AMERICAN ELECTRIC POWER CO INC
Form 10-Q
October 31, 2008

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended September 30, 2008
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Transition Period from ____ to ____

Commission File Number	Registrant, State of Incorporation, Address of Principal Executive Offices, and Telephone Number	I.R.S. Employer Identification No.
1-3525	AMERICAN ELECTRIC POWER COMPANY, INC. (A New York Corporation)	13-4922640
1-3457	APPALACHIAN POWER COMPANY (A Virginia Corporation)	54-0124790
1-2680	COLUMBUS SOUTHERN POWER COMPANY (An Ohio Corporation)	31-4154203
1-3570	INDIANA MICHIGAN POWER COMPANY (An Indiana Corporation)	35-0410455
1-6543	OHIO POWER COMPANY (An Ohio Corporation)	31-4271000
0-343	PUBLIC SERVICE COMPANY OF OKLAHOMA (An Oklahoma Corporation)	73-0410895
1-3146	SOUTHWESTERN ELECTRIC POWER COMPANY (A Delaware Corporation)	72-0323455
All Registrants	1 Riverside Plaza, Columbus, Ohio 43215-2373	
	Telephone (614) 716-1000	

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

Yes X No

Indicate by check mark whether American Electric Power Company, Inc. is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of 'large accelerated filer,' 'accelerated filer' and 'smaller reporting company' in Rule 12b-2 of the Exchange Act.

Large accelerated filer X Accelerated filer

Non-accelerated filer Smaller reporting company

Indicate by check mark whether Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company are large accelerated filers, accelerated filers, non-accelerated filers or smaller reporting companies. See the definitions of 'large accelerated filer,' 'accelerated filer' and 'smaller reporting company' in Rule 12b-2 of the Exchange Act.

Large accelerated filer Accelerated filer

Non-accelerated filer X Smaller reporting company

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Exchange Act).
Yes No X

Columbus Southern Power Company and Indiana Michigan Power Company meet the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and are therefore filing this Form 10-Q with the reduced disclosure format specified in General Instruction H(2) to Form 10-Q.

	Number of shares of common stock outstanding of the registrants at October 30, 2008
American Electric Power Company, Inc.	403,554,634
	($6.50 par value)
Appalachian Power Company	13,499,500
	(no par value)
Columbus Southern Power Company	16,410,426
	(no par value)
Indiana Michigan Power Company	1,400,000
	(no par value)
Ohio Power Company	27,952,473
	(no par value)
Public Service Company of Oklahoma	9,013,000
	($15 par value)
Southwestern Electric Power Company	7,536,640
	($18 par value)

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX TO QUARTERLY REPORTS ON FORM 10-Q
September 30, 2008

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

GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an 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.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AFUDC	Allowance for Funds Used During Construction.
ALJ	Administrative Law Judge.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APSC	Arkansas Public Service Commission.
CAA	Clean Air Act.
CO2	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.).
CTC	Competition Transition Charge.
CWIP	Construction Work in Progress.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
DOE	United States Department of Energy.
E&R	Environmental compliance and transmission and distribution system reliability.
EaR	Earnings at Risk, a method to quantify risk exposure.
EITF	Financial Accounting Standards Board's Emerging Issues Task Force.
EPS	Earnings Per Share.
ERCOT	Electric Reliability Council of Texas.
ETT	Electric Transmission Texas, LLC, a 50% equity interest joint venture with MidAmerican Energy Holding Company formed to own and operate electric transmission facilities in ERCOT.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.

FERC	Federal Energy Regulatory Commission.
FIN	FASB Interpretation No.
FIN 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.
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.
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.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
KWH	Kilowatthour.
LPSC	Louisiana Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NOx	Nitrogen oxide.
Nonutility Money Pool	AEP System's Nonutility Money Pool.
NSR	New Source Review.
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.
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.
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 133	Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities."
SNF	Spent Nuclear Fuel.
SO2	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. AEP's 50% interest in Sweeny was sold in October 2007.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TEM	SUEZ Energy Marketing NA, Inc. (formerly known as Tractebel Energy Marketing, Inc.).
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
True-up Proceeding	A filing made under the Texas Restructuring Legislation to finalize the amount of stranded costs and other true-up items and the recovery of such amounts.
Turk Plant	John W. Turk, Jr. Plant.
Utility Money Pool	AEP System's Utility Money Pool.
VaR	Value at Risk, a method to quantify risk exposure.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric distribution subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

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

· Electric load and customer growth.
· Weather conditions, including storms.
· Available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters.
· Availability of generating capacity and the performance of our generating plants.
· Our ability to recover regulatory assets and stranded costs in connection with deregulation.
· Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
· Our ability to build or acquire generating capacity (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (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.
· The economic climate and growth or contraction, in our service territory and changes in market demand and demographic patterns.
· Inflationary and interest rate trends.
· Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impacting our ability to refinance existing debt at attractive rates.
· Our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities.
· Changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading 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.
· 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.
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Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

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

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

EXECUTIVE OVERVIEW

Base Rate Filings

Our significant base rate filings include:

Operating Company	Jurisdiction		Revised Annual Rate Increase Request (in millions)	Projected Effective Date of Rate Increase
APCo	Virginia	$	208	October 2008 (a)
PSO	Oklahoma		117(b)	February 2009
I&M	Indiana		80	June 2009

(a) Subject to refund. An October settlement agreement of $168 million is pending with the Virginia SCC.
(b) Net of estimated amounts that PSO expects to recover through a generation cost recovery rider which will terminate upon implementation of the new base rates.

Ohio Electric Security Plan Filings

In April 2008, the Ohio legislature passed Senate Bill 221, which amends the restructuring law effective July 31, 2008 and requires electric utilities to adjust their rates by filing an Electric Security Plan (ESP). In July 2008, within the parameters of the ESPs, CSPCo and OPCo each requested an annual rate increase for 2009 through 2011 that would not exceed approximately 15% per year.

Credit Markets

In recent months, the world and U.S. economies have experienced significant slowdowns. These economic slowdowns have impacted and will continue to impact our residential, commercial and industrial sales. 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, our liquidity, asset valuations in our trust funds, the creditworthy status of our 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 credit markets could have significant implications on our subsidiaries since they 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 refinance existing debt. Approximately $120 million and $300 million of our $16 billion of long-term debt as of September 30, 2008 will mature in the remainder of 2008 and 2009, respectively. 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 bank having more than 10% of our total bank commitments. In September 2008 and October 2008, we borrowed $600 million and $1.4 billion, respectively, under our credit agreements to enhance our cash position during this period of market disruptions. In October 2008, we also renewed our $600 million sale of receivables agreement through October 2009. At September 30, 2008, our available liquidity was approximately $3 billion.

We cannot predict the length of time the current credit situation will continue or the impact on our future operations and our ability to issue debt at reasonable interest rates. However, when market conditions improve, we plan to repay the amounts drawn under the credit facilities, re-enter the commerical paper market and issue other 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.

We have significant investments in several trust funds to provide for future payments of pensions, OPEB, nuclear decommissioning and spent nuclear fuel disposal. All of our trust funds' investments are well-diversified and managed in compliance with all laws and regulations. The value of the investments in these trusts has declined due to the decreases in the equity and fixed income markets. Although the asset values are currently lower, this has not affected the funds' ability to make their required payments. As of September 30, 2008, the decline in pension asset values will not require us to make a contribution in 2008 or 2009.

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 September 30, 2008, our credit exposure net of collateral was approximately $827 million of which approximately 84% is to investment grade counterparties. At September 30, 2008, our exposure to financial institutions was $145 million, which represents 18% of our total credit exposure net of collateral (all investment grade).

Capital Expenditures

Due to recent credit market instability, we are currently reviewing our projections for capital expenditures from our previous projection of $6.75 billion for 2009 through 2010. We plan to identify reductions of approximately $750 million for 2009. We are evaluating possible additional capital reductions for 2010. We are also reviewing our projections for operation and maintenance expense. Our intent is to keep operation and maintenance expense flat in 2009 as compared to 2008.

Cook Plant Unit 1 Fire and Shutdown

Cook Plant Unit 1 (Unit 1) is a 1,030 MW nuclear generating unit located in Bridgman, Michigan. In September 2008, I&M shut down Unit 1 due to turbine vibrations likely caused by blade failure which resulted in a fire on the electric generator. This equipment is in the turbine building and is separate and isolated from the nuclear reactor. The steam turbines that caused the vibration were installed in 2006 and are under warranty from the vendor. The warranty provides for the replacement of the turbines if the damage was caused by a defect in the design or assembly of the turbines. I&M is also working with its insurance company, Nuclear Electric Insurance Limited (NEIL), and turbine vendor to evaluate the extent of the damage resulting from the incident and the costs to return the unit to service. We cannot estimate the ultimate costs of the outage at this time. 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 preliminary analysis indicates that Unit 1 could resume operations as early as late first quarter/early second quarter of 2009 or as late as the second half of 2009, depending upon whether the damaged components can be repaired or whether they need to be replaced.

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 during the outage period for a covered loss. 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.

Hurricanes

During the third quarter of 2008, our CSPCo, OPCo, SWEPCo and TCC service territories were significantly impacted by Hurricanes Dolly, Gustav and/or Ike. Through September 30, 2008, we had incurred $54 million in total incremental operation and maintenance costs related to the three hurricanes. Since we believe that cost recovery related to the hurricanes is probable for most of these costs in our CSPCo, OPCo, and TCC service territories, we recorded $37 million in regulatory assets for these hurricane costs as of September 30, 2008. We intend to pursue the recovery of $11 million of incremental hurricane costs incurred in our SWEPCo service territory.

New Generation

In May 2006, we announced plans to build the Stall Unit, a new intermediate load, 500 MW, natural gas-fired generating unit at SWEPCo's existing Arsenal Hill Plant location in Shreveport, Louisiana. SWEPCo has received approvals from the Louisiana Public Service Commission (LPSC) and the Public Utility Commission of Texas (PUCT) to construct the Stall Unit and is currently waiting for approval from the APSC. The Stall Unit is estimated to cost $378 million, excluding AFUDC, and is expected to be in-service in mid-2010.

In August 2006, we announced plans to jointly build the Turk Plant, a new base load, 600 MW, pulverized coal, ultra-supercritical generating unit in Arkansas. SWEPCo has received approvals from the APSC and the LPSC to construct the Turk Plant. In August 2008, the PUCT issued an order approving the Turk Plant subject to certain conditions, including the capping of capital costs of the Turk Plant at the $1.5 billion projected construction cost. SWEPCo is also working with the Arkansas Department of Environmental Quality for the approval of an air permit and the U.S. Army Corps of Engineers for the approval of a wetlands and stream impact permit. Once SWEPCo receives the air permit, they will commence construction. The Turk Plant is estimated to cost $1.5 billion, excluding AFUDC, with SWEPCo's portion estimated to cost $1.1 billion. If these permits are approved on a timely basis, the plant is expected to be in-service in 2012.

Fuel Costs

We currently estimate 2008 coal prices to increase by approximately 28% due to escalating domestic prices and increased needs, primarily in the east. We had initially expected coal costs to increase by 13% in 2008. We continue to see increases in prices due to expiring lower-priced coal and transportation contracts being replaced with higher-priced contracts. We have price risk exposure in Ohio, representing approximately 20% of our fuel costs, since we do not have an active fuel cost recovery mechanism. However, under Ohio's amended restructuring law, we have requested the PUCO to reinstate a fuel cost recovery mechanism effective January 1, 2009. Fuel cost adjustment rate clauses in our other jurisdictions will help offset future negative impacts of fuel price increases on our gross margins.

RESULTS OF OPERATIONS

Segments

Our principal operating business 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

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

The table below presents our consolidated Income Before Discontinued Operations and Extraordinary Loss by segment for the three and nine months ended September 30, 2008 and 2007.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(in millions)			
Utility Operations	$ 357	$ 388	$ 1,030	$ 879
AEP River Operations	11	18	21	40
Generation and Marketing	16	3	43	17
All Other (a)	(10)	(2)	133	(1)
Income Before Discontinued Operations and Extraordinary Loss	$ 374	$ 407	$ 1,227	$ 935

(a) All Other includes:

- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.
- 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 liquidate and completely expire in 2011.
- The first quarter of 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 ($163 million, net of tax) is included in Net Income.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

AEP Consolidated

Third Quarter of 2008 Compared to Third Quarter of 2007

Income Before Discontinued Operations and Extraordinary Loss in 2008 decreased $33 million compared to 2007 primarily due to a decrease in Utility Operations segment earnings of $31 million. The decrease in Utility Operations segment earnings primarily relates to an increase in fuel and consumables expense in Ohio and a decrease in cooling degree days throughout our service territories, partially offset by increases in retail margins due to rate increases in Ohio, Virginia, West Virginia, Texas and Oklahoma.

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 403 million as of September 30, 2008.

Nine Months Ended September 30, 2008 Compared to Nine Months Ended September 30, 2007

Income Before Discontinued Operations and Extraordinary Loss in 2008 increased $292 million compared to 2007 primarily due to income of $163 million (net of tax) from the cash settlement received in 2008 related to a power purchase-and-sale agreement with TEM and an increase in Utility Operations segment earnings of $151 million. The increase in Utility Operations segment earnings primarily relates to rate increases implemented since the second quarter of 2007 in Ohio, Virginia, West Virginia, Texas and Oklahoma and higher off-system sales, partially offset by higher interest and fuel expenses.

Average basic shares outstanding increased to 402 million in 2008 from 398 million in 2007 primarily due to the issuance of shares under our incentive compensation and dividend reinvestment plans. Actual shares outstanding were 403 million as of September 30, 2008.

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.

Utility Operations Income Summary
For the Three and Nine Months Ended September 30, 2008 and 2007

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(in millions)			
Revenues	$ 3,968	$ 3,600	$ 10,575	$ 9,587
Fuel and Purchased Power	1,841	1,413	4,428	3,641
Gross Margin	2,127	2,187	6,147	5,946
Depreciation and Amortization	379	374	1,099	1,122
Other Operating Expenses	1,034	1,037	3,001	2,985
Operating Income	714	776	2,047	1,839
Other Income, Net	46	27	135	72
Interest Charges and Preferred Stock Dividend Requirements	225	213	653	599
Income Tax Expense	178	202	499	433
Income Before Discontinued Operations and Extraordinary Loss	$ 357	$ 388	$ 1,030	$ 879

Summary of Selected Sales Data
For Utility Operations
For the Three and Nine Months Ended September 30, 2008 and 2007

	Three Months Ended September 30,		Nine Months Ended September 30,	
Energy/Delivery Summary	2008	2007	2008	2007
	(in millions of KWH)			
Energy				
Retail:				

Residential	12,754	13,749	37,084	38,015
Commercial	10,794	11,164	30,249	30,750
Industrial	14,761	14,697	44,171	43,110
Miscellaneous	668	686	1,916	1,932
Total Retail	38,977	40,296	113,420	113,807
Wholesale	13,130	13,493	35,728	31,648
Delivery				
Texas Wires – Energy delivered to customers served by AEP's Texas Wires Companies	7,961	7,721	20,916	20,297
Total KWHs	60,068	61,510	170,064	165,752

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 associated number of customers within each.

Summary of Weather Data
Summary of Heating and Cooling Degree Days for Utility Operations
For the Three and Nine Months Ended September 30, 2008 and 2007

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(in degree days)			
Weather Summary				
Eastern Region				
Actual – Heating (a)	-	2	1,960	2,041
Normal – Heating (b)	7	7	1,950	1,973
Actual – Cooling (c)	651	808	924	1,189
Normal – Cooling (b)	687	685	969	963
Western Region (d)				
Actual – Heating (a)	-	-	989	994
Normal – Heating (b)	2	2	967	993
Actual – Cooling (c)	1,250	1,406	1,951	2,084
Normal – Cooling (b)	1,402	1,411	2,074	2,084

(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.

Third Quarter of 2008 Compared to Third Quarter of 2007

Reconciliation of Third Quarter of 2007 to Third Quarter of 2008

Income from Utility Operations Before Discontinued Operations and Extraordinary Loss
(in millions)

Third Quarter of 2007		$ 388
Changes in Gross Margin:		
Retail Margins	(81)	
Off-system Sales	(7)	
Transmission Revenues	4	
Other	24	
Total Change in Gross Margin		(60)
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	-	
Depreciation and Amortization	(5)	
Taxes Other Than Income Taxes	2	
Carrying Costs Income	7	
Interest Income	8	
Other Income, Net	5	
Interest and Other Charges	(12)	
Total Change in Operating Expenses and Other		5
Income Tax Expense		24
Third Quarter of 2008		$ 357

Income from Utility Operations Before Discontinued Operations and Extraordinary Loss decreased $31 million to $357 million in 2008. The key drivers of the decrease were a $60 million decrease in Gross Margin offset by a $5 million decrease in Operating Expenses and Other and a $24 million decrease in Income Tax Expense.

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

- Retail Margins decreased $81 million primarily due to the following:
  - A $78 million increase in related to increased fuel and consumable expenses in Ohio. CSPCo and OPCo have applied for an active fuel clause in their Ohio ESP to be effective January 1, 2009.
  - An $80 million decrease in usage primarily due to a 19% decrease in cooling degree days in our eastern region, an 11% decrease in cooling degree days in our western region as well as outages caused by Hurricanes Dolly, Gustav and Ike. Approximately 17% of our reduction in load was attributable to these storms.

  These decreases were partially offset by:
  - A $61 million increase related to net rate increases implemented in our Ohio jurisdictions, an $8 million increase related to recovery of E&R costs in Virginia and the construction financing costs rider in West Virginia, a $6 million increase in base rates in Texas and a $6 million increase in base rates in Oklahoma.
  - A $9 million increase related to increased usage by Ormet, an industrial customer in Ohio. See “Ormet” section of Note 3.
- Margins from Off-system Sales decreased $7 million primarily due to lower trading margins and the favorable effects of a fuel reconciliation recorded in our western service territory in the third quarter of 2007, partially offset

by increases in East physical off-system sales margins due mostly to higher prices.

- Transmission Revenues increased $4 million primarily due to increased rates in the SPP region.
- Other revenues increased $24 million primarily due to increased third-party engineering and construction work and an increase in pole attachment revenue.

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

- Other Operation and Maintenance expenses were flat in comparison to 2007. We experienced decreases related to the following:
  - A $77 million decrease related to the recording of the NSR settlement in the third quarter of 2007. We are evaluating methods to pursue recovery in all 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 expended NSR settlement costs.

  These decreases were offset by:
  - A $24 million increase in non-storm system improvements, customer work and other distribution expenses.
  - A $21 million increase in storm restoration costs, primarily related to Hurricanes Dolly, Gustav and Ike.
  - A $15 million increase in recoverable PJM expenses in Ohio.
  - A $10 million increase in generation plant maintenance.
  - An $8 million increase in recoverable customer account expenses related to the Universal Service Fund for Ohio customers who qualify for payment assistance.
  - An $8 million increase in transmission expenses for tree trimming and reliability.
- Depreciation and Amortization expense increased $5 million primarily due to higher depreciable property balances from the installation of environmental upgrades.
- Carrying Costs Income increased $7 million primarily due to increased carrying cost income on cost deferrals in Virginia and Oklahoma.
- Interest Income increased $8 million primarily due to the favorable effect of claims for refund filed with the IRS.
- Interest and Other Charges increased $12 million primarily due to additional debt issued and higher interest rates on variable rate debt.
- Income Tax Expense decreased $24 million due to a decrease in pretax income.

Nine Months Ended September 30, 2008 Compared to Nine Months Ended September 30, 2007

Reconciliation of Nine Months Ended September 30, 2007 to Nine Months Ended September 30, 2008
Income from Utility Operations Before Discontinued Operations and Extraordinary Loss
(in millions)

Nine Months Ended September 30, 2007		$ 879
Changes in Gross Margin:		
Retail Margins	79	
Off-system Sales	73	
Transmission Revenues	22	
Other Revenues	27	
Total Change in Gross Margin		201

Changes in Operating Expenses and Other:		
Other Operation and Maintenance	11	
Gain on Dispositions of Assets, Net	(18)	
Depreciation and Amortization	23	
Taxes Other Than Income Taxes	(9)	
Carrying Costs Income	26	
Interest Income	25	
Other Income, Net	12	
Interest and Other Charges	(54)	
Total Change in Operating Expenses and Other		16
Income Tax Expense		(66)
Nine Months Ended September 30, 2008		$ 1,030

Income from Utility Operations Before Discontinued Operations and Extraordinary Loss increased $151 million to $1,030 million in 2008. The key drivers of the increase were a $201 million increase in Gross Margin and a $16 million decrease in Operating Expenses and Other offset by a $66 million increase in Income Tax Expense.

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

· Retail Margins increased $79 million primarily due to the following:
  · A $148 million increase related to net rate increases implemented in our Ohio jurisdictions, a $39 million increase related to recovery of E&R costs in Virginia and the construction financing costs rider in West Virginia, a $20 million increase in base rates in Oklahoma and a $17 million increase in base rates in Texas.
  · A $42 million increase related to increased usage by Ormet, an industrial customer in Ohio. See “Ormet” section of Note 3.
  · A $37 million net increase due to adjustments recorded in the prior year related to the 2007 Virginia base rate case which included a second quarter 2007 provision for revenue refund.
  · A $29 million increase due to coal contract amendments in 2008.

  These increases were partially offset by:
  · A $164 million decrease related to increased fuel and consumable expenses in Ohio. CSPCo and OPCo have applied for an active fuel clause in their Ohio ESP to be effective January 1, 2009.
  · A $65 million decrease in usage primarily due to a 22% decrease in cooling degree days in our eastern region and a 6% decrease in cooling degree days in our western region.
  · A $29 million increase in the sharing of off-system sales margins with customers due to an increase in total off-system sales.
· Margins from Off-system Sales increased $73 million primarily due to higher physical off-system sales in our eastern territory as the result of higher volumes and higher prices, aided by additional generation available in 2008 due to fewer planned outages and lower internal load. This increase was partially offset by lower trading margins and the favorable effects of a fuel reconciliation recorded in our western territory in the third quarter of 2007.
· Transmission Revenues increased $22 million primarily due to increased rates in the ERCOT and SPP regions.
· Other Revenues increased $27 million primarily due to increased third-party engineering and construction work, an increase in pole attachment revenue and the recording of an unfavorable

provision for TCC for the refund of bonded rates recorded in 2007.

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

- Other Operation and Maintenance expenses decreased $11 million primarily due to the following:
  - A $77 million decrease related to the recording of NSR settlement costs in September 2007. We are evaluating methods to pursue recovery in all of our affected jurisdictions.
  - A $62 million decrease related to the deferral of Oklahoma storm restoration costs in the first quarter of 2008, net of amortization, as a result of a rate settlement to recover 2007 storm restoration costs.
  - A $19 million decrease in generation plant removal costs.

  These decreases were partially offset by:
  - A $33 million increase in tree trimming, reliability and system improvement expense.
  - A $29 million increase in recoverable PJM expenses in Ohio.
  - A $23 million increase in generation plant operations and maintenance expense.
  - A $21 million increase in recoverable customer account expenses related to the Universal Service Fund for Ohio customers who qualify for payment assistance.
  - A $16 million increase in storm restoration costs, primarily related to Hurricanes Dolly, Gustav and Ike, which occurred in the third quarter of 2008.
  - A $16 million increase in maintenance expense at the Cook Plant.
  - 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 $18 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 $23 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.
- Taxes Other Than Income Taxes increased $9 million primarily due to favorable adjustments to property tax returns recorded in the prior year.
- Carrying Costs Income increased $26 million primarily due to increased carrying cost income on cost deferrals in Virginia and Oklahoma.
- Interest Income increased $25 million primarily due to the favorable effect of claims for refund filed with the IRS.
- Other Income, Net increased $12 million primarily due to an increase in the equity component of AFUDC as a result of new generation projects.
- Interest and Other Charges increased $54 million primarily due to additional debt issued and higher interest rates on variable rate debt.
- Income Tax Expense increased $66 million due to an increase in pretax income.

AEP River Operations

Third Quarter of 2008 Compared to Third Quarter of 2007

Income Before Discontinued Operations and Extraordinary Loss from our AEP River Operations segment decreased to $11 million in 2008 from $18 million in 2007 primarily due to significant disruptions of ship arrivals and departures as the result of an oil spill in the New Orleans Harbor. Ship arrivals were further disrupted by the impacts of Hurricanes Gustav and Ike, which caused severe flooding on the Mississippi and Illinois Rivers. The decrease in income was also due to higher diesel fuel prices. Additionally, decreases in import demand and grain export demand have resulted in lower freight demand, partially offset by increased coal exports.

Nine Months Ended September 30, 2008 Compared to Nine Months Ended September 30, 2007

Income Before Discontinued Operations and Extraordinary Loss from our AEP River Operations segment decreased to $21 million in 2008 from $40 million in 2007 primarily due to significant flooding on various inland waterways throughout 2008 and rising diesel fuel prices. Additionally, decreases in import demand and grain export demand have resulted in lower freight demand, largely the result of a slowing U.S. economy and a weak U.S. dollar. The impact of Hurricanes Gustav and Ike and the oil spill in the New Orleans Harbor, all of which occurred during the third quarter of 2008, also contributed to the unfavorable variance.

Generation and Marketing

Third Quarter of 2008 Compared to Third Quarter of 2007

Income Before Discontinued Operations and Extraordinary Loss from our Generation and Marketing segment increased to $16 million in 2008 from $3 million in 2007 primarily due to higher gross margins from its marketing activities and higher gross margins due to improved price realization, plant performance and hedging activities from its share of the Oklaunion Power Station.

Nine Months Ended September 30, 2008 Compared to Nine Months Ended September 30, 2007

Income Before Discontinued Operations and Extraordinary Loss from our Generation and Marketing segment increased to $43 million in 2008 from $17 million in 2007 primarily due to higher gross margins from its marketing activities and higher gross margins due to improved price realization, plant performance and hedging activities from its share of the Oklaunion Power Station.

All Other

Third Quarter of 2008 Compared to Third Quarter of 2007

Loss Before Discontinued Operations and Extraordinary Loss from All Other increased to $10 million in 2008 from $2 million in 2007. The increase in the loss primarily relates to higher interest expenses due to the issuance of AEP Junior Subordinated Debentures and lower interest income from affiliates.

Nine Months Ended September 30, 2008 Compared to Nine Months Ended September 30, 2007

Income Before Discontinued Operations and Extraordinary Loss from All Other increased to $133 million in 2008 from a $1 million loss in 2007. In 2008, we had after-tax income of $163 million from a litigation settlement of a power purchase and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in the fourth quarter of 2006. The settlement was recorded as a pretax credit to Asset Impairments and Other Related Charges of $255 million in the accompanying Condensed Consolidated Statements of Income. In 2007, we had a $16 million pretax gain ($10 million, net of tax) on the sale of a portion of our investment in Intercontinental Exchange, Inc. (ICE).

AEP System Income Taxes

Income Tax Expense decreased $13 million in the third quarter of 2008 compared to the third quarter of 2007 primarily due to a decrease in pretax income.

Income Tax Expense increased $165 million in the nine-month period ended September 30, 2008 compared to the nine-month period ended September 30, 2007 primarily due to an increase in pretax income.

FINANCIAL CONDITION

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

Debt and Equity Capitalization

	September 30, 2008			December 31, 2007		
			($ in millions)			
Long-term Debt, including amounts due within one year	$	16,007	56.6%	$	14,994	58.1%
Short-term Debt		1,302	4.6		660	2.6
Total Debt		17,309	61.2		15,654	60.7
Common Equity		10,917	38.6		10,079	39.1
Preferred Stock		61	0.2		61	0.2
Total Debt and Equity Capitalization	$	28,287	100.0%	$	25,794	100.0%

Our ratio of debt to total capital increased from 60.7% to 61.2% in 2008 due to our issuance of debt to fund construction and our strategy to deal with the credit situation by drawing cash 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 issuance of long-term debt, sale-leaseback or leasing agreements and common stock.

Credit Markets

In recent months, 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, our liquidity and our cost of capital. The uncertainties in the credit markets could have significant implications on our subsidiaries since they 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 refinance existing debt.

We believe that we have adequate liquidity under our credit facilities. In September 2008, in response to the bankruptcy of certain companies and tightening of credit markets, we borrowed $600 million under our credit lines to assure that cash is available to meet our working capital needs. In October 2008, we borrowed an additional $1.4 billion under our existing credit facilities. We took this proactive step to enhance our cash position during this period of market disruptions.

We cannot predict the length of time the current credit situation will continue or the impact on our future operations and our ability to issue debt at reasonable interest rates. However, when market conditions improve, we plan to repay the amounts drawn under the credit facilities and issue other 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, due to the exposure that bond insurers like Ambac Assurance Corporation and Financial Guaranty Insurance Co. had in connection with developments in the subprime credit market, the credit ratings of those insurers were downgraded or placed on negative outlook. These market factors contributed to higher interest rates in successful auctions and increasing occurrences of failed auctions for tax-exempt long-term debt sold at auction rates, including auctions of our tax-exempt long-term debt. Consequently, we chose to exit the auction-rate debt market. Through September 30, 2008, we reduced our outstanding auction rate securities by $1.2 billion. As of September 30, 2008, we had $272 million outstanding of tax-exempt long-term debt sold at auction rates (rates range between 4.353% and 13%) that reset every 35 days. Approximately $218 million of this debt relates to a lease structure with JMG that we are unable to refinance at this time. In order to refinance this debt, we need the lessor's consent. This debt is insured by the previously AAA-rated bond insurers. The instruments under which the bonds are issued allow us to convert to other short-term variable-rate structures, term-put structures and fixed-rate structures. We plan to continue the conversion and refunding process to other permitted modes, including term-put structures, variable-rate and fixed-rate structures, as opportunities arise. As of September 30, 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 6.5% to 8.25%, $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.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. At September 30, 2008, our available liquidity was approximately $3 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	
Short-term Investments		490	
Cash and Cash Equivalents		338	
Total Liquidity Sources		4,747	
Less: AEP Commercial Paper Outstanding		701	
Cash Drawn on Credit Facilities		591	
Letters of Credit Drawn		439	
Net Available Liquidity	$	3,016	

(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 September 30, 2008, we had credit facilities totaling $3 billion to support our commercial paper program. The maximum amount of commercial paper outstanding during the first nine months of 2008 was $1.2 billion. The weighted-average interest rate of our commercial paper during the first nine months of 2008 was 3.25%.

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 September 30, 2008, $372 million of letters of credit were issued under the 3-year credit agreement to support variable rate demand notes.

Investments in Auction-Rate Securities

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

Sale of Receivables

In October 2008, we renewed our sale of receivables agreement. The sale of receivables agreement provides a commitment of $600 million from bank conduits to purchase receivables. This agreement will expire in October 2009.

Debt Covenants and Borrowing Limitations

Our revolving credit agreements, including the new agreements entered into in April 2008, contain certain covenants and require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating our outstanding debt and other capital is contractually defined. At September 30, 2008, this contractually-defined percentage was 57.3%. Nonperformance of these covenants could result in an event of default under these credit agreements. At September 30, 2008, we complied with all of the covenants contained in these credit agreements. In addition, the acceleration of our payment obligations, or the obligations of certain of our major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million, would cause an event of default under these credit agreements and permit the lenders to declare the outstanding amounts payable.

Our 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 September 30, 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. The Board of Directors declared a quarterly dividend of $0.41 per share in October 2008. Future dividends may vary depending upon our profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. We have the option to defer interest payments on the $315 million of AEP Junior Subordinated Debentures issued in March 2008 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 net income, cash flows, financial condition or limit any dividend payments in the foreseeable future.

Credit Ratings

In the first quarter of 2008, Moody's changed its outlook from stable to negative for APCo, SWEPCo, OPCo and TCC and affirmed its stable outlook for AEP and our other rated subsidiaries. Also in the first quarter, Fitch downgraded PSO and SWEPCo from A- to BBB+ for senior unsecured debt. In May 2008, Fitch revised APCo's outlook from stable to negative. Our current credit ratings are as follows:

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

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

Cash Flow

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

	Nine Months Ended September 30,	
	2008	2007
	(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 178	$ 301
Net Cash Flows from Operating Activities	2,053	1,630
Net Cash Flows Used for Investing Activities	(3,061)	(2,935)
Net Cash Flows from Financing Activities	1,168	1,200
Net Increase (Decrease) in Cash and Cash Equivalents	160	(105)
Cash and Cash Equivalents at End of Period	$ 338	$ 196

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

	Nine Months Ended September 30,	
	2008	2007
	(in millions)	
Net Income	$ 1,228	$ 858
Less: Discontinued Operations, Net of Tax	(1)	(2)
Income Before Discontinued Operations	1,227	856
Depreciation and Amortization	1,123	1,144
Other	(297)	(370)
Net Cash Flows from Operating Activities	$ 2,053	$ 1,630

Net Cash Flows from Operating Activities increased in 2008 primarily due to the TEM settlement.

Net Cash Flows from Operating Activities were $2.1 billion in 2008 consisting primarily of Income Before Discontinued Operations of $1.2 billion and $1.1 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 include an increase in under-recovered fuel reflecting higher coal and natural gas prices.

Net Cash Flows from Operating Activities were $1.6 billion in 2007 consisting primarily of Income Before Discontinued Operations of $856 million and $1.1 billion of noncash Depreciation and Amortization. Other represents items that had a prior 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 a number of items, the most significant of which relates primarily to the Texas CTC refund of fuel over-recovery.

Investing Activities

	Nine Months Ended September 30, 2008	2007
	(in millions)	
Construction Expenditures	$ (2,576)	$ (2,595)
Purchases/Sales of Investment Securities, Net	(474)	217
Acquisition of Assets	(97)	(512)
Proceeds from Sales of Assets	83	78
Other	3	(123)
Net Cash Flows Used for Investing Activities	$ (3,061)	$ (2,935)

Net Cash Flows Used for Investing Activities were $3.1 billion in 2008 primarily due to Construction Expenditures for our environmental, distribution and new generation investment plan.

Net Cash Flows Used for Investing Activities were $2.9 billion in 2007 primarily due to Construction Expenditures for our environmental, distribution and new generation investment plan. We paid $512 million to purchase gas-fired generating units to acquire capacity at a cost below that of building a new, comparable plant.

In our normal course of business, we purchase and sell investment securities with cash available for short-term investments including the cash drawn against our credit facilities in 2008. We also purchase and sell investment securities within our nuclear trusts.

We forecast approximately $1.2 billion of construction expenditures for the remainder of 2008. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital. These construction expenditures will be funded through cash flows from operations and financing activities.

Financing Activities

	Nine Months Ended September 30, 2008	2007
	(in millions)	
Issuance of Common Stock	$ 106	$ 116
Issuance/Retirement of Debt, Net	1,621	1,623
Dividends Paid on Common Stock	(494)	(467)
Other	(65)	(72)
Net Cash Flows from Financing Activities	$ 1,168	$ 1,200

Net Cash Flows from Financing Activities in 2008 were $1.2 billion primarily due to the issuance of additional debt including $315 million of Junior Subordinated Debentures and a net increase of $1.3 billion in outstanding Senior Unsecured Notes partially offset, by the reacquisition of a net $370 million of Pollution Control Bonds and $125 million of Securitization Bonds. In September 2008, we borrowed $600 million under our credit agreements. See Note 9 – Financing Activities for a complete discussion of long-term debt issuances and retirements.

Net Cash Flows from Financing Activities in 2007 were $1.2 billion primarily due to issuing $1.9 billion of debt securities including $1 billion of new debt for plant acquisitions and construction and increasing short-term commercial paper borrowings.

Off-balance Sheet Arrangements

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

	September 30, 2008		December 31, 2007	
	(in millions)			
AEP Credit Accounts Receivable Purchase Commitments	$	555	$	507
Rockport Plant Unit 2 Future Minimum Lease Payments		2,142		2,216
Railcars Maximum Potential Loss From Lease Agreement		26		30

For complete information on each of these off-balance sheet arrangements see the “Off-balance Sheet Arrangements” section of “Management’s Financial Discussion and Analysis of Results of Operations” in the 2007 Annual Report.

Summary Obligation Information

A summary of our contractual obligations is included in our 2007 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in “Cash Flow” above and the drawdowns and standby letters of credit discussed in “Liquidity” above.

SIGNIFICANT FACTORS

We continue to be involved in various matters described in the “Significant Factors” section of “Management’s Financial Discussion and Analysis of Results of Operations” in our 2007 Annual Report. The 2007 Annual Report should be read in conjunction with this report in order to understand significant factors which have not materially changed in status since the issuance of our 2007 Annual Report, but may have a material impact on our future net income, cash flows and financial condition.

Ohio Electric Security Plan Filings

In April 2008, the Ohio legislature passed Senate Bill 221, which amends the restructuring law effective July 31, 2008 and requires electric utilities to adjust their rates by filing an Electric Security Plan (ESP). Electric utilities may file an ESP with a fuel cost recovery mechanism. Electric utilities also have an option to file a Market Rate Offer (MRO) for generation pricing. An MRO, from the date of its commencement, could transition 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 or modify the utilities' ESP request. The PUCO is required to approve an ESP if, in the aggregate, the ESP is more favorable to ratepayers than the MRO. Both alternatives involve a "substantially excessive earnings" test based on what public companies, including other utilities with similar risk profiles, earn on equity. Management has preliminarily concluded, pending the outcome of the ESP proceeding, that CSPCo's and OPCo's generation/supply operations are not subject to cost-based rate regulation accounting. However, if a fuel cost recovery mechanism is implemented within the ESP, CSPCo's and OPCo's fuel and purchased power operations would be subject to cost-based rate regulation accounting. 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.

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 and OPCo each requested an annual rate increase for 2009 through 2011 that would not exceed approximately 15% per year. A significant portion of the requested increases results from the implementation of a fuel cost recovery mechanism (which excludes off-system sales) that primarily includes fuel costs, purchased power costs including mandated renewable energy, consumables such as urea, other variable production costs and gains and losses on sales of emission allowances. The increases in customer bills related to the fuel-purchased power cost recovery mechanism would be phased-in over the three year period from 2009 through 2011. If the ESP is approved as filed, effective with January 2009 billings, CSPCo and OPCo will defer any fuel cost under-recoveries and related carrying costs for future recovery. The under-recoveries and related carrying costs that exist at the end of 2011 will be recovered over seven years from 2012 through 2018. In addition to the fuel cost recovery mechanisms, the requested 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 programs for smart metering initiatives and economic development and mandated energy efficiency and peak demand reduction programs. In September 2008, the PUCO issued a finding and order tentatively adopting rules governing MRO and ESP applications. CSPCo and OPCo filed their ESP applications based on proposed rules and requested waivers for portions of the proposed rules. The PUCO denied the waiver requests in September 2008 and ordered CSPCo and OPCo to submit information consistent with the tentative rules. In October 2008, CSPCo and OPCo submitted additional information related to proforma financial statements and information concerning CSPCo and OPCo's fuel procurement process. In October 2008, CSPCo and OPCo filed an application for rehearing with the PUCO to challenge certain aspects of the proposed rules.

Within the ESPs, CSPCo and OPCo would also recover existing regulatory assets of $46 million and $38 million, respectively, for customer choice implementation and line extension carrying costs. In addition, CSPCo and OPCo would recover related unrecorded equity carrying costs of $30 million and $21 million, respectively. Such costs would be recovered over an 8-year period beginning January 2011. Hearings are scheduled for November 2008 and an order is expected in the fourth quarter of 2008. If an order is not received prior to January 1, 2009, CSPCo and OPCo have requested retroactive application of the new rates back to January 1, 2009 upon approval. Failure of the PUCO to ultimately approve the recovery of the regulatory assets would have an adverse effect on future net income and cash flows.

Cook Plant Unit 1 Fire and Shutdown

Cook Plant Unit 1 (Unit 1) is a 1,030 MW nuclear generating unit located in Bridgman, Michigan. In September 2008, I&M shut down Unit 1 due to turbine vibrations likely caused by blade failure which resulted in a fire on the electric generator. This equipment is in the turbine building and is separate and isolated from the nuclear reactor. The steam turbines that caused the vibration were installed in 2006 and are under warranty from the vendor. The warranty provides for the replacement of the turbines if the damage was caused by a defect in the design or assembly of the turbines. I&M is also working with its insurance company, Nuclear Electric Insurance Limited (NEIL), and turbine vendor to evaluate the extent of the damage resulting from the incident and the costs to return the unit to service. We cannot estimate the ultimate costs of the outage at this time. 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 preliminary analysis indicates that Unit 1 could resume operations as early as late first quarter/early second quarter of 2009 or as late as the second half of 2009, depending upon whether the damaged components can be repaired or whether they need to be replaced.

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 during the outage period for a covered loss. 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.

TCC 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 over a period ending in 2020. TCC has refunded its net other true-up regulatory liabilities of $375 million during the period October 2006 through June 2008 via a CTC credit rate rider. Cash paid for these CTC refunds for the nine months ended September 30, 2008 and 2007 was $75 million and $207 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 one major respect. It reversed the district court's unfavorable decision finding that the PUCT erred by applying an invalid rule to determine the carrying cost rate. The favorable commercial unreasonableness decision 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.

Management cannot predict the outcome of these court proceedings and PUCT remand decisions. If TCC ultimately succeeds 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) (in millions)	CWIP (b) (in millions)	Fuel Type	Plant Type	Nominal MW Capacity	Commercial Operation Date (Projected)
PSO	Southwestern(c)	Oklahoma	$ 56	$ -	Gas	Simple-cycle	150	2008

PSO	Riverside	(d)	Oklahoma	58	-	Gas	Simple-cycle	150	2008
AEGCo	Dresden	(e)	Ohio	309(h)	149	Gas	Combined-cycle	580	2010(h)
SWEPCo	Stall		Louisiana	378	158	Gas	Combined-cycle	500	2010
SWEPCo	Turk	(f)	Arkansas	1,522(f)	448	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 $1.1 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 necessary permits and regulatory approval. See "IGCC Plants" section below.
(h) Projected completion date of the Dresden Plant is currently under review. To the extent that the completion date is delayed, the total projected cost of the Dresden Plant could change.

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 $1.5 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. An intervenor filed a motion for rehearing seeking reversal of the PUCT's decision. SWEPCo filed a motion for rehearing stating that the two cost cap restrictions are unlawful. In September 2008, the motions for rehearing were denied. 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.

SWEPCo is also working with the Arkansas Department of Environmental Quality for the approval of an air permit and the U.S. Army Corps of Engineers for the approval of a wetlands and stream impact permit. Once SWEPCo receives the air permit, they will commence construction. A request to stop pre-construction activities at the site was filed in federal court by the same Arkansas landowners who appealed the APSC decision to the Arkansas State Court of Appeals. In July 2008, the federal court denied the request and the Arkansas landowners appealed the denial to the U.S. Court of Appeals.

In January 2008 and July 2008, SWEPCo filed applications for authority 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. The landowner filed an appeal to the Arkansas State Court of Appeals in June 2008.

The Arkansas Governor's Commission on Global Warming is scheduled to issue its final report to the Governor by November 1, 2008. The Commission was established to set a global warming pollution reduction goal together with a strategic plan for implementation in Arkansas. 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 September 30, 2008, SWEPCo has capitalized approximately $448 million of expenditures and has significant contractual construction commitments for an additional $771 million. As of September 30, 2008, if the plant had been cancelled, cancellation fees of $61 million would have been required in order to terminate these construction commitments. 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 necessary permits and regulatory approvals. In May 2008, the Virginia SCC denied APCo's request to reconsider the Virginia SCC's previous denial of 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. 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 September 30, 2008, APCo deferred for future recovery preconstruction IGCC costs of $19 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, 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.

Litigation

In the ordinary course of business, we, along with our subsidiaries, are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual outcome will be, or what the timing of the amount of any loss, fine or penalty may be. Management does, however, assess the probability of loss for such contingencies and accrues a liability for cases that have a probable likelihood of loss and if the loss amount can be estimated. For details on our regulatory proceedings and pending litigation see Note 4 – Rate Matters, Note 6 – Commitments, Guarantees and Contingencies and the "Litigation" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2007 Annual Report. Additionally, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies included herein. 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, OPCo and other nonaffiliated utilities, including Cincinnati Gas & Electric Company, Dayton Power and Light Company (DP&L) and Duke Energy Ohio, Inc. (Duke), modified certain units at coal-fired generating plants in violation of the NSR requirements of the CAA.

In 2007, the AEP System settled their complaints under a consent decree. CSPCo jointly-owns Beckjord and Stuart Stations with Duke and DP&L. A jury trial in May 2008 returned a verdict of no liability at the jointly-owned Beckjord unit. In October 2008, the court approved a settlement in the 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 NOx, SO2 and PM. We 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 SO2 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 new environmental control requirements. The sources of these requirements include:

- Requirements under CAA to reduce emissions of SO2, NOx, PM and mercury from fossil fuel-fired power plants; and
- Requirements under the Clean Water Act (CWA) to reduce the impacts of water intake structures on aquatic species at certain of our power plants.

In addition, we are engaged in litigation with respect to certain environmental matters, have been notified of potential responsibility for the clean-up of contaminated sites and incur costs for disposal of spent nuclear fuel and future decommissioning of our nuclear units. We are also engaged in the development of possible future requirements to reduce CO2 and other greenhouse gas (GHG) emissions to address concerns about global climate change. All of these matters are discussed in the “Environmental Matters” section of “Management’s Financial Discussion and Analysis of Results of Operations” in the 2007 Annual Report.

Clean Air Act Requirements

As discussed in the 2007 Annual Report under “Clean Air Act Requirements,” various states and environmental organizations challenged the Clean Air Mercury Rule (CAMR) 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. The court vacated and remanded the model 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. We are unable to predict the outcome of this appeal or how the Federal EPA will respond to the remand. In addition, in 2005, the Federal EPA issued a final rule, the Clean Air Interstate Rule (CAIR), that requires further reductions in SO2 and NOx emissions and assists states developing new state implementation plans to meet 1997 national ambient air quality standards (NAAQS). CAIR reduces regional emissions of SO2 and NOx (which can be transformed into PM and ozone) from power plants in the Eastern U.S. (29 states and the District of Columbia). CAIR requires power plants within these states to reduce emissions of SO2 by 50% by 2010, and by 65% by 2015. NOx emissions will be subject to additional limits beginning in 2009, and will be reduced by a total of 70% from current levels by 2015. Reduction of both SO2 and NOx would be achieved through a cap-and-trade program. In July 2008, the D.C. Circuit Court of Appeals vacated the CAIR and remanded the rule to the Federal EPA. The Federal EPA and other parties petitioned for rehearing. We are unable to predict the outcome of the rehearing petitions or how the Federal EPA will respond to the remand which could be stayed or appealed to the U.S. Supreme Court. The Federal EPA also issued revised NAAQS for both ozone and PM 2.5 that are more stringent than the 1997 standards used to establish CAIR, which could increase the levels of SO_2 and NO_x reductions required from our facilities.

In anticipation of compliance with CAIR in 2009, I&M purchased $9 million of annual CAIR NO_x allowances which are included in Deferred Charges and Other on our Condensed Consolidated Balance Sheet as of September 30, 2008. The market value of annual CAIR NO_x allowances decreased following this court decision. However, our weighted-average cost of these allowances is below market. If CAIR remains vacated, management intends to seek partial recovery of the cost of purchased allowances. Any unrecovered portion would have an adverse effect on future net income and cash flows. None of AEP's other subsidiaries purchased any significant number of CAIR allowances. SO_2 and seasonal NO_x allowances allocated to our facilities under the Acid Rain Program and the NO_x state implementation plan (SIP) Call will still be required to comply with existing CAA programs that were not affected by the court's decision.

It is too early to determine the full implication of these decisions on our environmental compliance strategy. However, independent obligations under the CAA, including obligations under future state implementation plan submittals, and actions taken pursuant to our settlement of the NSR enforcement action, are consistent with the actions included in our least-cost CAIR compliance plan. Consequently, we do not anticipate making any immediate changes in our near-term compliance plans as a result of these court decisions.

Global Climate Change

In July 2008, the Federal EPA issued an advance notice of proposed rulemaking (ANPR) that requests comments on a wide variety of issues the agency is considering in formulating its response to the U.S. Supreme Court's decision in Massachusetts v. EPA. In that case, the court determined that CO_2 is an "air pollutant" and that the Federal EPA has authority to regulate mobile sources of CO_2 emissions under the CAA if appropriate findings are made. The Federal EPA has identified a number of issues that could affect stationary sources, such as electric generating plants, if the necessary findings are made for mobile sources, including the potential regulation of CO_2 emissions for both new and existing stationary sources under the NSR programs of the CAA. We plan to submit comments and participate in any subsequent regulatory development processes, but are unable to predict the outcome of the Federal EPA's administrative process or its impact on our business. Also, additional legislative measures to address CO_2 and other GHGs have been introduced in Congress, and such legislative actions could impact future decisions by the Federal EPA on CO_2 regulation.

In addition, the Federal EPA issued a proposed rule for the underground injection and storage of CO_2 captured from industrial processes, including electric generating facilities, under the Safe Drinking Water Act's Underground Injection Control (UIC) program. The proposed rules provide a comprehensive set of well siting, design, construction, operation, closure and post-closure care requirements. We plan to submit comments and participate in any subsequent regulatory development process, but are unable to predict the outcome of the Federal EPA's administrative process or its impact on our business. Permitting for our demonstration project at the Mountaineer Plant will proceed under the existing UIC rules.

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

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.

Critical Accounting Estimates

See the "Critical Accounting Estimates" section of "Management's Financial Discussion and Analysis of Results of Operations" in the 2007 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and the impact of new accounting pronouncements.

Adoption of New Accounting Pronouncements

In September 2006, the FASB issued SFAS 157 "Fair Value Measurements" (SFAS 157), enhancing existing guidance for fair value measurement of assets and liabilities and instruments measured at fair value that are classified in shareholders' equity. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures. It emphasizes that fair value is market-based with the highest measurement hierarchy level being market prices in active markets. The standard requires fair value measurements be disclosed by hierarchy level, an entity includes its own credit standing in the measurement of its liabilities and modifies the transaction price presumption. The standard also nullifies the consensus reached in EITF Issue No. 02-3 "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-3) that prohibited the recognition of trading gains or losses at the inception of a derivative contract, unless the fair value of such derivative is supported by observable market data. In February 2008, the FASB issued 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" which amends SFAS 157 to exclude SFAS 13 "Accounting for Leases" and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement under SFAS 13. In February 2008, the FASB issued FSP SFAS 157-2 "Effective Date of FASB Statement No. 157" which delays the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). 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 provisions of SFAS 157 are applied prospectively, except for a) changes in fair value measurements of existing derivative financial instruments measured initially using the transaction price under EITF 02-3, b) existing hybrid financial instruments measured initially at fair value using the transaction price and c) blockage discount factors. Although the statement is applied prospectively upon adoption, in accordance with the provisions of SFAS 157 related to EITF 02-3, we recorded an immaterial transition adjustment to beginning retained earnings. The impact of considering our own credit risk when measuring the fair value of liabilities, including derivatives, had an immaterial impact on fair value measurements upon adoption. We partially adopted SFAS 157 effective January 1, 2008. FSP SFAS 157-3 is effective upon issuance. We will fully adopt SFAS 157 effective January 1, 2009 for items within the scope of FSP SFAS 157-2. We expect that the adoption of FSP SFAS 157-2 will have an immaterial impact on our financial statements. See "SFAS 157 "Fair Value Measurements"

(SFAS 157)" section of Note 2.

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

In March 2007, the FASB ratified EITF Issue No. 06-10 "Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements" (EITF 06-10), a consensus on collateral assignment split-dollar life insurance arrangements in which an employee owns and controls the insurance policy. Under EITF 06-10, an employer should recognize a liability for the postretirement benefit related to a collateral assignment split-dollar life insurance arrangement in accordance with SFAS 106 "Employers' Accounting for Postretirement Benefits Other Than Pension" or Accounting Principles Board Opinion No. 12 "Omnibus Opinion – 1967" if the employer has agreed to maintain a life insurance policy during the employee's retirement or to provide the employee with a death benefit based on a substantive arrangement with the employee. In addition, an employer should recognize and measure an asset based on the nature and substance of the collateral assignment split-dollar life insurance arrangement. EITF 06-10 requires recognition of the effects of its application as either (a) a change in accounting principle through a cumulative effect adjustment to retained earnings or other components of equity or net assets in the statement of financial position at the beginning of the year of adoption or (b) a change in accounting principle through retrospective application to all prior periods. We adopted EITF 06-10 effective January 1, 2008 with a cumulative effect reduction of $16 million ($10 million, net of tax) to beginning retained earnings.

In June 2007, the FASB ratified the EITF Issue No. 06-11 "Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards" (EITF 06-11), consensus on the treatment of income tax benefits of dividends on employee share-based compensation. The issue is how a company should recognize the income tax benefit received on dividends that are paid to employees holding equity-classified nonvested shares, equity-classified nonvested share units or equity-classified outstanding share options and charged to retained earnings under SFAS 123R, "Share-Based Payments." Under EITF 06-11, a realized income tax benefit from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for equity-classified nonvested equity shares, nonvested equity share units and outstanding equity share options should be recognized as an increase to additional paid-in capital. We adopted EITF 06-11 effective January 1, 2008. EITF 06-11 is applied prospectively to the income tax benefits of dividends on equity-classified employee share-based payment awards that are declared in fiscal years after December 15, 2007. The adoption of this standard had an immaterial impact on our financial statements.

In April 2007, the FASB issued FSP FIN 39-1 "Amendment of FASB Interpretation No. 39" (FIN 39-1). It amends FASB Interpretation No. 39 "Offsetting of Amounts Related to Certain Contracts" by replacing the interpretation's definition of contracts with the definition of derivative instruments per SFAS 133. It also requires entities that offset fair values of derivatives with the same party under a netting agreement to net the fair values (or approximate fair values) of related cash collateral. The entities must disclose whether or not they offset fair values of derivatives and related cash collateral and amounts recognized for cash collateral payables and receivables at the end of each reporting period. We adopted FIN 39-1 effective January 1, 2008. This standard changed our method of netting certain balance sheet amounts and reduced assets and liabilities. It requires retrospective application as a change in accounting principle. Consequently, we reduced total assets and liabilities on the December 31, 2007 balance sheet by $47 million each. See "FSP FIN 39-1 "Amendment of FASB Interpretation No. 39" (FIN 39-1)" section of Note 2.

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 liquidate and completely expire in 2011. Our risk objective is to keep these positions generally risk neutral through maturity.

We employ risk management contracts including physical forward purchase and sale contracts and financial forward purchase and sale contracts. We engage in risk management of electricity, natural gas, coal and emissions and to a lesser degree other commodities associated with our energy business. As a result, we are subject to price risk. The amount of risk taken is determined by the commercial operations group in accordance with the market risk policy approved by the Finance Committee of our Board of Directors. Our market risk oversight staff independently monitors our risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (CORC) various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. The CORC consists of our President – AEP Utilities, Chief Financial Officer, Senior Vice President of Commercial Operations and Chief Risk Officer. When commercial activities exceed predetermined limits, we modify the positions to reduce the risk to be within the limits unless specifically approved by the CORC.

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 Condensed Consolidated Balance Sheet as of September 30, 2008 and the reasons for changes in our total MTM value included on our Condensed Consolidated Balance Sheet as compared to December 31, 2007.

Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheet
September 30, 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	$ 246	$ 52	$ 43	$ 341	$ 25	$ (26)	$ 340
Noncurrent Assets	164	128	40	332	6	(24)	314
Total Assets	410	180	83	673	31	(50)	654
Current Liabilities	(209)	(65)	(47)	(321)	(18)	9	(330)
Noncurrent Liabilities	(69)	(57)	(43)	(169)	(4)	8	(165)
Total Liabilities	(278)	(122)	(90)	(490)	(22)	17	(495)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 132	$ 58	$ (7)	$ 183	$ 9	$ (33)	$ 159

MTM Risk Management Contract Net Assets (Liabilities)
Nine Months Ended September 30, 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	(57)	4	1	(52)
Fair Value of New Contracts at Inception When Entered During the Period (a)	2	17	-	19
Changes in Fair Value Due to Valuation Methodology Changes on Forward Contracts (b)	3	3	1	7
Changes in Fair Value Due to Market Fluctuations During the Period (c)	18	(9)	(1)	8
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	10	-	-	10
Total MTM Risk Management Contract Net Assets (Liabilities) at September 30, 2008	$ 132	$ 58	$ (7)	183
Net Cash Flow and Fair Value Hedge Contracts				9

Collateral Deposits		(33)
Ending Net Risk Management Assets at September 30, 2008	$	159

(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 Condensed 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 September 30, 2008
(in millions)

	Remainder 2008	2009	2010	2011	2012	After 2012 (f)	Total
Utility Operations:							
Level 1 (a)	$ (2)	$ (8)	$ -	$ -	$ -	$ -	$ (10)
Level 2 (b)	5	62	43	5	1	-	116
Level 3 (c)	(15)	2	(6)	1	1	-	(17)
Total	(12)	56	37	6	2	-	89
Generation and Marketing:							
Level 1 (a)	(1)	-	-	-	-	-	(1)
Level 2 (b)	(21)	2	11	12	11	20	35
Level 3 (c)	5	2	3	2	2	10	24
Total	(17)	4	14	14	13	30	58
All Other:							
Level 1 (a)	-	-	-	-	-	-	-
Level 2 (b)	(1)	(4)	(4)	2	-	-	(7)
Level 3 (c)	-	-	-	-	-	-	-
Total	(1)	(4)	(4)	2	-	-	(7)
Total:							
Level 1 (a)	(3)	(8)	-	-	-	-	(11)
Level 2 (b)	(17)	60	50	19	12	20	144
Level 3 (c) (d)	(10)	4	(3)	3	3	10	7
Total	(30)	56	47	22	15	30	140
Dedesignated Risk Management Contracts (e)	4	14	14	6	5	-	43

Total MTM Risk Management Contract Net Assets (Liabilities)	$ (26)	$ 70	$ 61	$ 28	$ 20	$ 30	$ 183

(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 contract.
(f) There is mark-to-market value of $30 million in individual periods beyond 2012. $14 million of this mark-to-market value is in 2013, $8 million is in 2014, $3 million is in 2015, $2 million is in 2016 and $3 million is in 2017.

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

We are exposed to market fluctuations in energy commodity prices impacting our power 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 Condensed Consolidated Balance Sheets and the reasons for changes in cash flow hedges from December 31, 2007 to September

30, 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.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Nine Months Ended September 30, 2008
(in millions)

	Power	Interest Rate and Foreign Currency	Total
Beginning Balance in AOCI, December 31, 2007	$ (1)	$ (25)	$ (26)
Changes in Fair Value	7	(5)	2
Reclassifications from AOCI for Cash Flow Hedges Settled	2	3	5
Ending Balance in AOCI, September 30, 2008	$ 8	$ (27)	$ (19)
After Tax Portion Expected to be Reclassified to Earnings During Next 12 Months	$ 6	$ (5)	$ 1

Credit Risk

We limit credit risk in our wholesale marketing and trading activities by assessing creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness after transactions have been initiated. We use Moody’s Investors Service, Standard & Poor’s and qualitative and quantitative data to assess the financial health of counterparties on an ongoing basis. 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 September 30, 2008, our credit exposure net of collateral to sub investment grade counterparties was approximately 14.5%, 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). The increase from 5.4% at December 31, 2007 is primarily related to an increase in exposure with coal counterparties. Approximately 57% of our credit exposure net of collateral to sub investment grade counterparties is short-term exposure of less than one year. As of September 30, 2008, the following table approximates our counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable (in millions, except number of counterparties):

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties >10% of Net Exposure	Net Exposure of Counterparties >10%
Investment Grade	$ 626	$ 42	$ 584	2	$ 146
Split Rating	14	-	14	2	14

Noninvestment Grade	81	8	73	2	66
No External Ratings:					
Internal Investment Grade	110	-	110	2	77
Internal Noninvestment Grade	46	-	46	2	40
Total as of September 30, 2008	$ 877	$ 50	$ 827	10	$ 343
Total as of December 31, 2007	$ 673	$ 42	$ 631	6	$ 74

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 September 30, 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 periods indicated:

VaR Model

Nine Months Ended September 30, 2008 (in millions)				Twelve Months Ended December 31, 2007 (in millions)			
End	High	Average	Low	End	High	Average	Low
$2	$3	$1	$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 historically-based method whereby the current portfolio is subjected to actual, observed price moves from the last three years in order to ascertain which historical price moves translates into the largest potential mark-to-market loss. We 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. The estimated EaR on our debt portfolio was $51 million.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2008 and 2007
(in millions, except per-share amounts and shares outstanding)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2008	2007	2008	2007
REVENUES				
Utility Operations	$ 4,108	$ 3,423	$ 10,318	$ 9,127
Other	83	366	886	977
TOTAL	4,191	3,789	11,204	10,104
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	1,480	1,099	3,513	2,853
Purchased Electricity for Resale	394	358	1,023	895
Other Operation and Maintenance	1,010	964	2,870	2,783
Gain on Disposition of Assets, Net	(6)	(2)	(14)	(28)
Asset Impairments and Other Related Charges	-	-	(255)	-
Depreciation and Amortization	387	381	1,123	1,144
Taxes Other Than Income Taxes	189	191	578	565
TOTAL	3,454	2,991	8,838	8,212
OPERATING INCOME	737	798	2,366	1,892
Other Income:				
Interest and Investment Income	14	8	45	39
Carrying Costs Income	21	14	64	38
Allowance For Equity Funds Used During Construction	11	9	32	23
INTEREST AND OTHER CHARGES				
Interest Expense	216	216	670	615
Preferred Stock Dividend Requirements of Subsidiaries	1	1	2	2
TOTAL	217	217	672	617
INCOME BEFORE INCOME TAX EXPENSE, MINORITY INTEREST EXPENSE AND EQUITY EARNINGS	566	612	1,835	1,375
Income Tax Expense	192	205	608	443
Minority Interest Expense	1	1	3	3
Equity Earnings of Unconsolidated Subsidiaries	1	1	3	6
INCOME BEFORE DISCONTINUED OPERATIONS AND EXTRAORDINARY LOSS	374	407	1,227	935
DISCONTINUED OPERATIONS, NET OF TAX	-	-	1	2
INCOME BEFORE EXTRAORDINARY LOSS	374	407	1,228	937

EXTRAORDINARY LOSS, NET OF TAX		-		-		-		(79)
NET INCOME	$	374	$	407	$	1,228	$	858