from over-the-counter brokers (OTC), industry services, or multiple-party on-line platforms.

(b) Prices Based on Models and Other Valuation Methods is in the absence of pricing information from external sources, modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity is limited, such valuations are classified as modeled.

(c) There is mark-to-market value in excess of 10 percent of our total mark-to-market value in individual periods beyond 2009. $26 million of this mark-to-market value is in 2010.

(d) Amounts exclude Cash Flow and Fair Value Hedges.

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

Maximum Tenor of the Liquid Portion of Risk Management Contracts
As of September 30, 2005

Commodity	Transaction Class	Market/Region	Tenor (in months)
Natural Gas	Futures	NYMEX/Henry Hub	60
	Physical Forwards	Gulf Coast, Texas	27
	Swaps	Gas East - Northeast, Mid-continent, Gulf Coast, Texas	27
	Swaps	Gas West - Rocky Mountains, West Coast	27
	Exchange Option Volatility	NYMEX/Henry Hub	12
Power	Futures	Power East - PJM	39
	Physical Forwards	Power East - MISO Cin Hub	27
	Physical Forwards	Power East - PJM West	39
	Physical Forwards	Power East - AEP Dayton (PJM)	15
	Physical Forwards	Power East - NEPOOL	39
	Physical Forwards	Power East - NYPP	39
	Physical Forwards	Power East - ERCOT	39
	Physical Forwards	Power East - Com Ed	9
	Physical Forwards	Power East - Entergy	15
	Physical Forwards	Power West - Palo Verde, Mead	51
	Physical Forwards	Power West - North Path 15, South Path 15	51
	Physical Forwards	Power West - Mid Columbia	51
	Peak Power Volatility (Options)	Cinergy, PJM	12
Emissions	Credits	SO_2, NO_x	39

Coal	Physical Forwards	PRB, NYMEX, CSX	27

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

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

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

The tables below provide detail on designated, effective cash flow hedges included in our Condensed Consolidated Balance Sheets. The data in the first table indicates the magnitude of cash flow hedges that we have in place. 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. This table further indicates what portions of designated, effective hedges are expected to be reclassified into net income in the next 12 months. The second table provides the nature of changes from December 31, 2004 to September 30, 2005.

Information on energy commodity risk management activities is presented separately from interest rate risk management activities.

Cash Flow Hedges included in Accumulated Other Comprehensive Income (Loss)
On the Condensed Consolidated Balance Sheet as of September 30, 2005
(in millions)

	Accumulated Other Comprehensive Income (Loss) After Tax (a)	After Tax Portion Expected to be Reclassified to Earnings During the Next 12 Months (b)
Power and Gas	$ (42)	$ (42)
Interest Rate	(25)	(3)
Total	$ (67)	$ (45)

Total Accumulated Other Comprehensive Income (Loss) Activity
Nine Months Ended September 30, 2005
(in millions)

	Power and Gas	Interest Rate	Total
Beginning Balance, December 31, 2004	$ 23	$ (23)	$ -
Changes in Fair Value (c)	(41)	(5)	(46)
Reclassifications from AOCI to Net Income (d)	(24)	3	(21)
Ending Balance, September 30, 2005	$ (42)	$ (25)	$ (67)

(a) "Accumulated Other Comprehensive Income (Loss) After Tax" - Gains/losses are net of related income taxes that have not yet been included in the determination of net income; reported as a separate component of shareholders' equity on the balance sheet.

(b) "After Tax Portion Expected to be Reclassified to Earnings During the Next 12 Months" - Amount of gains or losses (realized or unrealized) from derivatives used as hedging instruments that have been deferred and are expected to be reclassified into net income during the next 12 months at the time the hedged transaction affects net income.

(c) "Changes in Fair Value" - Changes in the fair value of derivatives designated as cash flow hedges during the reporting period that are not yet settled at September 30, 2005. Amounts are reported net of related income taxes.

(d) "Reclassifications from AOCI to Net Income" - Gains or losses from derivatives used as hedging instruments in cash flow hedges that were reclassified into Net Income during the reporting period. Amounts are reported net of related income taxes.

Credit Risk

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

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. At September 30, 2005, our credit exposure net of collateral to sub investment grade counterparties was approximately 13.22%, expressed in terms of net MTM assets and net receivables. As of September 30, 2005, the following table approximates our counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable (in millions, except number of counterparties):

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%

Investment Grade	$	1,149	$	359	$	790	3	$	342
Split Rating		25		9		16	1		15
Noninvestment Grade		316		222		94	3		81
No External Ratings:									
Internal Investment Grade		113		1		112	1		51
Internal Noninvestment Grade		48		1		47	2		35
Total	$	1,651	$	592	$	1,059	10	$	524

Generation Plant Hedging Information

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

Generation Plant Hedging Information
Estimated Next Three Years
As of September 30, 2005

	Remainder 2005	2006	2007
Estimated Plant Output Hedged	94%	89%	90%

VaR Associated with Risk Management Contracts

We use a risk measurement model, which calculates 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, 2005, a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

The following table shows the end, high, average, and low market risk as measured by VaR year-to-date:

VaR Model

Nine Months Ended September 30, 2005 (in millions)				Twelve Months Ended December 31, 2004 (in millions)			
End	High	Average	Low	End	High	Average	Low
$4	$5	$2	$1	$3	$19	$5	$1

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

CCRO VaR Metrics
(in millions)

	September 30, 2005	Average for Year-to-Date 2005	High for Year-to-Date 2005	Low for Year-to-Date 2005
95% Confidence Level, Ten-Day Holding Period	$ 15	$ 9	$ 20	$ 5
99% Confidence Level, One-Day Holding Period	$ 6	$ 4	$ 8	$ 2

We utilize a VaR model to measure interest rate market risk exposure. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one-year holding period. The volatilities and correlations were based on three years of daily prices. The risk of potential loss in fair value attributable to our exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $593 million at September 30, 2005 and $601 million at December 31, 2004. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not materially affect our results of operations, cash flows or financial position.

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

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2005 and 2004
(in millions, except per-share amounts)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2005	2004	2005	2004
REVENUES				
Utility Operations	$ 3,132	$ 2,920	$ 8,318	$ 8,009
Gas Operations	73	760	449	2,191
Other	95	101	289	356
TOTAL	3,300	3,781	9,056	10,556
EXPENSES				
Fuel for Electric Generation	1,011	782	2,554	2,210
Purchased Electricity for Resale	181	274	494	444
Purchased Gas for Resale	5	725	255	2,011
Maintenance and Other Operation	906	847	2,569	2,689
Asset Impairments and Other Related Charges	39	-	39	-
Depreciation and Amortization	336	333	988	972
Taxes Other Than Income Taxes	205	181	566	555
TOTAL	2,683	3,142	7,465	8,881
OPERATING INCOME	617	639	1,591	1,675
Other Income	139	208	484	329
Other Expense	(24)	(36)	(130)	(110)
Investment Value Losses	(7)	-	(7)	(2)
INTEREST AND OTHER CHARGES				
Interest Expense	163	193	524	591
Preferred Stock Dividend Requirements of Subsidiaries	1	2	6	5
TOTAL	164	195	530	596
INCOME BEFORE INCOME TAXES	561	616	1,408	1,296
Income Taxes	196	204	471	444
INCOME BEFORE DISCONTINUED OPERATIONS	365	412	937	852

DISCONTINUED OPERATIONS, Net of Tax		22		118		26		60
NET INCOME	$	387	$	530	$	963	$	912
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING		389		396		389		396
BASIC EARNINGS PER SHARE								
Income Before Discontinued Operations	$	0.94	$	1.04	$	2.41	$	2.15
Discontinued Operations		0.05		0.30		0.07		0.15
TOTAL BASIC EARNINGS PER SHARE	$	0.99	$	1.34	$	2.48	$	2.30
WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING		390		397		390		396
DILUTED EARNINGS PER SHARE								
Income Before Discontinued Operations	$	0.94	$	1.04	$	2.40	$	2.15
Discontinued Operations		0.05		0.30		0.07		0.15
TOTAL DILUTED EARNINGS PER SHARE	$	0.99	$	1.34	$	2.47	$	2.30
CASH DIVIDENDS PAID PER SHARE	$	0.35	$	0.35	$	1.05	$	1.05

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2005 and December 31, 2004
(in millions)
(Unaudited)

	2005	2004
CURRENT ASSETS		
Cash and Cash Equivalents	$ 849	$ 320
Other Temporary Cash Investments	73	275
Accounts Receivable:		
Customers	829	930
Accrued Unbilled Revenues	369	592
Miscellaneous	45	79
Allowance for Uncollectible Accounts	(33)	(77)
Total Accounts Receivable	1,210	1,524
Fuel, Materials and Supplies	649	852
Risk Management Assets	1,318	737
Margin Deposits	357	113
Other	214	200
TOTAL	4,670	4,021
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	16,487	15,969
Transmission	6,400	6,293
Distribution	10,564	10,280
Other (including gas, coal mining and nuclear fuel)	3,072	3,585
Construction Work in Progress	1,676	1,159
Total	38,199	37,286
Accumulated Depreciation and Amortization	14,684	14,485
TOTAL - NET	23,515	22,801
OTHER NONCURRENT ASSETS		
Regulatory Assets	3,852	3,601
Securitized Transition Assets	608	642
Spent Nuclear Fuel and Decommissioning Trusts	1,120	1,053
Investments in Power and Distribution Projects	105	154
Goodwill	76	76
Long-term Risk Management Assets	918	470
Prepaid Pension Obligations	382	386

Other	663	831
TOTAL	7,724	7,213
Assets Held for Sale	47	628
TOTAL ASSETS	$ 35,956	$ 34,663

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
September 30, 2005 and December 31, 2004
(Unaudited)

	2005	2004
CURRENT LIABILITIES	(in millions)	
Accounts Payable	$ 1,112	$ 1,051
Short-term Debt	15	23
Long-term Debt Due Within One Year (a)	717	1,279
Cumulative Preferred Stocks of Subsidiaries Subject to Mandatory Redemption	-	66
Risk Management Liabilities	1,280	608
Accrued Taxes	729	611
Accrued Interest	160	180
Customer Deposits	725	414
Other	674	775
TOTAL	5,412	5,007
NONCURRENT LIABILITIES		
Long-term Debt (a)	11,025	11,008
Long-term Risk Management Liabilities	741	329
Deferred Income Taxes	4,674	4,819
Regulatory Liabilities and Deferred Investment Tax Credits	2,847	2,540
Asset Retirement Obligations	847	827
Employee Benefits and Pension Obligations	461	730
Deferred Gain on Sale and Leaseback - Rockport Plant Unit 2	159	166
Deferred Credits and Other	742	411
TOTAL	21,496	20,830
Liabilities Held for Sale	2	250
TOTAL LIABILITIES	26,910	26,087
Cumulative Preferred Stock Not Subject to Mandatory Redemption	61	61

Commitments and Contingencies (Note 5)

COMMON SHAREHOLDERS' EQUITY

Common Stock Par Value $6.50:

	2005	2004
Shares Authorized	600,000,000	600,000,000

Shares Issued	414,959,884	404,858,145		
(21,499,992 and 8,999,992 shares were held in treasury at September 30, 2005 and December 31, 2004, respectively)			2,697	2,632
Paid-in Capital			4,121	4,203
Retained Earnings			2,579	2,024
Accumulated Other Comprehensive Income (Loss)			(412)	(344)
TOTAL			8,985	8,515
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY			$ 35,956	$ 34,663

(a) See Accompanying Schedule.

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2005 and 2004
(in millions)
(Unaudited)

	2005	2004
OPERATING ACTIVITIES		
Net Income	$ 963	$ 912
Less: Income from Discontinued Operations	(26)	(60)
Income from Continuing Operations	937	852
Adjustments for Noncash Items:		
Depreciation and Amortization	988	972
Accretion of Asset Retirement Obligations	50	47
Deferred Income Taxes	(33)	88
Deferred Investment Tax Credits	(23)	(21)
Asset Impairments, Investment Value Losses and Other Related Charges	46	2
Carrying Costs	(83)	(2)
Amortization of Deferred Property Taxes	94	92
Mark-to-Market of Risk Management Contracts	-	89
Pension Contributions	(306)	(27)
Over/Under Fuel Recovery	(183)	78
Gain on Sales of Assets	(172)	(156)
Change in Other Noncurrent Assets	(99)	(101)
Change in Other Noncurrent Liabilities	(21)	27
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	5	367
Fuel, Materials and Supplies	54	(18)
Accounts Payable	204	(289)
Taxes Accrued	118	388
Customer Deposits	311	19
Interest Accrued	(25)	(25)
Other Current Assets	(246)	(107)
Other Current Liabilities	(29)	3
Net Cash Flows From Operating Activities	1,587	2,278
INVESTING ACTIVITIES		
Acquisition of Waterford Plant	(218)	-
Construction Expenditures	(1,610)	(1,047)
Change in Other Temporary Cash Investments, Net	99	28
Investment in Discontinued Operations, Net	-	(59)
Purchases of Investments	(3,342)	(425)
Proceeds from the Sale of Investments	3,445	274

Proceeds from Sale of Assets	1,599	1,202
Other	39	(6)
Net Cash Flows From (Used For) Investing Activities	12	(33)
FINANCING ACTIVITIES		
Issuance of Common Stock	393	13
Repurchase of Common Stock	(427)	-
Issuance of Long-term Debt	2,045	416
Change in Short-term Debt, Net	(8)	(201)
Retirement of Long-term Debt	(2,599)	(1,898)
Retirement of Preferred Stock	(66)	(4)
Dividends Paid on Common Stock	(408)	(415)
Net Cash Flows Used For Financing Activities	(1,070)	(2,089)
Net Increase in Cash and Cash Equivalents	529	156
Cash and Cash Equivalents at Beginning of Period	320	778
Cash and Cash Equivalents at End of Period	$ 849	$ 934
Net Decrease in Cash and Cash Equivalents from Discontinued Operations	$ -	$ (4)
Cash and Cash Equivalents from Discontinued Operations - Beginning of Period	-	13
Cash and Cash Equivalents from Discontinued Operations - End of Period	$ -	$ 9

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 30, 2005 and 2004
(in millions)
(Unaudited)

	Common Stock				Accumulated Other	
	Shares	Amount	Paid-in Capital	Retained Earnings	Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	404	$ 2,626	$ 4,184	$ 1,490	$ (426)	$ 7,874
Issuance of Common Stock	1	4	9			13
Common Stock Dividends				(415)		(415)
Other			4			4
TOTAL						7,476
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss) Net of Tax:						
Foreign Currency Translation Adjustments, Net of Tax of $0					(113)	(113)
Cash Flow Hedges, Net of Tax of $4					(8)	(8)
Minimum Pension Liability, Net of Tax of $10					16	16
NET INCOME				912		912
TOTAL COMPREHENSIVE INCOME						807
SEPTEMBER 30, 2004	405	$ 2,630	$ 4,197	$ 1,987	$ (531)	$ 8,283
DECEMBER 31, 2004	405	$ 2,632	$ 4,203	$ 2,024	$ (344)	8,515
Issuance of Common Stock	10	65	328			393
Common Stock Dividends				(408)		(408)
Repurchase of Common Stock			(427)			(427)
Other			17			17
TOTAL						8,090
COMPREHENSIVE INCOME						
Other Comprehensive Income (Loss) Net of Tax:						
Foreign Currency Translation Adjustments,						

Net of Tax of $0					(6)	(6)
Cash Flow Hedges, Net of Tax of $36					(67)	(67)
Minimum Pension Liability, Net of Tax of $0					4	4
Securities Available for Sale, Net of Tax $0					1	1
NET INCOME				963		963
TOTAL COMPREHENSIVE INCOME						895
SEPTEMBER 30, 2005	415	$ 2,697	$ 4,121	$ 2,579	$ (412)	$ 8,985

:e Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED SCHEDULE OF CONSOLIDATED LONG-TERM DEBT
September 30, 2005 and December 31, 2004
(Unaudited)
(in millions)

	2005	2004
First Mortgage Bonds	$ 242	$ 417
Defeased TCC First Mortgage Bonds (a)	18	84
Installment Purchase Contracts	1,935	1,773
Notes Payable	919	939
Senior Unsecured Notes	7,342	7,717
Securitization Bonds	648	698
Notes Payable to Trust	113	113
Equity Unit Senior Notes (b)	345	345
Long-term DOE Obligation (c)	234	229
Other Long-term Debt	-	14
Equity Unit Contract Adjustment Payments	-	9
Unamortized Discount, Net	(54)	(51)
TOTAL LONG-TERM DEBT OUTSTANDING	11,742	12,287
Less Portion Due Within One Year	717	1,279
TOTAL LONG-TERM PORTION	$ 11,025	$ 11,008

(a) On May 7, 2004, we deposited cash and treasury securities of $125 million with a trustee to defease all of TCC's outstanding First Mortgage Bonds. Trust fund assets related to this obligation of $2 and $72 million are included in Other Temporary Cash Investments at September 30, 2005 and December 31, 2004, respectively, and $21 and $22 million are included in Other Noncurrent Assets in the Condensed Consolidated Balance Sheets at September 30, 2005 and December 31, 2004, respectively. Trust fund assets are restricted for exclusive use in funding the interest and principal due on the First Mortgage Bonds.

(b) In June 2005, we remarketed $345 million of 5.75% Equity Unit Senior Notes originally issued in June 2002 with new notes bearing a 4.709% interest rate. See "Remarketing of Senior Notes" section of Note 11.

(c) Pursuant to the Nuclear Waste Policy Act of 1982, I&M (a nuclear licensee) has an obligation with the United States Department of Energy for spent nuclear fuel disposal. The obligation includes a one-time fee for nuclear fuel consumed prior to April 7, 1983. I&M is the only AEP subsidiary that generated electric power with nuclear fuel prior to that date. Trust fund assets of $265 million and $262 million related to this obligation are included in Spent Nuclear Fuel and Decommissioning Trusts in the Condensed Consolidated Balance Sheets at September 30, 2005 and December 31, 2004, respectively.

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

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

1. SIGNIFICANT ACCOUNTING MATTERS

General

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

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

Other Income and Other Expense

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
	(in millions)		(in millions)	
Other Income:				
Interest and Dividend Income	$ 18	$ 7	$ 43	$ 18
Equity Earnings	3	5	10	15
Nonutility Revenue	16	27	108	85
Gain on Sale of IPPs	-	105	-	105
Gain on Sale of South Coast	-	48	-	48
Gain on Sale of Pac Hydro (a)	56	-	56	-
Gain on Sale of Texas REPs (a)	-	-	112	-
Carrying Charges	27	1	83	2
Other	19	15	72	56
Total Other Income	$ 139	$ 208	$ 484	$ 329
Other Expense:				
Nonutility Expense	$ 12	$ 24	$ 90	$ 75
Other	12	12	40	35
Total Other Expense	$ 24	$ 36	$ 130	$ 110

(a) See "Dispositions" section of Note 7.

Components of Accumulated Other Comprehensive Income (Loss)

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

Components	September 30, 2005	December 31, 2004
	(in millions)	
Foreign Currency Translation Adjustments, Net of tax	$ -	$ 6
Securities Available for Sale, Net of tax	-	(1)
Cash Flow Hedges, Net of tax	(67)	-
Minimum Pension Liability, Net of tax	(345)	(349)
Total	$ (412)	$ (344)

At September 30, 2005, we expect to reclassify approximately $45 million of net losses from cash flow hedges in Accumulated Other Comprehensive Income (Loss) to Net Income during the next twelve months at the time the hedged transactions affect Net Income. The actual amounts that are reclassified from Accumulated Other Comprehensive Income (Loss) to Net Income can differ as a result of market fluctuations. Fifteen months is the maximum length of time that we are hedging our exposure to variability in future cash flows with contracts designated as cash flow hedges.

Accounting for Asset Retirement Obligations (ARO)

The following is a reconciliation of the beginning and ending aggregate carrying amounts of ARO:

	Nuclear Decommissioning	Ash Ponds	Wind Mills and Mining Operations	Total
		(in millions)		
ARO at January 1, 2005, Including STP	$ 960	$ 84	$ 32	$ 1,076
Accretion Expense	43	5	2	50
Liabilities Incurred	-	-	8	8
Revisions in Cash Flow Estimates	(27)(c)	-	(1)	(28)
ARO at September 30, 2005, Including STP	976	89	41	1,106
Less ARO Liability for STP (a)	(256)	-	-	(256)
ARO at September 30, 2005	$ 720	$ 89	$ 41	$ 850(b)

(a) The ARO for TCC's share of STP was included in Liabilities Held for Sale at December 31, 2004 and was subsequently transferred to the buyer with the sale in the second quarter of 2005 (see "Texas Plants-South Texas Project" section of Note 7).

(b) The current portion of our ARO, totaling $3 million, is included in Other in the Current Liabilities section in our Condensed Consolidated Balance Sheets.
(c) The Cook Plant's operating licenses were renewed for Cook Unit 1 until 2034 and for Cook Unit 2 until 2037.

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

At September 30, 2005 and December 31, 2004, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $855 million and $791 million, respectively, relating to Cook Plant recorded in Spent Nuclear Fuel and Decommissioning Trusts in our Condensed Consolidated Balance Sheets.

Supplementary Information

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
Related Party Transactions	(in millions)			
AEP Consolidated Purchased Power:				
Ohio Valley Electric Corporation (44.2% owned)	$ 49	$ 45	$ 140	$ 115
Sweeny Cogeneration Limited Partnership (50% owned)	38	-	98	-

	Nine Months Ended September 30,	
	2005	2004
Cash Flow Information	(in millions)	
Cash was paid (received) for:		
Interest (net of capitalized amounts)	$ 492	$ 576
Income Taxes	277	(112)
Change in construction-related Accounts Payable included in Investing Activities - Construction Expenditures	66	(24)
Noncash Investing and Financing Activities: Acquisitions Under Capital Leases	42	90
(Disposition) of Liabilities Related to Acquisitions/Divestures, Net	(20)	(67)

Earnings per Share

The following tables present our basic and diluted earnings per share (EPS) calculations included in our Condensed Consolidated Statements of Income:

Three Months Ended September 30,	
2005	2004

	(In Millions, Except Per Share Data)			
		$/share		$/share
Earnings applicable to common stock	$ 387		$ 530	
Average number of basic shares outstanding	388.9	$ 0.99	395.7	$ 1.34
Average dilutive effect of:				
Performance Share Units	1.0	(0.00)	0.7	(0.00)
Stock Options	0.5	(0.00)	0.3	(0.00)
Restricted Stock Units	0.1	(0.00)	-	(0.00)
Average number of diluted shares outstanding	390.5	$ 0.99	396.7	$ 1.34

	Nine Months Ended September 30,			
	2005		2004	
	(In Millions, Except Per Share Data)			
		$/share		$/share
Earnings applicable to common stock	$ 963		$ 912	
Average number of basic shares outstanding	388.7	$ 2.48	395.6	$ 2.30
Average dilutive effect of:				
Performance Share Units	0.9	(0.01)	0.5	(0.00)
Stock Options	0.3	(0.00)	0.3	(0.00)
Restricted Stock Units	0.1	(0.00)	-	(0.00)
Average number of diluted shares outstanding	390.0	$ 2.47	396.4	$ 2.30

Our stock option and other equity compensation plans are discussed in Note 12 to the consolidated financial statements in the 2004 Form 10-K.

Reclassifications

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

In connection with preparation of the first quarter of 2005 financial statements, we concluded that it was appropriate to classify our auction rate securities as Other Temporary Cash Investments. Previously, such investments had been classified as Cash and Cash Equivalents in the Condensed Consolidated Balance Sheets. Accordingly, we have revised the classification to exclude from Cash and Cash Equivalents $103 million at December 31, 2004, and to include such amounts as Other Temporary Cash Investments. There were no auction rate securities held at September 30, 2005. At December 31, 2003, auction rate securities approximated $200 million. These revisions had no impact on our previously reported results of operations, operating cash flows or working capital.

2. NEW ACCOUNTING PRONOUNCEMENTS

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

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

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

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

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

SFAS 154 "Accounting Changes and Error Corrections" (SFAS 154)

In May 2005, the FASB issued SFAS 154, which replaces APB Opinion No. 20, "Accounting Changes," and SFAS No. 3, "Reporting Accounting Changes in Interim Financial Statements." The statement applies to all voluntary changes in accounting principle and changes resulting from adoption of a new accounting pronouncement that does not specify transition requirements. SFAS 154 requires retrospective application to prior periods' financial statements for changes in accounting principle unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS 154 also requires that retrospective application of a change in accounting principle be limited to the direct effects of the change. Indirect effects of a change in accounting principle should be recognized in the period of the accounting change. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005 with early implementation permitted for accounting changes and corrections of errors made in fiscal years beginning after the date this statement is issued. SFAS 154 is effective for us beginning January 1, 2006 and will be applied when applicable.

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

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

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

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

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

Future Accounting Changes

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

3. RATE MATTERS

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

APCo Virginia Environmental and Reliability Costs

In April 2004, the Virginia Electric Restructuring Act was amended to include a provision that permits recovery, during the extended capped rate period ending December 31, 2010, of incremental environmental compliance and transmission and distribution (T&D) system reliability (E&R) costs prudently incurred after July 1, 2004. On July 1, 2005, APCo filed a request with the Virginia SCC seeking approval for the recovery of $62 million in incremental E&R costs through June 30, 2006. The $62 million request represents i) expected costs of environmental controls on coal-fired generators to meet the first phase of the Clean Air Interstate Rule and Clean Air Mercury Rule finalized earlier this year, ii) recovery of the incremental cost of the Jacksons Ferry-Wyoming 765 kilovolt transmission line construction and iii) other incremental T&D system reliability costs incurred from July 1, 2004 to June 30, 2006.

In the filing, APCo had requested that a twelve-month E&R recovery factor be applied to electric service bills on an interim basis beginning August 1, 2005. The recovery factor would have been applied as a 9.18% surcharge to customer bills. APCo proposed to practice over/under-recovery deferral accounting for the difference between the actual incremental costs incurred and the revenue recovered.

Through September 30, 2005, APCo has incurred approximately $13 million of actual incremental E&R costs and has deferred $7 million of such costs for future recovery. APCo did not record $2 million of equity carrying costs that are not recognized until collected. Additionally, E&R costs of $4 million represented capitalized interest that was duplicative of the carrying costs.

On July 14, 2005, the Virginia SCC issued an order that established a procedural schedule for APCo's proceeding including a public hearing on February 7, 2006. The order provided that no portion of APCo's application should become effective pending further decision of the Virginia SCC. On October 14, 2005, the Virginia SCC denied APCo's request to place in effect, on an interim basis subject to refund, its proposed cost recovery surcharge. Under this order, an E&R surcharge will not become effective until the Virginia SCC issues an order following the February 7, 2006 public hearing in this case. The Virginia SCC also ruled in this order that it does not have the authority under applicable Virginia law to approve the recovery of projected E&R costs before their actual incurrence and adjudication, which effectively eliminated projected costs requested in this filing. However, according to this order, APCo may update its request to reflect additional actual costs and/or present additional evidence. If the Virginia SCC denies recovery of any portion of the net incremental amounts deferred to date, it would adversely affect future results of operations and cash flows.

APCo and WPCo West Virginia Rate Case

On August 26, 2005, APCo and WPCo collectively filed an application with the Public Service Commission of West Virginia seeking an initial increase in their retail rates of approximately $82 million. The initial increase included approval to reactivate and modify the suspended Expanded Net Energy Cost (ENEC) Recovery Mechanism which accounted for $72 million of the initial increase and approval to implement a system reliability tracker which accounted for $10 million. ENEC includes fuel and purchased power costs, as well as other energy-related items including off-system sales margins and transmission items. In addition, APCo and WPCo requested a series of supplemental annual increases related to the recovery of the cost of significant environmental and transmission expenditures. The first proposed supplemental increase of $9 million would go in effect on the same date as the initial rate increase, and the remaining proposed supplemental increases of $44 million, $10 million and $38 million would go in effect on January 1, 2007, 2008 and 2009, respectively. It is expected that the proposed rates will become effective on June 23, 2006 under West Virginia law. APCo has a regulatory liability of $52 million of pre-suspension, previously over-recovered ENEC costs which it is proposing to apply plus a carrying cost in the future to any under-recoveries of ENEC costs through the reactivated ENEC Recovery Mechanism. Management is unable to predict the ultimate effect of this filing on future revenues, results of operations, cash flows and financial condition.

I&M Indiana Settlement Agreement

I&M's fuel and base rates in Indiana were frozen through a prior agreement. In 2004, the IURC ordered the continuation of the fixed fuel adjustment charge on an interim basis through March 2005, pending the outcome of negotiations. Certain of the parties to the negotiations reached a settlement and signed an agreement on March 10, 2005 and filed the agreement with the IURC on March 14, 2005. The IURC approved the agreement on June 1, 2005.

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

The settlement agreement also covers certain events at the Cook Plant. The settlement provides that if an outage of greater than 60 days occurs at Cook Plant, the recovery of actual monthly fuel costs will be in effect for the outage period beyond 60 days, capped by the average AEP System Pool Primary Energy Rate (Primary Energy Rate), the ratio of the sum of fuel and one half maintenance expenses incurred by the pool members to the total kilowatt-hours of net generation, excluding I&M, as defined by the AEP System Interconnection Agreement and adjusted for losses. If a second outage greater than 60 days occurs, actual monthly fuel costs capped at the Primary Energy Rate would be recovered through June 2007. Over the term of the settlement, if total cumulative actual fuel costs (except during a Cook Plant outage of greater than 60 days) are less than the cap prices, the savings will be credited to customers over the next two fuel adjustment clause filings. Cumulative net fuel costs in excess of the capped prices cannot be recovered. If Cook Plant operates at a capacity factor greater than 87% during the fuel cap period, I&M will receive credit for 30% of the savings produced by that performance.

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

I&M experienced a cumulative under-recovery for the period March 2004 through September 2005 of $10 million. Since I&M expects that its cumulative fuel costs through the end of the fuel cap period will exceed the capped fuel rates, the $10 million was recorded as fuel expense. If future fuel costs per KWH through June 30, 2007 continue to exceed the caps, or if the base rate cap precludes I&M from seeking timely rate increases to recover increases in its cost of service through June 30, 2007, future results of operations and cash flows would be adversely affected.

I&M Michigan Fuel Recovery Plan

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

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

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

On September 30, 2005, I&M filed its 2006 PSCR Plan reflecting projected costs for 2006. The factors proposed by I&M will be placed into effect beginning January 2006 on an interim basis, unless approved by the MPSC prior to that time. If approved, the fuel factors to be placed in effect together with accompanying over/under-recovery deferral accounting should allow I&M to recover its fuel costs in Michigan.

KPCo Rate Filing

On September 26, 2005, KPCo filed a request with the Kentucky Public Service Commission to increase base rates by approximately $65 million to recover increasing costs. The major components of the rate increase include a return on common equity of 11.5% or $26 million, the impact of reduced point-to-point transmission revenues of $10 million, recovery of additional AEP Power Pool capacity costs of $9 million, additional reliability spending of $7 million and increased depreciation expense of $5 million. A final order is expected in April 2006. We are unable to predict the ultimate effect of this filing on future revenues, results of operations, cash flows and financial condition.

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

In 2002, PSO experienced a $44 million under-recovery of fuel costs resulting from a reallocation among AEP West companies of purchased power costs for periods prior to January 1, 2002. In July 2003, PSO offered to the OCC to collect those reallocated costs over 18 months. In August 2003, the OCC Staff filed testimony recommending PSO recover $42 million of the reallocation of purchased power costs over three years. In September 2003, the OCC expanded the case to include a full prudence review of PSO's 2001 fuel and purchased power practices. If the OCC denies recovery of any portion of the $42 million under-recovery of reallocated costs, future results of operations and cash flows would be adversely affected.

In the review of PSO's 2001 fuel and purchased power practices, parties alleged that the allocation of off-system sales margins between AEP East and AEP West companies was inconsistent with the FERC-approved Operating Agreement and SIA and that the AEP West companies should have been allocated greater margins. The parties objected to the inclusion of mark-to-market amounts in developing the allocation base.

The OCC expanded the scope of the proceeding to include the off-system sales margin issue for the year 2002 and an intervenor filed a motion to expand the scope to review this same issue for the years 2003 and 2004. On July 25, 2005, the OCC Staff and two intervenors filed testimony in which they quantified the alleged improperly allocated off-system sales margins between AEP East and AEP West companies. Their overall recommendations would result in an increase in off-system sales margins allocated to PSO and thus, a reduction in its recoverable fuel costs through June 2005 of an amount between $38 million and $47 million. PSO does not agree with the intervenors' and the OCC Staff's recommendations and will defend vigorously its position. Accordingly, PSO has not recorded a provision for the off-system sales margins issue. Furthermore, should the OCC Staff prevail on this issue, we also believe the reallocation of off-system sales margins to PSO would be substantially less than their recommended amounts. On August 22, 2005, the Attorney General of Oklahoma filed a motion to suspend the procedural schedule, giving the parties sufficient time to review revised data.

As noted in the 2004 Annual Report, an Oklahoma ALJ found that the OCC lacks authority to examine whether PSO deviated from the FERC-approved allocation methodology and held that any such complaints should be addressed at the FERC. On September 29, 2005, the United States District Court, Western District of Texas, issued an order in the TNC fuel proceeding, preempting the PUCT from deciding this same allocation issue in Texas. The Court agreed with us that the FERC had jurisdiction over the SIA and that the sole remedy is at the FERC. It is unknown how the OCC will handle the jurisdictional issue. If the OCC continues to move forward on this issue, it could result in increased off-system sales margins included in the fuel clause adversely affecting future results of operations and cash flows for AEP and PSO. However, based on the position taken by the Federal court in Texas, it would appear that the OCC would be preempted from disallowing fuel recoveries for alleged improper allocations of system sales margins. If the OCC or another party files a complaint at the FERC and is successful, it could result in an adverse effect on results of operations and cash flows for the AEP East companies due to a reallocation of off-system sales margins between AEP East and AEP West companies.

In April 2005, the OCC heard arguments from intervenors that requested the OCC conduct a prudence review of PSO's fuel and purchased power practices for 2003. On June 10, 2005, the OCC decided to have its staff conduct that review. Management is unable to predict the ultimate effect of these Oklahoma fuel clause proceedings on revenues, results of operations, cash flows and financial condition.

PSO Lawton Power Supply Agreement

On November 26, 2003, pursuant to an application by Lawton Cogeneration Incorporated seeking approval of a Power Supply Agreement (the Agreement) with PSO and associated avoided cost payments, the OCC issued an order approving the Agreement and setting the avoided costs. The order did not approve recovery by PSO of the resultant purchased power costs.

In December 2003, PSO filed an appeal of the OCC's order with the Oklahoma Supreme Court. In the appeal, PSO maintained that the OCC exceeded its authority under state and federal laws to require PSO to enter into the Agreement. The Oklahoma Supreme Court issued a decision on June 21, 2005 affirming portions of the OCC's order and remanding certain provisions. The Court affirmed the OCC's finding that Lawton established a legally enforceable obligation and ruled that it was within the OCC's discretion to award a 20-year contract and to base the capacity payment on a peaking unit. The Court directed the OCC to revisit its determination of PSO's avoided energy cost. The OCC has appointed a settlement judge and negotiations are ongoing. A procedural schedule was issued September 30, 2005, which provides for a January 2006 hearing date. We are unable to predict the final outcome of the remand. However, if the OCC were to ultimately deny recovery of any portion of the cost of the resultant Agreement, it would adversely affect future results of operations and cash flows.

Upon resolution of the litigation, management will review any resultant transaction to determine if it can be accounted for as a purchased power transaction or whether it will be accounted for as a lease or as a generating plant asset on the balance sheet under FASB Interpretation No. 46 (revised December 2003), "Consolidation of Variable Interest Entities."

PSO Rate Review

PSO has been involved in a commission staff-initiated base rate review before the OCC which began in 2003. In that proceeding, PSO made a filing seeking to increase its base rates by $41 million, while various other parties made recommendations to reduce PSO's base rates. The annual rate reduction recommendations ranged between $15 million and $36 million. In March 2005, a settlement was negotiated and approved by the ALJ. The settlement provides for a $7 million annual base revenue reduction offset by a $6 million reduction in annual depreciation expense and recovery through fuel revenues of certain transmission expenses previously recovered in base rates. In addition, the settlement eliminates a $9 million annual merger savings rate reduction rider at the end of December 2005. The settlement also provides for recovery, over 24 months, of $9 million of deferred fuel costs associated with a renegotiated coal transportation contract and the continuation of a $12 million vegetation management rider, both of which are earnings neutral. Finally, the settlement stipulates that PSO may not file for a base rate increase before April 1, 2006. The OCC issued an order approving the stipulation on May 2, 2005 and new base rates were implemented in June 2005.

SWEPCo and TNC PUCT Staff Review of Earnings

On October 28, 2005, the staff of the PUCT reported results of its review of SWEPCo's and TNC's year-end 2004 earnings. Based upon the staff's adjustments to the information submitted by SWEPCo, the report indicates that SWEPCo is receiving excess revenues of approximately $15 million. The staff plans to engage SWEPCo in discussions to reconcile the earnings calculation and consider possible ways to address the results. Management is unable to predict the future outcome of this initial report on future revenues, results of operations, cash flows and financial condition. Staff recommended no further action regarding TNC at this time.

SWEPCo Texas Fuel Factor Filing

On November 7, 2005, due mainly to the increased cost of natural gas, SWEPCo filed a petition with the PUCT to increase its annual fixed fuel factor by $49 million and to surcharge $46 million of past under-recoveries over 12 months. Management cannot predict the ultimate outcome of this filing. Actual costs will be subject to review and approval in a future fuel reconciliation.

TCC Rate Case

On August 15, 2005, the PUCT issued an order in an ongoing base rate proceeding, reducing TCC's annual base rates by $9 million. This reduction in TCC's annual base rates will be offset by the elimination of a merger-related rate rider credit of $7 million, an increase in other miscellaneous revenues of $4 million and a decrease in depreciation expense of $9 million, resulting in a prospective increase in estimated annual pretax earnings of $11 million. Tariffs were approved and the rate change was implemented effective September 6, 2005. On October 6, 2005 the PUCT voted not to consider motions for rehearing. As a result, the August 15, 2005 order will become final and subject to appeal in mid-November. TCC is considering whether it will appeal this order. Also, in the third quarter of 2005, TCC reclassified $126 million from Accumulated Depreciation and Amortization to Regulatory Liability-Asset Removal Costs based on a depreciation study prepared by TCC and approved by the PUCT.

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

Several parties including the Office of Public Utility Counsel and cities served by both TCC and TNC appealed the PUCT's December 2001 orders establishing initial PTB fuel factors for Mutual Energy CPL and Mutual Energy WTU (TCC's and TNC's former affiliated REPs, respectively). In June 2003, the District Court ruled that the PUCT lacked sufficient evidence to include unaccounted for energy in the fuel factor for Mutual Energy WTU, that the PUCT improperly shifted the burden of proof from the company to intervening parties and that the record lacked substantial evidence on the effect of loss of load due to retail competition on generation requirements of both Mutual Energy WTU and Mutual Energy CPL. The Court upheld the initial PTB orders on all other issues. In an opinion issued on July 28, 2005, the Texas Court of Appeals reversed the District Court on the loss of load issue, but otherwise affirmed its decision. The amount of unaccounted for energy built into the PTB fuel factors attributable to Mutual Energy WTU prior to AEP's sale of Mutual Energy WTU was approximately $3 million. Our third quarter 2005 pretax earnings were adversely affected by $3 million because of this decision. TNC has filed a motion for rehearing regarding the unaccounted for energy issue at the Court of Appeals.

Texas Unbundled Cost of Service (UCOS) Appeal

The UCOS proceeding established the unbundled regulated wires rates to be effective when retail electric competition began in Texas. TCC placed new T&D rates into effect as of January 1, 2002 based upon an order issued by the PUCT resulting from TCC's UCOS proceeding. Certain PUCT rulings in this proceeding, including the initial determination of stranded costs, the requirement to refund TCC's excess earnings, the regulatory treatment of nuclear insurance and the distribution rates charged municipal customers, were appealed to the Travis County District Court by TCC and other parties to the proceeding. The District Court issued a decision on June 16, 2003, upholding the PUCT's UCOS order with one exception. The District Court ruled that the excess earnings refund methodology is unlawful because refunding the 1999 through 2001 excess earnings, solely as a credit to nonbypassable T&D rates charged to REPs, and not to the actual consumers of the electricity discriminates against residential and small commercial customers. TCC, TNC and other parties appealed this District Court ruling to the

Court of Appeals. In a decision issued on September 23, 2005, the Court of Appeals determined that the refund of excess earnings other than through the true-up process was unlawful under the Texas Restructuring Legislation, thereby reversing the determination of the PUCT and the District Court. This decision, in effect, reversed the District Court's determination that the refund methodology discriminated against certain customer classes. In all other respects, the decision of the District Court was affirmed. At this time, we are unable to predict if this decision will be appealed to the Texas Supreme Court.

TCC's position is that, consistent with the Court of Appeals determination, ordering separate early refunds of excess earnings was unlawful because the statute only permits such refunds to be accomplished as a part of the stranded cost determination in the True-up Proceeding. Nonetheless, TCC's true-up filing was based on a prior PUCT determination that assumed the legality of separate refunds of excess earnings. Therefore, if the Court of Appeals decision were to be implemented by permitting TCC to add a surcharge to its rates to recover previously refunded excess earnings, and stranded cost recovery was also adjusted, TCC's recovery could be affected in a largely offsetting manner in the two cases. Accordingly, in the third quarter of 2005, based on the probable outcome that the PUCT would implement the surcharge in the future, TCC reduced the amount of its recoverable stranded cost and recorded a separate regulatory asset for $49 million of excess earnings that should be refunded to TCC by the REPs. This resulted in a $9 million reduction to the true-up carrying cost regulatory asset, the effect of which was offset by an increase of $7 million in regulatory assets for the refund of the interest that had been previously refunded to the REPs. TCC cannot predict the ultimate outcome of this litigation; however, TCC believes the Court of Appeals decision significantly contributes to its position that customers are entitled to receive credit for excess earnings and related carrying cost effect on that amount as a reduction to stranded costs and not through an earlier refund in T&D rates.

At December 31, 2004, TCC had approximately $10 million of unrefunded excess earnings. During the first nine months of 2005, TCC refunded $9 million reducing its unrefunded excess earnings to $1 million. On July 15, 2005, the PUCT approved a preliminary order in the TCC True-up Proceeding that ordered TCC to cease refunding excess earnings at the end of July 2005. Under that order, the unrefunded balance of excess earnings of $1 million as of the end of July 2005 would reduce the balance of stranded costs.

Hold Harmless Proceeding

In a July 2002 order conditionally accepting our choice to join PJM, the FERC directed AEP, ComEd, Midwest Independent System Operator (MISO) and PJM to propose a solution that would effectively hold harmless the utilities in Michigan and Wisconsin from any adverse effects associated with loop flows or congestion resulting from us and ComEd joining PJM instead of MISO.

In July 2004, AEP and PJM filed jointly with the FERC a hold-harmless proposal. In September 2004, the FERC accepted and suspended the new proposal that became effective October 1, 2004, subject to refund and to the outcome of a hearing on the appropriate compensation, if any, to the Michigan and Wisconsin utilities. AEP and ComEd presented studies that showed no adverse effects to the Michigan and Wisconsin utilities. On December 27, 2004, AEP and the Wisconsin utilities jointly filed a settlement that resolves all hold-harmless issues for a one-time payment of $250 thousand that was approved by the FERC on March 7, 2005. On April 25, 2005, AEP and International Transmission Company in Michigan filed a settlement that resolves all hold-harmless issues for a one-time payment of $120 thousand that was approved by the FERC on June 24, 2005. On May 19, 2005, AEP and all remaining Michigan companies filed a settlement that resolves all hold-harmless issues for a one-time payment of approximately $2 million, which was approved by the FERC on June 24, 2005.

The payment to the Michigan utilities will be deferred, as was the Wisconsin payment, as a PJM integration cost to be amortized over 15 years and recovery will be sought in future retail rate filings. Management believes that it is probable that these payments will ultimately be recovered from retail and wholesale customers. If the AEP East companies cannot recover these amortizations on a timely basis in their retail base rates, future results of operations and cash flows will be adversely affected.

FERC Order on Regional Through and Out Rates

A load-based transitional transmission rate mechanism called SECA became effective December 1, 2004 to mitigate the loss of revenues due to the FERC's elimination of through and out (T&O) transmission rates. SECA transition rates are in effect through March 31, 2006. Intervenors in the SECA proceeding are objecting to the SECA rates and our method of determining those rates. The FERC has set SECA rate issues for hearing and indicated that the SECA rates are being recovered subject to refund. We recognized net SECA revenues of $36 million and $93 million in the third quarter and first nine months of 2005, respectively. In addition, we recognized $11 million of net SECA revenues in December 2004. Intervenors in the SECA proceeding are objecting to the SECA rates and our method of determining those rates. Management is unable to determine the probable outcome of the FERC's SECA rate proceeding.

In a March 31, 2005 FERC filing, we proposed an increase in the revenue requirements and rates for transmission service, and certain ancillary services in the AEP zone of PJM. The customers receiving these services are the AEP East companies, municipal and cooperative wholesale entities and retail customers that exercise retail choice that have load delivery points in the AEP zone of PJM. As proposed, the transmission service rates would increase in two steps, first to reflect an increase in the revenue requirements, and then to reflect the loss of revenues from the discontinuance of SECA transition rates on April 1, 2006. On May 31, 2005, the FERC accepted the filing, set the issues for hearing, and suspended the effective date of the first increase in the OATT rate until November 1, 2005, subject to refund with interest if lower rates are eventually approved. The FERC accepted the two-step increase concept, such that the transmission rates will automatically increase on April 1, 2006, if the SECA revenues cease to be collected, and to the extent that replacement rates are not established. In a separate proceeding, at AEP's urging, the FERC instituted an investigation of PJM's zonal rate regime, indicating that the present regime may need to be replaced through establishment of regional rates that would compensate AEP, among others, for the regional service provided by high voltage facilities they own that benefit customers throughout PJM. On September 30, 2005, AEP and a nonaffiliated utility (Allegheny Power) jointly filed a regional transmission rate design proposal with the FERC. This filing proposes and supports a new PJM rate regime.

As of September 30, 2005, SECA transition rates have not fully compensated the AEP East companies for their lost T&O revenues. Management is unable to predict whether SECA rates and, effective with the expiration of the SECA transition rates on March 31, 2006, the resultant increase in the AEP East zonal transmission rates applicable to AEP's internal load and wholesale transmission customers in AEP's zone will be sufficient to replace the SECA transition rate revenues. In addition, we are unable to predict whether the effect of the loss of transmission revenues will be recoverable on a timely basis in the AEP East state retail jurisdictions and from wholesale customers within the AEP zone. If, (i) the SECA transition rates do not fully compensate AEP for its lost T&O revenues through March 31, 2006, or (ii) AEP zonal transmission rates are not sufficiently increased by the FERC after March 31, 2006 to replace the lost T&O/SECA revenues, or (iii) the FERC's review of our current SECA rate results in a rate reduction which is subject to refund, or (iv) any increase in the AEP East companies' transmission costs from the loss of transmission revenues are not fully recovered in retail and wholesale rates on a timely basis, or (v) if the FERC does not approve a new rate within PJM, future results of operations, cash flows and financial condition would be adversely affected.

RTO Formation/Integration Costs

Prior to joining PJM, the AEP East companies, with FERC approval, deferred costs incurred to originally form a new RTO (the Alliance) and subsequently to integrate into an existing RTO (PJM) plus carrying costs. In 2004, AEP requested permission to amortize, beginning January 1, 2005, approximately $18 million of deferred RTO formation/integration costs not billed by PJM over 15 years and $17 million of deferred PJM-billed integration costs without proposing an amortization period for the $17 million of PJM-billed integration costs in the application. The FERC approved our application and in January 2005, the AEP East companies began amortizing their deferred RTO formation/integration costs not billed by PJM over 15 years and the deferred PJM-billed integration costs over 10 years consistent with a March 8, 2005 requested rate recovery period discussed below. The total amortization related to such costs was $1 million and $3 million in the third quarter and first nine months of 2005, respectively. As of September 30, 2005, the AEP East Companies have $34 million of deferred unamortized RTO formation/integration costs.

On March 8, 2005, AEP and two other utilities jointly filed a request with the FERC to recover their deferred PJM-billed integration costs from all load-serving entities in the PJM RTO over a ten-year period starting January 1, 2005. On May 6, 2005, the FERC issued an order denying the request to recover the amortization of the deferred PJM-billed integration costs from all load-serving entities in the PJM RTO, and instead, ordered the companies to make a Compliance Filing to recover the PJM-billed integration costs solely from the zones of the requesting companies. AEP, together with the other companies, made the Compliance Filing on May 27, 2005. On June 6, 2005, AEP filed a request for rehearing. Subsequently, the FERC approved the compliance rate, and PJM began charging the rate to load serving entities in the AEP zone (and the other companies' zones), including the AEP East companies on behalf of the load they serve in the AEP zone (about 85% of the total load in the AEP zone). On October 17, 2005, the FERC granted our June 6, 2005 rehearing request and set the following two issues for hearing and settlement discussions and, if necessary, for hearing: (1) whether the PJM OATT is unjust and unreasonable without region-wide recovery of PJM-billed integration costs and (2) a determination of a just and reasonable carrying charge rate on the deferred PJM-billed integration costs. Also, the FERC, in its order, dismissed the May 27, 2005 Compliance Filing as moot. At this time, management is unable to predict the outcome of this proceeding.

On March 31, 2005, we also filed a request for a revised transmission service revenue requirement for the AEP zone of PJM (as discussed above in the "FERC Order on Regional Through and Out Rates" section). Included in the costs reflected in that revenue requirement was the estimated 2005 amortization of our deferred RTO formation/integration costs (other than the deferred PJM-billed integration costs). The AEP East companies will be responsible for paying most of the amortized costs assigned by the FERC to the AEP East zone since their internal load is the bulk (about 85%) of the transmission load in the AEP zone. In Ohio, Kentucky and West Virginia, we have made filings to recover the amortization of these costs. I&M is currently subject to a rate freeze.

Until the AEP East Companies can adjust their retail rates to recover the amortization of both RTO deferred costs, results of operations and cash flows will be adversely affected by the amortizations. If the FERC allows AEP to charge the amortization of PJM-billed integration costs throughout the PJM region, it would mitigate any adverse effect from failure to obtain timely recovery in retail rates. If the FERC were to deny the inclusion in the transmission rates of any portion of the amortization of the deferred RTO formation/integration costs it would have an adverse impact on future results of operations and cash flows. If the FERC approves a carrying charge rate that is lower than the carrying charge recognized to date, it could have an adverse effect on future results of operations and cash flows.

Allocation Agreement between AEP East and AEP West companies

The SIA provides, among other things, for the methodology of sharing trading and marketing margins between the AEP East and AEP West companies. The current allocation methodology was established at the time of the AEP-CSW merger and, consistent with the terms of the SIA, on November 1, 2005, we filed a proposed allocation methodology to be used in 2006 and beyond. The proposed allocation methodology is based upon the location of the specific trading and marketing activity, with margins resulting from trading and marketing activities originating in PJM and MISO accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT accruing to the benefit of the AEP West companies. Previously, the SIA allocation provided for sharing of all such margins among both AEP East and AEP West companies. The allocation ultimately approved by the FERC may differ from the one we proposed. We requested that the new methodology be effective on a prospective basis after the FERC's order. The impact on future results of operations and cash flows will depend upon the methodology approved by the FERC and the level of future margins by region. Our total trading and marketing margins are unaffected by the allocation methodology. However, because trading and marketing activities are not treated the same for rate-making purposes in each state retail jurisdiction and the timing of inclusion of the margins in rates may differ, our results of operations and cash flow could be affected. Management is unable to predict the ultimate effect of this filing on our future results of operations and cash flows.

4. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING

We are affected by customer choice initiatives and industry restructuring. The Customer Choice and Industry Restructuring note in our 2004 Annual Report should be read in conjunction with this report in order to gain a complete understanding of material customer choice and industry restructuring matters without significant changes since year-end. The following paragraphs discuss significant current events related to customer choice and industry restructuring and update the 2004 Annual Report.

OHIO RESTRUCTURING

On January 26, 2005, the PUCO approved Rate Stabilization Plans (RSP) for CSPCo and OPCo (the Ohio companies). The plans provided, among other things, for CSPCo and OPCo to raise their generation rates by 3% and 7%, respectively, in 2006, 2007 and 2008 and provided for possible additional annual generation rate increases of up to an average of 4% per year based on supporting the need for additional revenues for specified costs. The plans also provided that the Ohio companies could recover in 2006, 2007 and 2008 environmental carrying costs and PJM-related administrative costs and congestion costs net of firm transmission rights (FTR) revenue from 2004 and 2005 related to their obligation as the Provider of Last Resort (POLR) in Ohio's customer choice program. Pretax earnings increased by $6 million for CSPCo and $35 million for OPCo in the first nine months of 2005 as a result of implementing this provision of the RSP. Of these amounts, approximately $8 million for CSPCo and $21 million for OPCo relate to 2004 environmental carrying costs and RTO costs. The decline in the third quarter of 2005 reflects the effect of substantial increases in FTR revenues which offset administrative and congestion costs.

In February 2005, various intervenors filed applications for rehearing with the PUCO regarding its approval of the RSP. On March 23, 2005, the PUCO denied all applications for rehearing. In the second quarter of 2005, two intervenors filed separate appeals to the Ohio Supreme Court. One of those appeals has been withdrawn. The remaining appeal challenges the RSP and also argues that there is no POLR obligation in Ohio, and therefore CSPCo and OPCo are not entitled to recover any POLR charges. If the Ohio Supreme Court reverses the PUCO's authorization of the POLR charge, CSPCo and OPCo's 2005 earnings will be adversely affected. In a nonaffiliated utility's proceeding, the Ohio Supreme Court concluded that there is a POLR obligation in Ohio, and therefore, CSPCo and OPCo have argued that they can recover the POLR charge. In addition, if the RSP order is determined on appeal to be illegal under the restructuring legislation, it would have an adverse effect on results of operations, cash flows and possibly financial condition. Although we believe that the RSP plan is legal and we intend to defend vigorously the PUCO's order, we cannot predict the ultimate outcome of the pending litigation.

On September 28, 2005, the Ohio companies filed with the PUCO to recover through a Transmission Cost Recovery Rider, beginning January 1, 2006, approximately $5 million for CSPCo and $7 million for OPCo of projected 2006 net costs incurred as a result of joining PJM. In addition, the Ohio companies requested to practice over/under-recovery deferral accounting for any differences between the revenues collected starting January 1, 2006 and the actual costs incurred. If the PUCO determines that any of the requested net incremental RTO costs are unrecoverable, it would have an adverse impact on future results of operations and cash flows.

As provided in stipulation agreements approved by the PUCO in 2000, we are deferring customer choice implementation costs and related carrying costs in excess of $40 million. The agreements provide for the deferral of these costs as a regulatory asset until the next distribution base rate cases. Through September 30, 2005, we incurred $86 million of such costs, and accordingly, we deferred $46 million of such costs for probable future recovery in distribution rates. Recovery of these regulatory assets will be subject to PUCO review in future Ohio filings for new distribution rates. Pursuant to the RSP, recovery of these amounts will be deferred until the next distribution rate filing to change rates after December 31, 2008. We believe that the deferred customer choice implementation costs were prudently incurred to implement and effect customer choice in Ohio and should be recoverable in future distribution rates. If the PUCO determines that any of the deferred costs are unrecoverable, it would have an adverse impact on future results of operations and cash flows.

TEXAS RESTRUCTURING

The stranded cost recovery process in Texas continues with the principal remaining component of the process being the PUCT's determination and approval of TCC's net stranded generation costs and other recoverable true-up items including carrying costs in TCC's true-up filing under the Texas Restructuring Legislation. The PUCT approved TCC's request to file its True-up Proceeding after the sales of its interest in STP, with only the ownership interest in Oklaunion remaining to be settled. On May 19, 2005, the sales of TCC's interest in STP closed. On May 27, 2005, TCC filed its true-up request seeking recovery of $2.4 billion of net stranded costs and other true-up items which it believes the Texas Restructuring Legislation allows, including unrecorded equity carrying costs, which are not recognizable until collected, and unrecorded carrying costs on amounts previously provided for totaling approximately $440 million. The filing does not include a deduction for a $238 million provision for a probable depreciation adjustment recorded in December 2004 based on a methodology approved by the PUCT in a nonaffiliated utility's true-up order. Although it was determined that it was probable that the PUCT would make this adjustment in TCC's proceeding and the adjustment was provided for, we do not believe the adjustment is appropriate and will litigate the issue, if necessary. As a result, the filing was not reduced by the $238 million provision for probable loss. These items account for the majority of the difference between the $2.4 billion filing and the $1.6 billion net regulatory asset detailed below. As discussed below, the PUCT Staff and various intervenors filed testimony recommending that TCC's $2.4 billion requested recovery amount be reduced, with certain parties asserting that TCC does not have any stranded costs. The PUCT hearing began on September 26, 2005 and concluded on October 4, 2005. It is anticipated that the PUCT will issue a final order in the fourth quarter of 2005.

The Components of TCC's Recorded Net True-up Regulatory Asset (inclusive of provisions) recorded as of September 30, 2005 and December 31, 2004 are:

	TCC	
	September 30, 2005	**December 31, 2004**
	(in millions)	
Stranded Generation Plant Costs	$ 892	$ 897
Net Generation-related Regulatory Asset	249	249
Excess Earnings	(49)	(10)
Net Stranded Generation Costs	1,092	1,136
Carrying Costs on Stranded Generation Plant Costs	218	225
Net Stranded Generation Costs Designated for Securitization	1,310	1,361
Wholesale Capacity Auction True-up	483	483
Carrying Costs on Wholesale Capacity Auction True-up	114	77
Retail Clawback	(61)	(61)
Deferred Over-recovered Fuel Balance	(210)	(212)

Net Other Recoverable True-up Amounts		326		287
Total Recorded Net True-up Regulatory Asset	$	1,636	$	1,648

The Components of TNC's Net True-up Regulatory Liability as of September 30, 2005 and December 31, 2004 are:

	TNC			
	September 30, 2005		**December 31, 2004**	
	(in millions)			
Retail Clawback	$	(14)	$	(14)
Deferred Over-recovered Fuel Balance		(5)		(4)
Total Recorded Net True-up Regulatory Liability	$	(19)	$	(18)

Deferred Investment Tax Credits Included in Stranded Generation Plant Costs

In a nonaffiliated utility's securitization proceeding, the PUCT issued an order in March 2005 that net stranded generation costs should be reduced by the present value of deferred investment tax credits (ITC) and excess deferred federal income taxes applicable to generating assets. The nonaffiliated utility testified in its True-up Proceeding that acceleration of the sharing of deferred ITC with customers may be a violation of the Internal Revenue Code's normalization provisions. Management agrees with the nonaffiliated utility that the PUCT's acceleration of deferred ITC and excess deferred federal income taxes may be a violation of the normalization provisions. As a result, management has not included as a reduction of its net stranded generation costs the present value of TCC's generation-related deferred ITC of $70 million and the present value of excess deferred federal income taxes of $6 million in its true-up filing. Although deferred ITC and excess deferred federal income taxes are recorded as a liability on TCC's books, such amounts also are not reflected as a reduction of TCC's recorded net stranded generation costs regulatory asset in the above table since to do so may be a normalization violation. The Internal Revenue Service (IRS) has issued proposed regulations that would make an exception to the normalization provisions for a utility whose electric generation assets cease to be public utility property. Since the IRS has not issued final regulations, TCC filed a request for a private letter ruling from the IRS on June 28, 2005 to determine whether the PUCT's action would result in a normalization violation. A normalization violation could result in the repayment of TCC's accumulated deferred ITC on all property, not just generation property, which approximates $106 million as of September 30, 2005 and a loss of the ability to elect accelerated tax depreciation in the future. Various parties in TCC's True-up Proceeding have recommended that the present value of the ITCs and the nominal value of excess deferred federal income taxes applicable to generating assets be utilized to reduce TCC's requested stranded cost amount. Management is unable to predict how the IRS will rule on the private letter ruling request and whether any PUCT order will adversely affect future results of operations and cash flows.

TCC Fuel Reconciliation

On April 14, 2005, the PUCT ruled that specific energy-only purchased power contracts included a capacity component, which is not recoverable in fuel rates. As a result of this decision, in the first quarter of 2005, TCC recorded a provision for over-recovered fuel of $3 million, inclusive of interest. Reflecting all of the decisions in the final order and the resultant provisions for refund, the deferred over-recovery balance was $210 million as of September 30, 2005, including accrued interest. TCC filed a motion for rehearing on several items which was denied by operation of law on July 18, 2005. TCC appealed the PUCT's decision to state and federal courts in August 2005. As discussed in the "TNC True-up Proceeding" section below, TNC received a decision from the Federal District Court that the PUCT is preempted by federal law from revising the allocation of system sales margins under the FERC-approved SIA by removing mark-to-market amounts from the East/West allocation base. The same issue was presented in TCC's final fuel reconciliation proceeding for which TCC has also filed an appeal to the Federal District Court. As with TNC, it is expected that the PUCT will also be preempted by the Federal District Court from reallocating the off-system sales margins under the FERC-approved SIA for TCC. Therefore, the PUCT would have to file a complaint with the FERC to address the TCC allocation issue. We are unable to determine whether the PUCT will appeal the Federal District Court decision or file a complaint with the FERC, and if it does either, whether such appeal or complaint would probably be successful. Pending further clarification, TCC has not yet reversed the $46 million provision for fuel cost over-recovery recorded in 2004. If the PUCT or another party files a complaint at the FERC and is successful, it could result in an adverse effect on results of operations and cash flows for the AEP East companies due to a reallocation of off-system sales margins between AEP East and AEP West companies.

TCC Carrying Costs on Net True-up Regulatory Assets

TCC continues to accrue carrying costs on its net true-up regulatory asset at the embedded 8.12% debt component rate and will continue to do so until it recovers its approved net true-up regulatory asset. In a nonaffiliated utility's securitization proceeding, the PUCT issued an order in March 2005 that resulted in a reduction in its carrying costs based on a methodology detailed in the order for calculating a cost-of-money benefit related to accumulated deferred federal income taxes (ADFIT) on net stranded costs and other true-up items which was retroactively applied to January 1, 2004. In the first nine months of 2005, TCC accrued carrying costs of $57 million which were partially offset by a first quarter adjustment of $27 million based on this order. The net increase of $30 million in carrying costs is included in Other Income on the accompanying Condensed Consolidated Statements of Income in the first nine months of 2005 inclusive of $15 million of carrying costs accrued in the third quarter of 2005.

In an April 2005 open meeting regarding another nonaffiliated utility's True-up Proceeding, the PUCT determined that the filed cost of debt did not establish a Weighted Average Cost of Capital (WACC) rate or an embedded debt rate because that utility's Unbundled Cost of Service (UCOS) case was based on a settlement that did not specifically address the debt rate. As a result, the other utility was required to use a subsequently approved lower debt rate to compute its carrying costs than its filed UCOS rate.

To date, this nonaffiliated utility's issue has not been raised in TCC's True-up Proceeding. Alternatively, parties have recommended in TCC's True-up Proceeding that the PUCT reduce TCC's carrying cost rate to an amount that ranged from 7.5% to the combined rate that was settled upon in TCC's wires rate proceeding which included a cost of debt of 5.7%. Management is unable to determine the probable outcome of this matter when, or if, it is adjudicated in TCC's True-up Proceeding. If the

PUCT ultimately determines that a lower cost of debt should be used by TCC to calculate carrying costs on its stranded cost balance, it would have an adverse impact on future results of operations and cash flows. Based upon a range of debt rates from 5.7% to 7.5%, through the third quarter of 2005, such adverse effect ranges from $28 million to $107 million, of which $6 million to $22 million would apply to amounts accrued in 2005.

Through September 30, 2005, TCC has computed carrying costs of $509 million, of which $302 million was recognized as income in 2004 and applied to years prior to 2005. Approximately $57 million was recognized as income in the first nine months of 2005 before the $27 million offsetting adjustment discussed above. The remaining equity component of the carrying costs of $177 million through September 30, 2005 will be recognized in income as collected.

TCC Excess Earnings

At December 31, 2004, TCC had approximately $10 million of unrefunded excess earnings. In the first nine months of 2005, TCC refunded an additional $9 million reducing its unrefunded excess earnings to $1 million. On July 15, 2005, the PUCT approved a preliminary order in TCC's True-up Proceeding that instructed TCC to stop refunding the excess earnings and to offset the remaining balance, which was $1 million, against stranded costs. However, on September 23, 2005, the Texas Court of Appeals issued a decision finding the PUCT's prior order requiring us to refund excess earnings as determined in TCC's UCOS proceeding was unlawful under the Texas Restructuring Legislation. As such, TCC recorded a regulatory asset for the future recovery of the $49 million refunded to the REPs and a reduction to stranded costs. See the "Texas Unbundled Cost of Service (UCOS) Appeal" section of Note 3 for further details.

TCC True-up Proceeding

As discussed earlier, TCC made its true-up filing requesting $2.4 billion of stranded costs including the effect of the PUCT's July 15, 2005 order discontinuing the excess earnings refund as discussed in the "Texas Unbundled Cost of Service (UCOS) Appeal" section of Note 3. During September 2005, various parties and the PUCT staff filed testimony recommending reductions to TCC's requested stranded cost amount including a recommendation that TCC does not have any stranded costs. Hearings began September 26, 2005 and continued until October 4, 2005. An order is expected in the fourth quarter of 2005. When the True-up Proceeding is completed, TCC intends to file to recover the PUCT-approved net stranded generation costs and other true-up amounts, plus appropriate carrying costs, through a nonbypassable competition transition charge (CTC) in the regulated transmission and distribution (T&D) rates and through an additional transition charge for amounts that can be recovered through the sale of securitization bonds.

The nonaffiliated utility's March 2005 order referred to in the "TCC Carrying Costs on Net True-up Regulatory Assets" section above also provided for the present value of the cost free capital benefits of ADFIT associated with stranded generation costs to be offset against other recoverable true-up amounts when establishing the CTC. TCC estimates its present value ADFIT benefit to be $209 million based on its current net true-up regulatory asset. TCC performed a probability of recovery impairment test on its net true-up regulatory asset taking into account the treatment ordered by the PUCT in the nonaffiliated utility's order and determined that the projected cash flows from the transition charges were more than sufficient to recover TCC's recorded net true-up regulatory asset since the equity portion of the carrying costs will not be recorded until collected. As a result, no impairment has been recorded. Barring any future disallowances to TCC's net recoverable true-up regulatory asset in its True-up Proceeding, TCC expects to amortize its total net true-up regulatory asset commensurate with recovery over periods to be established by the PUCT in proceedings subsequent to TCC's True-up Proceeding.

We believe that our filed request for recovery of $2.4 billion of net stranded costs and other true-up items, inclusive of carrying costs, is recoverable under the Texas Restructuring Legislation. However, after recording certain provisions for probable disallowances from TCC's final fuel proceeding and nonaffiliated true-up proceedings and adjusting for unrecordable equity carrying costs and carrying costs on the provisions, TCC has a $1.6 billion recorded net true-up regulatory asset, inclusive of carrying costs, at September 30, 2005 that is probable of recovery at this time. However , other parties have contended that all or material amounts of our net stranded costs and/or wholesale capacity auction true-up amounts should not be recovered. To the extent decisions of the PUCT in TCC's True-up Proceeding differ from our interpretation and application of the Texas Restructuring Legislation and our evaluation of other true-up orders of nonaffiliated utilities, additional provisions for material disallowances and reductions of the net true-up regulatory asset, including recorded carrying costs, are possible. Such disallowances would have a material adverse effect on future results of operations, cash flows and possibly financial condition.

TNC True-Up Proceeding

In March 2005, the ALJ made certain recommendations regarding the deferred fuel balance resulting in an additional provision for refund of $1 million, which results in an over-recovery amount of $5 million. In May 2005, the PUCT issued a favorable order, adopting the ALJ's recommendation regarding the application of interest to the post-reconciliation period off-system sales margins, but did not adopt the ALJ's excess earnings recommendation. The PUCT required that excess earnings be addressed in the CTC filing that was made on August 5, 2005. Based upon the ruling regarding the application of interest on post-reconciliation off-system sales margins, TNC adjusted its deferred over-recovered fuel balance during the second quarter of 2005.

In 2004, TNC appealed to the state and federal courts the PUCT's order in its final fuel reconciliation covering the period from July 2000 through December 31, 2001 in which the PUCT disallowed approximately $30 million of fuel costs. On September 9, 2005, the Texas District Court in Travis County issued a ruling which upheld in all respects the PUCT's decisions concerning issues appealed to that court by all parties. TNC has filed notice of appeal of that decision. TNC will continue to pursue vigorously the state appeals, but cannot predict their outcome. TNC believes it has fully provided for the PUCT final fuel order.

On September 29, 2005, the Federal District Court, Western District of Texas, issued an order precluding the PUCT from enforcing their ruling regarding the allocation of off-system sales margins. The impact of the reallocation resulted in an over-recovery amount of $8 million. The PUCT must appeal the Federal Court decision or file a complaint at FERC, if it wishes to challenge this ruling. We are unable to predict whether the PUCT will appeal the Federal District Court decision and/or file a complaint at FERC, nor are we able to predict whether such actions would be successful. Pending further clarification, TNC has not yet reversed its related $8 million provision for fuel over-recovery. If the PUCT or another party files a complaint at the FERC and is successful, it could result in an adverse effect on results of operations and cash flows for the AEP East companies due to a reallocation of off-system sales margins between AEP East and AEP West companies.

5. COMMITMENTS AND CONTINGENCIES

As discussed in the Commitments and Contingencies note within our 2004 Annual Report, we continue to be involved in various legal matters. The 2004 Annual Report should be read in conjunction with this report in order to understand the other material nuclear and operational matters without significant changes since our disclosure in the 2004 Annual Report. The matters discussed in the 2004 Annual Report without significant changes in status since year-end include, but are not limited to, (1) nuclear matters, (2) construction and commitments, (3) potential uninsured losses, (4) shareholder lawsuits, (5) coal transportation dispute, and (6) FERC long-term contracts. See disclosure below for significant matters with changes in status subsequent to the disclosure made in our 2004 Annual Report.

Environmental

Federal EPA Complaint and Notice of Violation

The Federal EPA and a number of states have alleged APCo, CSPCo, I&M, OPCo and other nonaffiliated utilities modified certain units at coal-fired generating plants in violation of the new source review requirements of the CAA. The Federal EPA filed its complaints against our subsidiaries in U.S. District Court for the Southern District of Ohio. The court also consolidated a separate lawsuit, initiated by certain special interest groups, with the Federal EPA case. The alleged modifications occurred at our generating units over a 20-year period. A bench trial on the liability issues was held during July 2005. Briefing has concluded.

Under the CAA, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant. The CAA authorizes civil penalties of up to $27,500 per day per violation at each generating unit ($25,000 per day prior to January 30, 1997). In 2001, the District Court ruled claims for civil penalties based on activities that occurred more than five years before the filing date of the complaints cannot be imposed. There is no time limit on claims for injunctive relief.

In June 2004, the Federal EPA issued a Notice of Violation (NOV) in order to "perfect" its complaint in the pending litigation. The NOV expands the number of alleged "modifications" undertaken at the Amos, Cardinal, Conesville, Kammer, Muskingum River, Sporn and Tanners Creek plants during scheduled outages on these units from 1979 through the present. Approximately one-third of the allegations in the NOV were already contained in allegations made by the states or the special interest groups in the pending litigation. The Federal EPA filed a motion to amend its complaint and to expand the scope of the pending litigation. The AEP subsidiaries opposed that motion. In September 2004, the judge disallowed the addition of claims to the pending case. The judge also granted motions to dismiss a number of allegations in the original filing. Subsequently, the Federal EPA and eight Northeastern states each filed an additional complaint containing the same allegations against the Amos and Conesville plants that the judge disallowed in the pending case. The Northeastern states' complaint has been assigned to the same judge in the U.S. District Court for the Southern District of Ohio. AEP filed an answer to the Northeastern states' complaint and to the Federal EPA's complaint, denying the allegations and stating its defenses.

In August 2003, the District Court issued a decision following a liability trial in a case pending in the Southern District of Ohio against Ohio Edison Company, a nonaffiliated utility. The District Court held that replacements of major boiler and turbine components that are infrequently performed at a single unit, that are performed with the assistance of outside contractors, that are accounted for as capital expenditures, and that require the unit to be taken out of service for a number of months are not "routine" maintenance, repair and replacement. The District Court also held that a comparison of past actual emissions to projected future emissions must be performed prior to any nonroutine physical change in order to evaluate whether an emissions increase will occur, and that increased hours of operation that are the result of eliminating forced outages due to the repairs must be included in that calculation. Based on these holdings, the District Court ruled that all of the challenged activities in that case were not routine, and that the changes resulted in significant net increases in emissions for certain pollutants. A settlement between Ohio Edison, the Federal EPA and other parties to the litigation will avoid further litigation and result in expenditures at the plant.

Other utility enforcement actions and current regulatory activities are discussed in detail in the Commitments and Contingencies note in the 2004 Annual Report. However, since the issuance of the August 2003 decision against Ohio Edison, several other courts have considered the issues of what constitutes "routine maintenance, repair, and replacement" for utility units, and whether increased hours of operation are the measure of an emissions increase. Each court has reached a conclusion that differs markedly from the decision in the Ohio Edison case. These decisions include the District Court opinion in the Duke Energy case issued later in August 2003, the District Court opinion in Alabama Power case issued on June 3, 2005, and the Fourth Circuit Court of Appeals opinion affirming the dismissal of all claims against Duke Energy issued on June 15, 2005. In addition, on June 10, 2005, the Administrator of the Federal EPA rejected all of the petitions for reconsideration of the October 2003 "equipment replacement provision" rule that defines "routine replacement" under the new source review program to include the same types of activities challenged in the pending enforcement actions. Management therefore believes that the Ohio Edison decision fails to properly evaluate and apply the applicable legal standards. The facts in our case also vary widely from plant to plant.

In June 2003, the United States Court of Appeals for the District of Columbia Circuit granted a petition by the Utility Air Regulatory Group (UARG), of which our subsidiaries are members, to reopen petitions for review of the 1980 and 1992 Clean Air Act rulemakings that are the basis for the Federal EPA claims in our case and other related cases. On June 24, 2005, the United States Court of Appeals for the District of Columbia Circuit issued a decision affirming in part the new source review reform regulations adopted by the Federal EPA in December 2002. The court upheld the Federal EPA's decision to apply actual-to-future actual emissions and includes tests, utilizing a five-year look back period to establish actual baseline emissions for utilities and a ten-year period for other sources. This excludes increased emissions unrelated to a physical change from the projected emissions, and includes emissions associated with demand growth. The court vacated the Federal EPA's adoption of a broad pollution control project exclusion that includes projects that result in a significant collateral emissions increase, and the "clean unit" applicability test, and remanded certain recordkeeping requirements to the

Federal EPA. The court expressed no opinion on the conclusion reached by the Duke Energy court, and found that such issues could be better addressed in a specific factual context.

On August 30, 2005, the United States Court of Appeals for the Fourth Circuit denied the petitions for rehearing filed by the United States and other appellants in the Duke Energy case. On October 13, 2005, the Administrator of the Federal EPA signed a proposed rule that would adopt a test for determining when an emissions increase results from a change at an existing electric utility generating unit under the federal NSR programs that would be consistent with the test adopted and applied by the Fourth Circuit in the Duke Energy case. This would be based on maximum hourly emissions before and after the change. The Federal EPA is also seeking comments on two alternative formulations of the emission increase test. We have filed a Motion in the NSR litigation that asks the Court, among other things, to dismiss the NSR cases on due process grounds based on the statements and admissions the Federal EPA made in promulgating the proposed rule.

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

SWEPCo Notice of Enforcement and Notice of Citizen Suit

On July 13, 2004, two special interest groups issued a notice of intent to commence a citizen suit under the CAA for alleged violations of various permit conditions in permits issued to several SWEPCo generating plants. On March 10, 2005, a complaint was filed in Federal District Court for the Eastern District of Texas by the two special interest groups, alleging violations of the CAA at Welsh Plant. SWEPCo filed a response to the complaint in May 2005.

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

On August 13, 2004, TCEQ issued a Notice of Enforcement to SWEPCo relating to the off-specification fuel oil deliveries at the Knox Lee Plant. On April 11, 2005, TCEQ issued an Executive Director's Preliminary Report and Petition recommending the entry of an enforcement order and assessing an administrative penalty of approximately $6 thousand against SWEPCo based on alleged violations of certain permit requirements at Knox Lee. SWEPCo responded to the preliminary report and petition on May 2, 2005.

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

Carbon Dioxide Public Nuisance Claims

In July 2004, attorneys general from eight states and the corporation counsel for the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC and four other nonaffiliated governmental and investor-owned electric utility systems. That same day, a similar complaint was filed in the same court against the same defendants by the Natural Resources Defense Council on behalf of three special interest groups. The actions alleged that carbon dioxide emissions from power generation facilities constitute a public nuisance under federal common law due to impacts associated with global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. In September 2004, the defendants, including AEP and AEPSC, filed a motion to dismiss the lawsuits. In September 2005, the lawsuits were dismissed. A notice of appeal to the Second Circuit Court of Appeals has been filed on behalf of all plaintiffs. A briefing schedule has not been established.

Operational

Construction

The AEP System has substantial construction activity scheduled to support its operations. Aggregate construction expenditures for 2006 for consolidated operations are estimated at $3.3 billion, including amounts for proposed environmental rules. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends and the ability to access capital.

TEM Litigation (Power Generation Facility)

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

Dow uses a portion of the energy produced by the Facility and sells the excess energy. OPCo has agreed to purchase up to approximately 800 MW of such excess energy from Dow for a 20-year term. Because the Facility is a major steam supply for Dow, Dow is expected to operate the Facility at certain minimum levels, and OPCo is obligated to purchase the energy generated at those minimum operating levels (expected to be approximately 220 MW through May 31, 2006 and 270 MW thereafter). OPCo sells the purchased energy at market prices in the Entergy sub-region of the Southeastern Electric Reliability Council market.

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

In September 2003, TEM and AEP separately filed declaratory judgment actions in the United States District Court for the Southern District of New York. We alleged that TEM breached the PPA, and we sought a determination of our rights under the PPA. TEM alleged that the PPA never became enforceable, or alternatively, that the PPA was terminated as the result of AEP's breaches. The corporate parent of TEM (SUEZ-TRACTEBEL S.A.) has provided a limited guaranty.

On April 5, 2004, OPCo gave notice to TEM that OPCo, (i) was suspending performance of its obligations under the PPA, (ii) would be seeking a declaration from the New York federal court that the PPA was terminated and (iii) would be pursuing against TEM, and SUEZ-TRACTEBEL S.A. under the guaranty, damages and the full termination payment value of the PPA.

A bench trial was conducted in March and April 2005. In August 2005, a federal judge ruled that TEM had breached the contract and awarded us damages of $123 million plus pre-judgment interest. In August 2005, both parties filed motions with the trial court seeking reconsideration of the judgment. We asked the court to modify the judgment to (i) award a termination payment to us under the terms of the PPA; (ii) grant our attorneys' fees; and (iii) render judgment against SUEZ-TRACTEBEL, S.A. on the guaranty. TEM sought reduction of the damages awarded by the court for replacement electric power products made available by OPCo under the PPA.

In September 2005, TEM posted a letter of credit for $142 million as security pending appeal of the judgment. Both parties have filed Notices of Appeal with the United States Court of Appeals for the Second Circuit. If the PPA is deemed terminated or found to be unenforceable by the court ultimately deciding the case, we could be adversely affected to the extent we are unable to find other purchasers of the power with similar contractual terms and to the extent we do not fully recover claimed termination value damages from TEM.

Merger Litigation

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

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

We believe the repeal of PUHCA will end litigation challenging our merger with CSW. All parties to the proceeding have filed motions with the SEC supporting dismissal of the proceeding upon repeal of the PUHCA in February 2006.

Enron Bankruptcy

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

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

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

In October 2003, AEP filed a lawsuit against BOA in the United States District Court for the Southern District of Texas. BOA led a lending syndicate involving the 1997 gas monetization that Enron and its subsidiaries undertook and the leasing of the Bammel underground gas storage reservoir to HPL. The lawsuit asserts that BOA made misrepresentations and engaged in fraud to induce and promote the stock sale of HPL, that BOA directly benefited from the sale of HPL and that AEP undertook the stock purchase and entered into the Bammel storage facility lease arrangement with Enron and the cushion gas arrangement with Enron and BOA based on misrepresentations that BOA made about Enron's financial condition that BOA knew or should have known were false including that the 1997 gas monetization did not contravene or constitute a default of any federal, state, or local statute, rule, regulation, code or any law. In February 2004, BOA filed a motion to dismiss this Texas federal lawsuit. In September 2004, the Magistrate Judge issued a Recommended Decision and Order recommending that BOA's Motion to Dismiss be denied, that the five counts in the lawsuit seeking declaratory judgments involving the

Bammel reservoir and the right to use and cushion gas consent agreements be transferred to the Southern District of New York and that the four counts alleging breach of contract, fraud and negligent misrepresentation proceed in the Southern District of Texas. BOA objected to the Magistrate Judge's decision. On April 6, 2005, the Judge entered an order overruling BOA's objections, denying BOA's Motion to Dismiss and severing and transferring the declaratory judgment claims to the Southern District of New York.

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

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

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

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

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

Natural Gas Markets Lawsuits

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

Cornerstone Lawsuit

In the third quarter of 2003, Cornerstone Propane Partners filed an action in the United States District Court for the Southern District of New York against forty companies, including AEP and AEPES, seeking class certification and alleging unspecified damages from claimed price manipulation of natural gas futures and options on the NYMEX from January 2000 through December 2002. Thereafter, two similar actions were filed in the same court against a number of companies including AEP and AEPES making essentially the same claims as Cornerstone Propane Partners and also seeking class certification. In December 2003, the Court issued its initial Pretrial Order consolidating all related cases, appointing co-lead counsel and providing for the filing of an amended consolidated complaint. In January 2004, plaintiffs filed an amended consolidated complaint. The defendants filed a motion to dismiss the complaint which the Court denied in September 2004. Discovery is continuing in the case with a closing date of December 23, 2005. In October 2005, the court granted the plaintiffs motion for class certification. The defendants have filed a petition for leave to appeal this decision. Summary judgment motions are due in January 2006. We intend to continue to defend vigorously against these claims.

Texas Commercial Energy, LLP Lawsuit

Texas Commercial Energy, LLP (TCE), a Texas REP, filed a lawsuit in federal District Court in Corpus Christi, Texas, in July 2003, against us and four of our subsidiaries, ERCOT and a number of nonaffiliated energy companies including TXU, CenterPoint, Texas Genco, Reliant, TECO and Tractebel. The action alleges violations of the Sherman Antitrust Act, fraud, negligent misrepresentation, breach of fiduciary duty, breach of contract, civil conspiracy and negligence. The allegations, not all of which are made against the AEP companies, range from anticompetitive bidding to withholding power. TCE alleges that these activities resulted in price spikes requiring TCE to post additional collateral and ultimately forced it into bankruptcy when it was unable to raise prices to its customers due to their fixed price contracts. The suit alleges over $500 million in damages for all defendants and seeks recovery of damages, exemplary damages and court costs. In June 2004, the Court dismissed all claims against the AEP companies. TCE appealed the trial court's decision to the United States Court of Appeals for the Fifth Circuit. The Fifth Circuit issued its decision in June 2005 and affirmed the lower court's decision. TCE filed a Petition for Writ of Certiorari with the United States Supreme Court on October 14, 2005. In March 2005, Utility Choice, LLC and Cirro Energy Corporation filed in U.S. District Court alleging similar violations as those alleged in the TCE lawsuit against the same defendants and others. Trial is scheduled in the Utility Choice/Cirro Energy case for April 2006. On October 18, 2005, the U.S. District Court heard oral arguments on our Motion to Dismiss. We intend to continue to defend vigorously against the allegations in these cases.

Bank of Montreal Claim

In March 2003, Bank of Montreal (BOM) terminated all natural gas trading deals with us. In April 2003, we filed a lawsuit in federal District Court in Columbus, Ohio against BOM claiming BOM had acted contrary to the appropriate trading contract and industry practice in terminating the contract and calculating termination and liquidation amounts. We claimed that BOM owed us at least $41 million related to previously recorded receivables on which we held approximately $20 million of credit collateral. In September 2005, we reached a settlement, subject to a confidentiality clause, with BOM without material impact on results of operations or financial condition.

Ontario Litigation

In June 2005, we were named as one of 21 defendants in a lawsuit filed in the Superior Court of Justice in Ontario, Canada. We have not been served with the lawsuit. The defendants are alleged to own or operate coal-fired electric generating stations in various states that, through negligence in design, management, maintenance and operation, have emitted NO_x, SO_2 and particulate matter that have harmed the residents of Ontario. The lawsuit seeks class action designation and damages of approximately $50 billion, with continuing damages of $4 billion annually. The lawsuit also seeks $1 billion in punitive damages. We believe we have meritorious defenses to this action and intend to defend vigorously against it.

6. GUARANTEES

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

LETTERS OF CREDIT

We have entered into standby letters of credit (LOC) with third parties. These LOCs generally cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits, debt service reserves and credit enhancements for issued bonds. We issued all of these LOCs in our ordinary course of business. At September 30, 2005, the maximum future payments for all the LOCs were approximately $327 million with maturities ranging from November 2005 to April 2007. As the parent of the various subsidiaries that have issued these LOCs, we hold all assets of the subsidiaries as collateral. There is no recourse to third parties in the event these LOCs are drawn.

GUARANTEES OF THIRD-PARTY OBLIGATIONS

SWEPCo

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo has agreed, under certain conditions, to assume the capital lease obligations and term loan payments of the mining contractor, Sabine Mining Company (Sabine). In the event Sabine defaults under any of these agreements, SWEPCo's total future maximum payment exposure is approximately $54 million with maturity dates ranging from February 2007 to February 2012.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo has agreed to provide guarantees of mine reclamation in the amount of approximately $85 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by a third-party miner. At September 30, 2005, the cost to reclaim the mine in 2035 is estimated to be approximately $39 million. This guarantee ends upon depletion of reserves estimated at 2035 plus 6 years to complete reclamation.

INDEMNIFICATIONS AND OTHER GUARANTEES

Contracts

We entered into several types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price. We cannot estimate the maximum potential exposure for any of these indemnifications executed prior to December 31, 2002 due to the uncertainty of future events. In 2004 and the first nine months of 2005, we entered into several sale agreements. The status of certain sale agreements is discussed in Note 7. These sale agreements include indemnifications with a maximum exposure related to the collective purchase price, which is approximately $2.2 billion. There are no material liabilities recorded for any indemnifications.

Master Operating Lease

We lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, we committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At September 30, 2005, the maximum potential loss for this lease agreement was approximately $47 million ($31 million, net of tax) assuming the fair market value of the equipment is zero at the end of the lease term.

Railcar Lease

In June 2003, we entered into an agreement with an unrelated, unconsolidated leasing company to lease 875 coal-transporting aluminum railcars. The lease has an initial term of five years and may be renewed for up to three additional five-year terms for a maximum of twenty years. We intend to renew the lease for the full twenty years. At the end of each lease term, we may (a) renew for another five-year term, not to exceed a total of twenty years, (b) purchase the railcars for the purchase price amount specified in the lease, projected at the lease inception to be the then fair market value, or (c) return the railcars and