31,	1,125	$ 32.72	1,193	$ 32.68	3,411	$ 34.83

The following table summarizes information about AEP stock options outstanding at December 31, 2008.

Options Outstanding

2008 Range of Exercise Prices	Number of Options Outstanding	Weighted Average Remaining Life	Weighted Average Exercise Price	Aggregate Intrinsic Value
	(in thousands)	(in years)		(in thousands)
$27.06 - $27.95	509	4.02	$ 27.39	$ 3,001
$30.76 - $38.65	472	2.83	34.15	375
$44.10 - $49.00	147	2.36	46.71	-
Total (a)	1,128	3.31	32.73	$ 3,376

(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, 2008.

Options Exercisable

2008 Range of Exercise Prices	Number of Options Exercisable	Weighted Average Remaining Life	Weighted Average Exercise Price	Aggregate Intrinsic Value
	(in thousands)	(in years)		(in thousands)
$27.06 - $27.95	509	4.02	$ 27.39	$ 3,001
$30.76 - $38.65	469	2.81	34.12	375
$44.10 - $49.00	147	2.36	46.71	-
Total	1,125	3.30	32.72	$ 3,376

We include the proceeds received from exercised stock options in common stock and paid-in capital.

Performance Units

Our performance units are equal in value to the market value 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 HR Committee and can range from 0% to 200%. 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 that 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 shares of AEP common stock shares and are paid in cash after the participant's termination of employment. Amounts equivalent to cash dividends on both performance units and AEP Career Shares accrue as additional units. We recorded compensation cost for performance units over the three-year vesting period. The liability for both the performance units and AEP Career Shares, recorded in Employee Benefits and Pension Obligations on our Consolidated Balance Sheets, 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 HR Committee awarded performance units and reinvested dividends on outstanding performance units and AEP Career Shares for the years ended December 31, 2008, 2007 and 2006 as follows:

Performance Units	Years Ended December 31, 2008	2007	2006
Awarded Units (in thousands)	1,384	867	1,635
Weighted Average Unit Fair Value at Grant Date	$ 30.11	$ 47.64	$ 39.75
Vesting Period (years)	3	3	3

Performance Units and AEP Career Shares (Reinvested Dividends Portion)	Years Ended December 31, 2008	2007	2006
Awarded Units (in thousands)	149	109	118
Weighted Average Grant Date Fair Value	$ 37.21	$ 45.93	$ 36.87
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 utility companies in the S&P 500 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 2009, the HR Committee certified a performance score for the three-year period ended December 31, 2008 of 120.3%. As a result, 1,088,302 performance units were earned. Of this amount 42,214 were mandatorily deferred as AEP Career Shares, 66,415 were voluntarily deferred into the Incentive Compensation Deferral Program and the remaining units were paid in cash.

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 remaining units 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 remaining units were forfeited due to participant terminations. Of the 917,032 vested units 388,801 were mandatorily deferred as AEP Career Shares and the remaining units were paid in cash.

The cash payouts for the years ended December 31, 2008, 2007 and 2006 were as follows:

	Years Ended December 31, 2008	2007	2006
		(in thousands)	
Cash Payouts for Performance Units	$ 52,960	$ 21,460	$ 2,630
Cash Payouts for AEP Career Share Distributions	1,236	1,348	1,079

Restricted Shares and Restricted Stock Units

The independent members of 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. AEP has not granted other restricted shares. Dividends on these restricted shares are paid in cash.

The HR Committee also grants 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 HR Committee has granted 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 HR Committee granted approximately 12,000 shares of 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 operation. An additional 20% vest one year after the IGCC plant achieves commercial operation, subject to achievement of plant availability targets. The remaining 20% vest two years after the IGCC plant achieves commercial operation, subject to achievement of plant availability targets.

In January 2006, the HR Committee granted approximately 11,000 shares of RSUs with performance vesting conditions related to our IGCC project. Twenty percent of these awards vested on each of the first three anniversaries of the grant date. An additional 20% vest on the date the IGCC plant achieves commercial operation. The remaining 20% vest one year after the IGCC plant achieves commercial operation, subject to achievement of plant availability targets.

In 2008, the HR Committee did not grant RSUs with performance vesting conditions.

The HR Committee awarded RSUs, including units awarded for dividends, for the years ended December 31, 2008, 2007 and 2006 as follows:

	Years Ended December 31,		
Restricted Stock Units	**2008**	**2007**	**2006**
Awarded Units (in thousands)	56	148	65
Weighted Average Grant Date Fair Value	$ 41.69	$ 45.89	$ 37.47

The total fair value and total intrinsic value of restricted shares and restricted stock units vested during the years ended December 31, 2008, 2007 and 2006 were as follows:

	Years Ended December 31,		
	2008	**2007**	**2006**
Restricted Shares and Restricted Stock Units	**(in thousands)**		
Fair Value of Restricted Shares and Restricted Stock Units Vested	$ 2,619	$ 2,711	$ 3,939
Intrinsic Value of Restricted Shares and Restricted Stock Units Vested (a)	2,534	3,646	4,686

(a) Intrinsic value is calculated as market price.

A summary of the status of our nonvested restricted shares and RSUs as of December 31, 2008 and changes during the year ended December 31, 2008 are as follows:

Nonvested Restricted Shares and Restricted Stock Units	Shares/Units (in thousands)		Weighted Average Grant Date Fair Value
Nonvested at January 1, 2008	453	$	36.93
Granted	56		41.69
Vested	(65)		40.19
Forfeited	(1)		42.80
Nonvested at December 31, 2008	443		37.04

The total aggregate intrinsic value of nonvested restricted shares and RSUs as of December 31, 2008 was $14 million and the weighted average remaining contractual life was 2.62 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, 2008, 2007 and 2006.

The Board of Directors awarded stock units, including units awarded for dividends, for the years ended December 31, 2008, 2007 and 2006 as follows:

	Years Ended December 31,					
Stock Unit Accumulation Plan for Non-Employee Directors		**2008**		**2007**		**2006**
Awarded Units (in thousands)		43		28		33
Weighted Average Grant Date Fair Value	$	37.72	$	46.46	$	36.66

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, 2008, 2007 and 2006 were as follows:

	Years Ended December 31,						
		2008			**2007**		**2006**
Share-based Compensation Plans	(in thousands)						
Compensation Cost for Share-based Payment Arrangements (a)	$	(18,028)	(b)	$	72,004	$	45,842
Actual Tax Benefit Realized		(6,310)	(b)		25,201		16,045
Total Compensation Cost Capitalized		(5,026)	(b)		18,077		10,953

(a) Compensation cost for share-based payment arrangements is included in Other Operation and Maintenance on our Consolidated Statements of Income.
(b) In 2008, AEP's declining total shareholder return and lower stock price significantly reduced the accruals for performance units.

During the years ended December 31, 2008, 2007 and 2006, there were no significant modifications affecting any of our share-based payment arrangements.

As of December 31, 2008, there was $70 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 1.78 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, 2008, 2007 and 2006 were as follows:

	Years Ended December 31,		
	2008	2007	2006
Share-based Compensation Plans	(in thousands)		
Cash Received from Stock Options Exercised	$ 2,170	$ 86,527	$ 77,534
Actual Tax Benefit Realized for the Tax Deductions from Stock Options Exercised	219	10,282	5,825

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.

16. PROPERTY, PLANT AND EQUIPMENT

Depreciation, Depletion and Amortization

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:

2008	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	$ 11,650	$ 5,922	1.6 - 3.5%	9 - 132	$ 9,592	$ 3,634	2.6 - 5.1%	20 - 61
Transmission	7,938	2,371	1.4 - 2.7%	25 - 87	-	-	-	-
Distribution	12,816	3,191	2.4 - 3.9%	11 - 75	-	-	-	-
CWIP	2,770	(59)	N.M.	N.M.	1,203	3	N.M.	N.M.
Other	2,705	1,265	4.9 - 11.3%	5 - 55	1,036	396	N.M.	N.M.
Total	$ 37,879	$ 12,690			$ 11,831	$ 4,033		

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	-	-	-	-
Distribution	12,056	3,116	3.0 - 3.9%	11 - 75	-	-	-	-
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		

2006	Regulated		Nonregulated	
Functional Class of Property	**Annual Composite Depreciation Rate Ranges**	**Depreciable Life Ranges**	**Annual Composite Depreciation Rate Ranges**	**Depreciable Life Ranges**
		(in years)		**(in years)**
Production	2.6 - 3.8%	30 - 121	2.57 - 9.15%	20 - 121
Transmission	1.6 - 2.9%	25 - 87	-	-
Distribution	3.0 - 4.0%	11 - 75	-	-
Other	6.7 - 11.5%	24 - 55	N.M.	N.M.

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. Prior to 2008, the lignite mine of DHLC was scheduled to be shut down in May 2011. In December 2007, the LPSC unanimously voted to extend the life of the lignite mine of DHLC through 2016. In December 2008, we received the final order. The average amortization rate for coal rights and mine development costs was $0.26 per ton in 2008 and $0.66 per ton in 2007 and 2006.

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.

Asset Retirement Obligations (ARO)

We record ARO in accordance with SFAS 143 “Accounting for Asset Retirement Obligations” and FIN 47 “Accounting for Conditional Asset Retirement Obligations” for our 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. 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 2008 and 2007 aggregate carrying amounts of ARO:

	Carrying Amount of ARO (in millions)
ARO at December 31, 2006	$ 1,028
Accretion Expense	58
Liabilities Incurred	4
Liabilities Settled	(17)
Revisions in Cash Flow Estimates	5
ARO at December 31, 2007 (a)	1,078
Accretion Expense	60
Liabilities Incurred	22
Liabilities Settled	(34)
Revisions in Cash Flow Estimates	32
ARO at December 31, 2008 (b)	$ 1,158

(a) The current portion of our ARO, totaling $3 million, is included in Other in the Current Liabilities section of our 2007 Consolidated Balance Sheet.
(b) The current portion of our ARO, totaling $4 million, is included in Other in the Current Liabilities section of our 2008 Consolidated Balance Sheet.

As of December 31, 2008 and 2007, our ARO liability was $1.2 billion and $1.1 billion, respectively, and included $891 million and $846 million, respectively, for nuclear decommissioning of the Cook Plant. As of December 31, 2008 and 2007, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $1 billion and $1.1 billion, respectively, relating to the Cook Plant and are recorded in Spent Nuclear Fuel and Decommissioning Trusts on our Consolidated Balance Sheets.

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

Our amounts of allowance for borrowed and equity funds used during construction is summarized in the following table:

	Years Ended December 31,		
	2008	**2007**	**2006**
		(in millions)	
Allowance for Equity Funds Used During Construction	$ 45	$ 33	$ 30
Allowance for Borrowed Funds Used During Construction	75	79	82

Jointly-owned Electric Utility Plants

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, 2008		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress (i)	Accumulated Depreciation
				(in millions)	
W.C. Beckjord Generating Station (Unit No. 6) (a)	Coal	12.5%	$ 18	$ 2	$ 8
Conesville Generating Station (Unit No. 4) (b)	Coal	43.5%	86	173	51
J.M. Stuart Generating Station (c)	Coal	26.0%	478	24	144
Wm. H. Zimmer Generating Station (a)	Coal	25.4%	762	4	344
Dolet Hills Generating Station (Unit No. 1) (d)	Lignite	40.2%	255	1	182
Flint Creek Generating Station (Unit No. 1) (e)	Coal	50.0%	103	10	62
Pirkey Generating Station (Unit No. 1) (e)	Lignite	85.9%	491	8	336
Oklaunion Generating Station (Unit No. 1) (f)	Coal	70.3%	383	7	192
Turk Generating Plant (g)	Coal	73.33%	-	510	-
Transmission	N/A	(h)	70	-	46

			Company's Share at December 31, 2007		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress (i)	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
Turk Generating Plant (g)	Coal	73.33%	-	272	-
Transmission	N/A	(h)	63	6	44

(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) Operated by PSO and also jointly-owned (54.7%) by TNC.
(g) Turk Generating Plant is currently under construction with a projected commercial operation date of 2012. SWEPCo jointly owns the plant with Arkansas Electric Cooperative Corporation (11.67%), East Texas Electric Cooperative (8.33%) and Oklahoma Municipal Power Authority (6.67%). Through December 2008, construction costs totaling $34.8 million have been billed to the other owners.
(h) Varying percentages of ownership.
(i) Primarily relates to construction of Turk Generating Plant and environmental upgrades including the installation of flue gas desulfurization projects at Conesville Generating Station and J.M. Stuart Generating Station.

N/A = Not Applicable

17. 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 net income 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:

	2008 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in millions – except per share amounts)			
Revenues	$ 3,467	$ 3,546	$ 4,191	$ 3,236 (c)
Operating Income	1,043 (a)(b)	586	737	421 (c)
Income Before Discontinued Operations and Extraordinary Loss	573 (a)(b)	280	374	141 (c)
Discontinued Operations, Net of Tax	-	1	-	11
Net Income	573 (a)(b)	281	374	152 (c)
Basic Earnings per Share:				
Earnings per Share Before Discontinued Operations and Extraordinary Loss	1.43	0.70	0.93	0.34
Discontinued Operations per Share	-	-	-	0.03
Earnings per Share	1.43	0.70	0.93	0.37
Diluted Earnings per Share:				
Earnings per Share Before Discontinued Operations and Extraordinary Loss (d)	1.43	0.70	0.93	0.34
Discontinued Operations per Share	-	-	-	0.03
Earnings per Share (e)	1.43	0.70	0.93	0.37

(a) See "TEM Litigation" section of Note 6 for discussion of the settlement reached with TEM in January 2008.
(b) See "Oklahoma 2007 Ice Storms" section of Note 4 for discussion of the first quarter 2008 reversal of expenses incurred from ice storms in January and December 2007.
(c) See "Allocation of Off-system Sales Margins" section of Note 4 for discussion of the financial statement impact of the FERC's November 2008 order related to the SIA.
(d) Amounts for 2008 do not add to $3.39 for Diluted Earnings per Share Before Discontinued Operations and Extraordinary Loss due to rounding.
(e) Amounts for 2008 do not add to $3.42 for Diluted Earnings per Share due to rounding.

	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	545 (f)	549	798	427 (f)
Income Before Discontinued Operations and Extraordinary Loss	271 (f)	257	407	209 (f)
Discontinued Operations, Net of Tax	-	2	-	22
Income Before Extraordinary Loss	271 (f)	259	407	231 (f)
Extraordinary Loss, Net of Tax	-	(79)(g)	-	-
Net Income	271 (f)	180	407	231 (f)
Basic Earnings (Loss) per Share:				
Earnings per Share Before Discontinued Operations and Extraordinary Loss (h)	0.68	0.64	1.02	0.52
Discontinued Operations per Share (i)	-	0.01	-	0.06
Earnings per Share Before Extraordinary Loss	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 and Extraordinary Loss	0.68	0.64	1.02	0.52
Discontinued Operations per Share	-	0.01	-	0.05
Earnings per Share Before Extraordinary Loss	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

(f) See "Oklahoma 2007 Ice Storms" section of Note 4 for discussion of expenses incurred from ice storms in January and December 2007.

(g) See "Virginia Restructuring" in "Extraordinary Item" section of Note 2 for discussion of the extraordinary loss recorded in the second quarter of 2007.

(h) Amounts for 2007 do not add to $2.87 for Basic Earnings per Share Before Discontinued Operations and Extraordinary Loss due to rounding.

(i) Amounts for 2007 do not add to $0.06 for Basic Earnings per Share for Discontinued Operations due to rounding.

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