Dividends Paid on Common Stock	(27,000)	(26,250)
Dividends Paid on Cumulative Preferred Stock	(159)	(159)
Net Cash Flows Used For Financing Activities	(35,155)	(68,908)
Net Increase (Decrease) in Cash and Cash Equivalents	1,820	(228)
Cash and Cash Equivalents at Beginning of Period	91	3,738
Cash and Cash Equivalents at End of Period	$ 1,911	$ 3,510

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $21,954,000 and $24,518,000 and for income taxes was $14,241,000 and $2,387,000 in 2005 and 2004, respectively. Noncash capital lease acquisitions were $798,000 and $448,000 in 2005 and 2004, respectively. Construction Expenditures include the change in construction-related Accounts Payable of $1,004,000 and $(1,842,000) in 2005 and 2004, respectively.

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

PUBLIC SERVICE COMPANY OF OKLAHOMA
INDEX TO CONDENSED NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to PSO's condensed financial statements are combined with the condensed notes to financial statements for other subsidiary registrants. Listed below are the condensed notes that apply to PSO.

	Footnote Reference
Significant Accounting Matters	Note 1
New Accounting Pronouncements	Note 2
Rate Matters	Note 3
Commitments and Contingencies	Note 5
Guarantees	Note 6
Benefit Plans	Note 8
Business Segments	Note 9
Income Taxes	Note 10
Financing Activities	Note 11
Company-wide Staffing and Budget Review	Note 12

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

Results of Operations

Third Quarter of 2005 Compared to Third Quarter of 2004

Reconciliation of Third Quarter of 2004 to Third Quarter of 2005 Net Income
(in millions)

Third Quarter of 2004 Net Income		$ 47
Changes in Gross Margin:		
Retail and Off-system Sales Margins (a)	19	
Transmission Revenues	4	
Other Revenues	2	
Total Change in Gross Margin		25
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(20)	
Depreciation and Amortization	1	
Taxes Other Than Income Taxes	(2)	
Nonoperating Income and Expenses, Net	1	
Interest Charges	1	
Total Change in Operating Expenses and Other		(19)
Income Tax Expense		(3)
Third Quarter of 2005 Net Income		$ 50

(a) Includes firm wholesale sales to municipals and cooperatives.

Net Income increased $3 million to $50 million in the third quarter of 2005. The key drivers of the increase were a $25 million increase in gross margin partially offset by a $20 million increase in Other Operation and Maintenance expense and a $3 million increase in Income Tax Expense.

The major components of our increase in gross margin, defined as revenues net of related fuel and purchased power, were as follows:

- Retail and Off-system Sales Margins increased $19 million primarily due to an increase in both retail base margins and wholesale base margins due to higher volumes resulting primarily from a 32% increase in cooling degree days.
- Transmission Revenues increased $4 million due to increased SPP revenue.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expense increased $20 million primarily due to increased power plant operation and maintenance expense of $8 million resulting from extended planned power plant outages and higher transmission-related expense from SPP. Distribution maintenance expense increased $6 million primarily due to $4 million of storm damage related to Hurricane Rita and higher overhead line expense. Customer-related expenses and administrative and general expenses increased $6 million, offset in part by lower employee-related expenses.

Income Taxes

The effective tax rates for the third quarter of 2005 and 2004 were 34.1% and 32.8%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits, state income taxes and federal income tax adjustments. The effective tax rates remained relatively flat for the comparative period.

Nine Months Ended September 30, 2005 Compared to Nine Months Ended September 30, 2004

Reconciliation of Nine Months Ended September 30, 2004 to Nine Months Ended September 30, 2005 Net Income (in millions)

Nine Months Ended September 30, 2004 Net Income		$ 80
Changes in Gross Margin:		
Retail and Off-system Sales Margins (a)	11	
Transmission Revenues	4	
Other Revenues	4	
Total Change in Gross Margin		19
Changes in Operating Expenses and Other:		
Other Operation and Maintenance	(21)	
Depreciation and Amortization	(2)	
Interest Charges	4	
Total Change in Operating Expenses and Other		(19)
Income Tax Expense		1
Nine Months Ended September 30, 2005 Net Income		$ 81

(a) Includes firm wholesale sales to municipals and cooperatives.

Net Income increased $1 million to $81 million for the nine months ended September 30, 2005. The key drivers of the change were a $19 million increase in gross margin offset by a $21 million increase in Other Operation and Maintenance expense.

The major components of our increase in gross margin, defined as revenues net of related fuel and purchased power, were as follows:

- Retail and Off-system Sales Margins increased $11 million primarily due to an increase in both retail base margins and wholesale base margins due to higher volumes resulting primarily from a 10% increase in degree days. These margins were offset in part by unfavorable optimization activity and increased purchased capacity.
- Transmission Revenues increased $4 million primarily due to increased SPP revenues.

Operating Expenses and Other changed between years as follows:

- Other Operation and Maintenance expense increased $21 million primarily due to increased power plant operation and maintenance expense of $13 million resulting from extended planned power plant outages in 2005. This increase was partially offset by a $5 million adjustment in 2004 for affiliated OATT and ancillary services resulting from revised ERCOT data for the years 2001 through 2003. Distribution maintenance and customer expense increased $12 million primarily due to $4 million of storm damage related to Hurricane Rita and higher overhead line expense, offset in part by lower administrative and general and employee-related expenses.
- Interest Charges decreased $4 million primarily due to decreased long-term debt.

Income Taxes

The effective tax rates for the nine months ended September 30, 2005 and 2004 were 30.5% and 31.4%, respectively. The difference in the effective income tax rate and the federal statutory rate of 35% is due to permanent differences, amortization of investment tax credits, state income taxes and federal income tax adjustments. The effective tax rates remained relatively flat for the comparative period.

Financial Condition

Credit Ratings

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

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

Cash Flow

Cash flows for the nine months ended September 30, 2005 and 2004 were as follows:

	2005	2004
	(in thousands)	
Cash and Cash Equivalents at Beginning of Period	$ 2,308	$ 5,676
Cash Flows From (Used For):		
Operating Activities	160,994	214,921

Investing Activities	(105,557)	(63,535)
Financing Activities	(53,941)	(153,738)
Net Increase (Decrease) in Cash and Cash Equivalents	1,496	(2,352)
Cash and Cash Equivalents at End of Period	$ 3,804	$ 3,324

Operating Activities

Our Net Cash Flows From Operating Activities were $161 million in 2005. We produced income of $81 million during the period and noncash expense items of $99 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant are Accounts Payable and Customer Deposits. Accounts Payable increased $42 million primarily due to higher energy and fuel-related purchases. Customer Deposits increased $27 million primarily due to increased deposits for power trading customers.

Our Net Cash Flows From Operating Activities were $215 million in 2004. We produced income of $80 million during the period and noncash expense items of $97 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items; the most significant are Accounts Payable, Fuel, Materials and Supplies, and Taxes Accrued. Accounts Payable decreased $20 million related to lower vendor-related payables and lower energy transactions. Fuel, Materials and Supplies decreased $14 million primarily due to lower purchases of fuel. Taxes Accrued increased $64 million primarily due to the annual tax accruals related to 2004 property taxes and by an increase of income tax-related accruals.

Investing Activities

Net Cash Flows Used For Investing Activities during 2005 and 2004 were $106 million and $64 million, respectively. They were comprised of Construction Expenditures related to projects for improved transmission and distribution service reliability. For the remainder of 2005, we expect our Construction Expenditures to be approximately $100 million.

Financing Activities

Net Cash Flows Used For Financing Activities were $54 million during 2005. During the nine months ended September 30, 2005, we borrowed $40 million from the Utility Money Pool, issued Senior Unsecured Notes for $150 million for the purpose of funding the July 1, 2005 maturity of our $200 million Senior Unsecured Notes and retired $8 million of Notes Payable. Common stock dividends were $40 million.

Net Cash Flows Used For Financing Activities were $154 million during 2004. During the nine months ended September 30, 2004, we decreased our Utility Money Pool borrowing by $29 million, retired $120 million of First Mortgage Bonds, retired $7 million of Notes Payable, replaced $95 million of

Installment Purchase Contracts with lower variable interest rate long-term debt of the same principal amount and paid $45 million in common stock dividends.

Financing Activity

Long-term issuances and retirements during the first nine months of 2005 were:

Issuances

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Senior Unsecured Notes	$ 150,000	4.90	2015
Notes Payable	5,771	Variable	2006

Retirements

Type of Debt	Principal Amount	Interest Rate	Due Date
	(in thousands)	(%)	
Notes Payable	$ 5,122	4.47	2011
Notes Payable	3,000	Variable	2008
Senior Unsecured Notes	200,000	4.50	2005

Liquidity

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

Summary Obligation Information

A summary of our contractual obligations is included in our 2004 Annual Report and has not changed significantly from year-end other than the issuances and retirements discussed above.

Significant Factors

Generation

In September 2005, we began seeking proposals for new generation to supplement existing power supply resources to effectively meet customers' power demand requirements. The proposals will be evaluated along with our self-build options to meet short-term and long-term capacity needs.

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

Critical Accounting Estimates

See "Critical Accounting Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2004 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and the impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

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

MTM Risk Management Contract Net Assets

This table provides detail on changes in our MTM net asset or liability balance sheet position from one period to the next.

MTM Risk Management Contract Net Assets
Nine Months Ended September 30, 2005
(in thousands)

Total MTM Risk Management Contract Net Assets at December 31, 2004	$	17,527
(Gain) Loss from Contracts Realized/Settled During the Period (a)		(3,653)
Fair Value of New Contracts When Entered During the Period (b)		47
Net Option Premiums Paid/(Received) (c)		(326)
Change in Fair Value Due to Valuation Methodology Changes		-
Changes in Fair Value of Risk Management Contracts (d)		4,510
Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions (e)		2,563
Total MTM Risk Management Contract Net Assets		20,668
Net Cash Flow Hedge Contracts (f)		(6,921)
Total MTM Risk Management Contract Net Assets at September 30, 2005	$	13,747

(a) "(Gain) Loss from Contracts Realized/Settled During the Period" includes realized risk management contracts and related derivatives that settled during 2005 where we entered into the contract prior to 2005.

(b) "Fair Value of New Contracts When Entered During the Period" represents the fair value at inception of long-term contracts entered into with customers during 2005. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. Inception value is only recorded if observable market data can be obtained for valuation inputs for the entire contract term. The contract prices are valued against market curves associated with the delivery location and delivery term.

(c) "Net Option Premiums Paid/(Received)" reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered in 2005.

(d) "Changes in Fair Value of Risk Management Contracts" represents the fair value change in the risk management portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.

(e) "Changes in Fair Value of Risk Management Contracts Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected in the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities for those subsidiaries that operate in regulated jurisdictions.

(f) "Net Cash Flow Hedge Contracts" (pretax) are discussed below in Accumulated Other Comprehensive Income (Loss).

Reconciliation of MTM Risk Management Contracts to
Condensed Consolidated Balance Sheets
As of September 30, 2005
(in thousands)

	MTM Risk Management Contracts (a)	Cash Flow Hedges	Total (b)
Current Assets	$ 62,400	$ 176	$ 62,576
Noncurrent Assets	38,031	194	38,225
Total MTM Derivative Contract Assets	100,431	370	100,801
Current Liabilities	(55,023)	(6,975)	(61,998)
Noncurrent Liabilities	(24,740)	(316)	(25,056)
Total MTM Derivative Contract Liabilities	(79,763)	(7,291)	(87,054)
Total MTM Derivative Contract Net Assets (Liabilities)	$ 20,668	$ (6,921)	$ 13,747

(a) Does not include Cash Flow Hedges.

(b) Represents amount of total MTM derivative contracts recorded within Risk Management Assets, Long-term Risk Management Assets, Risk Management Liabilities and Long-term Risk Management Liabilities on our Condensed Consolidated Balance Sheets.

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

The table presenting maturity and source of fair value of MTM risk management contract net assets provides two fundamental pieces of information:

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

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

Fair Value of Contracts as of September 30, 2005
(in thousands)

	Remainder of 2005	2006	2007	2008	2009	After 2009	Total (c)
Prices Actively Quoted - Exchange Traded Contracts	$ (1,199)	$ 5,769	$ 485	$ 266	$ -	$ -	$ 5,321
Prices Provided by Other External Sources - OTC Broker Quotes (a)	8,890	3,056	7,564	2,665	-	-	22,175
Prices Based on Models and Other Valuation Methods (b)	(1,198)	(6,978)	(4,928)	680	2,667	2,929	(6,828)
Total	$ 6,493	$ 1,847	$ 3,121	$3,611	$2,667	$2,929	$20,668

(a) "Prices Provided by Other External Sources - OTC Broker Quotes" reflects information obtained from over-the-counter brokers, industry services, or multiple-party on-line platforms.
(b) "Prices Based on Models and Other Valuation Methods" is in absence of pricing information from external sources. Modeled information is derived using valuation models developed by the reporting entity, reflecting when appropriate, option pricing theory, discounted cash flow concepts, valuation adjustments, etc. and may require projection of prices for underlying commodities beyond the period that prices are available from third-party sources. In addition, where external pricing information or market liquidity are limited, such valuations are classified as modeled. The determination of the point at which a market is no longer liquid for placing it in the modeled category varies by market.
(c) Amounts exclude Cash Flow Hedges.

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

We are exposed to market fluctuations in energy commodity prices impacting our power operations. We monitor these risks on our future operations and may 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 exposure on anticipated borrowings of fixed-rate debt. We do not hedge all interest rate exposure.

The table provides detail on designated, effective cash flow hedges included in the Condensed Consolidated Balance Sheets. The data in the table indicates the magnitude of cash flow hedges 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.

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

	Power	Interest Rate	Total
Beginning Balance December 31, 2004	$ 1,188	$ (2,008)	$ (820)
Changes in Fair Value (a)	(5,452)	(3,378)	(8,830)
Reclassifications from AOCI to Net Income (b)	(270)	135	(135)
Ending Balance September 30, 2005	$ (4,534)	$ (5,251)	$ (9,785)

(a) "Changes in Fair Value" shows 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.

(b) "Reclassifications from AOCI to Net Income" represents 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 above.

The portion of cash flow hedges in AOCI expected to be reclassified to earnings during the next twelve months is a $5,063 thousand loss.

Credit Risk

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

VaR Associated with Risk Management Contracts

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

Nine Months Ended September 30, 2005 (in thousands)				Twelve Months Ended December 31, 2004 (in thousands)			
End	High	Average	Low	End	High	Average	Low
$423	$577	$272	$145	$283	$923	$398	$136

VaR Associated with Debt Outstanding

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 $31 million and $31 million at September 30, 2005 and December 31, 2004, respectively. We would not expect to liquidate our entire debt portfolio in a one-year holding period. Therefore, a near term change in interest rates should not negatively affect our results of operation or consolidated financial position.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2005 and 2004
(Unaudited)
(in thousands)

	Three Months Ended		Nine Months Ended	
	2005	**2004**	**2005**	**2004**
OPERATING REVENUES				
Electric Generation, Transmission and Distribution	$ 459,083	$ 316,679	$ 1,015,132	$ 782,179
Sales to AEP Affiliates	14,614	14,888	38,573	54,597
TOTAL	473,697	331,567	1,053,705	836,776
OPERATING EXPENSES				
Fuel for Electric Generation	179,598	109,468	385,875	292,536
Purchased Electricity for Resale	45,194	18,958	91,377	20,884
Purchased Electricity from AEP Affiliates	27,363	6,685	55,230	21,105
Other Operation	59,966	46,825	151,530	141,686
Maintenance	22,353	15,350	65,713	55,009
Depreciation and Amortization	32,930	33,676	98,580	96,940
Taxes Other Than Income Taxes	18,175	16,544	49,725	48,259
Income Taxes	25,896	23,443	36,353	38,013
TOTAL	411,475	270,949	934,383	714,432
OPERATING INCOME	62,222	60,618	119,322	122,344
Nonoperating Income	1,256	704	3,566	2,899
Nonoperating Expenses	473	669	1,564	2,003
Nonoperating Income Tax Credit	107	398	678	1,295
Interest Charges	12,346	12,944	38,027	41,766
Minority Interest	(1,035)	(898)	(2,735)	(2,592)
NET INCOME	49,731	47,209	81,240	80,177
Preferred Stock Dividend Requirements	57	57	172	172
EARNINGS APPLICABLE TO COMMON STOCK	$ 49,674	$ 47,152	$ 81,068	$ 80,005

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

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 30, 2005 and 2004
(Unaudited)
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2003	$ 135,660	$245,003	$ 359,907	$ (43,910)	$696,660
Common Stock Dividends			(45,000)		(45,000)
Preferred Stock Dividends			(172)		(172)
TOTAL					651,488
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $2,189				(4,064)	(4,064)
Minimum Pension Liability, Net of Tax of $12,420				23,066	23,066
NET INCOME			80,177		80,177
TOTAL COMPREHENSIVE INCOME					99,179
SEPTEMBER 30, 2004	$ 135,660	$245,003	$ 394,912	$ (24,908)	$750,667
DECEMBER 31, 2004	$ 135,660	$245,003	$ 389,135	$ (1,180)	$768,618
Common Stock Dividends			(40,000)		(40,000)
Preferred Stock Dividends			(172)		(172)
TOTAL					728,446
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $4,827				(8,965)	(8,965)
NET INCOME			81,240		81,240
TOTAL COMPREHENSIVE INCOME					72,275

SEPTEMBER 30, 2005	$ 135,660	$245,003	$ 430,203	$ (10,145)	$800,721

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2005 and December 31, 2004
(Unaudited)
(in thousands)

	2005	2004
ELECTRIC UTILITY PLANT		
Production	$ 1,664,614	$ 1,663,161
Transmission	641,282	632,964
Distribution	1,144,445	1,114,480
General	435,727	427,910
Construction Work in Progress	75,491	48,852
Total	3,961,559	3,887,367
Accumulated Depreciation and Amortization	1,762,337	1,709,758
TOTAL - NET	2,199,222	2,177,609
OTHER PROPERTY AND INVESTMENTS		
Nonutility Property, Net	4,047	4,049
Other Investments	4,611	4,628
TOTAL	8,658	8,677
CURRENT ASSETS		
Cash and Cash Equivalents	3,804	2,308
Other Cash Deposits	1,748	6,292
Advances to Affiliates	-	39,106
Accounts Receivable:		
Customers	35,940	39,042
Affiliated Companies	36,050	28,817
Miscellaneous	6,329	5,856
Allowance for Uncollectible Accounts	(383)	(45)
Fuel Inventory	38,883	45,793
Materials and Supplies	36,707	36,051
Risk Management Assets	62,576	25,379
Regulatory Asset for Under-Recovered Fuel Costs	62,738	4,687
Margin Deposits	22,185	3,419
Prepayments and Other	24,577	18,331
TOTAL	331,154	255,036

DEFERRED DEBITS AND OTHER ASSETS

Regulatory Assets:		
SFAS 109 Regulatory Asset, Net	22,826	18,000
Unamortized Loss on Reacquired Debt	18,671	20,765
Other	28,528	16,350
Long-term Risk Management Assets	38,225	17,179
Prepaid Pension Obligations	80,255	81,132
Deferred Property Taxes	9,579	-
Deferred Charges and Other	44,919	51,561
TOTAL	243,003	204,987
TOTAL ASSETS	$ 2,782,037	$ 2,646,309

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES
September 30, 2005 and December 31, 2004
(Unaudited)

	2005	2004
CAPITALIZATION	(in thousands)	
Common Shareholder's Equity:		
Common Stock - $18 par value per share:		
Authorized - 7,600,000 shares		
Outstanding - 7,536,640 shares	$ 135,660	$ 135,660
Paid-in Capital	245,003	245,003
Retained Earnings	430,203	389,135
Accumulated Other Comprehensive Income (Loss)	(10,145)	(1,180)
Total Common Shareholder's Equity	800,721	768,618
Cumulative Preferred Stock Not Subject to Mandatory Redemption	4,700	4,700
Total Shareholders' Equity	805,421	773,318
Long-term Debt:		
Nonaffiliated	687,376	545,395
Affiliated	50,000	50,000
Total Long-term Debt	737,376	595,395
TOTAL	1,542,797	1,368,713
Minority Interest	1,607	1,125
CURRENT LIABILITIES		
Long-term Debt Due Within One Year - Nonaffiliated	15,663	209,974
Advances from Affiliates	605	-
Accounts Payable:		
General	87,889	40,001
Affiliated Companies	27,155	33,285
Customer Deposits	57,121	30,550
Taxes Accrued	50,129	45,474
Interest Accrued	11,851	12,509
Risk Management Liabilities	61,998	18,607
Obligations Under Capital Leases	5,021	3,692
Regulatory Liability for Over-Recovered Fuel Costs	1,769	9,891
Other	36,792	33,417
TOTAL	355,993	437,400

DEFERRED CREDITS AND OTHER LIABILITIES

Deferred Income Taxes	411,467	399,756
Long-term Risk Management Liabilities	25,056	9,128
Reclamation Reserve	-	7,624
Regulatory Liabilities:		
Asset Removal Costs	257,573	249,892
Deferred Investment Tax Credits	32,319	35,539
Excess Earnings	3,167	3,167
Other	33,809	21,320
Asset Retirement Obligations	33,743	27,361
Obligations Under Capital Leases	34,250	30,854
Deferred Credits and Other	50,256	54,430
TOTAL	881,640	839,071
Commitments and Contingencies (Note 5)		
TOTAL CAPITALIZATION AND LIABILITIES	$ 2,782,037	$ 2,646,309

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2005 and 2004
(Unaudited)
(in thousands)

	2005	2004
OPERATING ACTIVITIES		
Net Income	$ 81,240	$ 80,177
Adjustments to Reconcile Net Income to Net Cash Flows From Operating Activities:		
Depreciation and Amortization	98,580	96,940
Deferred Property Taxes	(9,579)	(9,687)
Deferred Income Taxes	11,552	(7,303)
Deferred Investment Tax Credits	(3,220)	(3,244)
Pension and Postemployment Benefit Reserves	(116)	3,103
Mark-to-Market of Risk Management Contracts	(3,141)	4,712
Pension Contributions	(231)	(3,463)
Change in Other Noncurrent Assets	(13,329)	(7,485)
Change in Other Noncurrent Liabilities	11,005	10,425
Changes in Components of Working Capital:		
Accounts Receivable, Net	(4,266)	(9,812)
Fuel, Materials and Supplies	6,254	14,525
Over/Under Fuel Recovery	(66,173)	12,304
Accounts Payable	42,158	(20,066)
Taxes Accrued	4,655	63,540
Customer Deposits	26,571	7,873
Interest Accrued	(658)	(4,885)
Other Current Assets	(25,012)	2,940
Other Current Liabilities	4,704	(15,673)
Net Cash Flows From Operating Activities	160,994	214,921
INVESTING ACTIVITIES		
Construction Expenditures	(110,209)	(68,216)
Change in Other Cash Deposits, Net	4,544	805
Proceeds from Sale of Assets	108	3,876
Net Cash Flows Used For Investing Activities	(105,557)	(63,535)
FINANCING ACTIVITIES		
Issuance of Long-term Debt-Nonaffiliated	154,642	92,441
Issuance of Long-term Debt-Affiliated	-	50,000
Retirement of Long-term Debt	(208,122)	(222,457)

Changes in Advances to/from Affiliates, Net	39,711	(28,550)
Dividends Paid on Common Stock	(40,000)	(45,000)
Dividends Paid on Cumulative Preferred Stock	(172)	(172)
Net Cash Flows Used For Financing Activities	(53,941)	(153,738)
Net Increase (Decrease) in Cash and Cash Equivalents	1,496	(2,352)
Cash and Cash Equivalents at Beginning of Period	2,308	5,676
Cash and Cash Equivalents at End of Period	$ 3,804	$ 3,324

SUPPLEMENTAL DISCLOSURE:
Cash paid for interest net of capitalized amounts was $33,748,000 and $40,136,000 and for income taxes was $49,176,000 and $11,326,000 in 2005 and 2004, respectively. Noncash capital lease acquisitions were $4,414,000 and $18,018,000 in 2005 and 2004, respectively. Construction Expenditures include the change in construction-related Accounts Payable of $(400,000) and $(321,000) in 2005 and 2004, respectively.

See Condensed Notes to Financial Statements of Registrant Subsidiaries.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED INDEX TO CONDENSED NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to SWEPCo's condensed consolidated financial statements are combined with the condensed notes to financial statements for other subsidiary registrants. Listed below are the condensed notes that apply to SWEPCo.

	Footnote Reference
Significant Accounting Matters	Note 1
New Accounting Pronouncements	Note 2
Rate Matters	Note 3
Commitments and Contingencies	Note 5
Guarantees	Note 6
Benefit Plans	Note 8
Business Segments	Note 9
Income Taxes	Note 10
Financing Activities	Note 11
Company-wide Staffing and Budget Review	Note 12

CONDENSED NOTES TO FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to financial statements that follow are a combined presentation for AEP's registrant subsidiaries. The following list indicates the registrants to which the footnotes apply:

1. Significant Accounting Matters	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
2. New Accounting Pronouncements	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
3. Rate Matters	APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
4. Customer Choice and Industry Restructuring	CSPCo, OPCo, TCC, TNC
5. Commitments and Contingencies	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
6. Guarantees	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
7. Acquisitions, Dispositions, Asset Impairments and Assets Held for Sale	APCo, CSPCo, TCC
8. Benefit Plans	APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
9. Business Segments	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
10. Income Taxes	APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
11. Financing Activities	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC
12. Company-wide Staffing and Budget Review	AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC, TNC

1. SIGNIFICANT ACCOUNTING MATTERS

General

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

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

Components of Accumulated Other Comprehensive Income (Loss)

Accumulated Other Comprehensive Income (Loss) is included on the balance sheet in the capitalization section. The components of Accumulated Other Comprehensive Income (Loss) for Registrant Subsidiaries are shown in the following table:

Components	September 30, 2005 (in thousands)	December 31, 2004
Cash Flow Hedges:		
APCo	$ (24,814)	$ (9,324)
CSPCo	(5,396)	1,393
I&M	(9,461)	(4,076)
KPCo	(2,035)	813
OPCo	(7,561)	1,241
PSO	(4,394)	400
SWEPCo	(9,785)	(820)
TCC	(2,364)	657
TNC	(1,011)	285
Minimum Pension Liability:		
APCo	$ (72,348)	$ (72,348)
CSPCo	(62,209)	(62,209)
I&M	(41,175)	(41,175)
KPCo	(9,588)	(9,588)
OPCo	(75,505)	(75,505)
PSO	(325)	(325)
SWEPCo	(360)	(360)
TCC	(1,006)	(4,816)
TNC	(413)	(413)

Accounting for Asset Retirement Obligations (ARO)

All of AEP's Registrant Subsidiaries implemented SFAS 143, "Accounting for Asset Retirement Obligations," effective January 1, 2003, which requires entities to record a liability at fair value for any legal obligations for asset retirements in the period incurred. Upon establishment of a legal liability, SFAS 143 requires a corresponding asset to be established which will be depreciated over its useful life.

The following is a reconciliation of beginning and ending aggregate carrying amounts of ARO by Registrant Subsidiary:

	Balance at January 1, 2005	Accretion	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	Balance at September 30, 2005
			(in millions)			
AEGCo (a)	$ 1.2	$ 0.1	$ -	$ -	$ -	$ 1.3
APCo (a)	24.6	1.4	-	-	-	26.0
CSPCo (a)	11.6	0.6	-	-	-	12.2
I&M (b)	711.8	35.7	-	-	(27.0)	720.5
OPCo (a)	45.6	2.7	-	-	-	48.3
SWEPCo (c)	27.4	1.1	8.8	(0.1)	(0.8)	36.4
TCC (d)	248.9	7.5	-	(256.4)	-	-

(a) Consists of ARO related to ash ponds.
(b) Consists of ARO related to ash ponds ($1.3 million at September 30, 2005) and nuclear decommissioning costs for the Cook Plant ($719.2 million at September 30, 2005). The Cook Plant's operating licenses were renewed for Cook Unit 1 until 2034 and for Cook Unit 2 until 2037.
(c) Consists of ARO related to Sabine Mining Company and Dolet Hills Lignite Company, LLC (Dolet Hills). The current portion of Dolet Hills ARO, totaling $2.6 million, is included in Other in the Current Liabilities section of SWEPCo's September 30, 2005 Condensed Consolidated Balance Sheet.
(d) The ARO for TCC's share of STP was included in Liabilities Held for Sale - Texas Generation Plants in TCC's Consolidated Balance Sheet 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).

Accretion expense is included in Other Operation expense in the respective income statements of tł individual Registrant Subsidiaries.

As of September 30, 2005 and December 31, 2004, the fair value of assets that are legally restricted for purposes of settling I&M's nuclear decommissioning liabilities totaled $855 million and $791 million, respectively, and were recorded in Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds on I&M's Condensed Consolidated Balance Sheets.

Related Party Transactions

The amounts of power purchased from Ohio Valley Electric Corporation, which is 44.2% owned by AEP and CSPCo, were:

Company	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
	(in thousands)			
APCo	$ 19,501	$ 16,647	$ 54,763	$ 44,276
CSPCo	5,103	4,468	14,752	11,956
I&M	7,920	9,042	22,704	19,438
OPCo	16,703	14,938	47,757	39,501

CSPCo entered into a ten year Power Purchase Agreement (PPA) with Sweeny, on behalf of the AEP West companies, from January 1, 2005 to December 31, 2014. The PPA is for unit contingent power up to a maximum of 315 MW. The delivery point for the power under the PPA is in TCC's system. The power is sold in ERCOT. The purchase of Sweeny power and its sale to nonaffiliates are shared among the AEP West companies under the CSW Operating Agreement. Refer to Note 17 of the 2004 Annual Report for a discussion of the CSW Operating Agreement. The purchases from Sweeny were:

Company	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
	(in thousands)			
PSO	$ 11,051	$ -	$ 31,160	$ -
SWEPCo	13,189	-	27,570	-
TCC	5,548	-	20,120	-
TNC	8,559	-	19,638	-

Reclassification

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 (Loss).

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 applying the statement.

The Registrant Subsidiaries 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. The Registrant Subsidiaries do not expect implementation of SFAS 123R to materially affect their 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. The Registrant Subsidiaries will apply the principles of SAB 107 in conjunction with their 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 the Registrant Subsidiaries 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.

The Registrant Subsidiaries 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. The Registrant Subsidiaries have not completed their evaluation of any potential impact to their results of operations or financial condition.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by FASB, management cannot determine the impact on the reporting of 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, pension plans, fair value measurements and related tax impacts. Management also expects to see more FASB projects as a result of the FASB's desire to converge International Accounting Standards with those generally accepted in the United States of America. The ultimate pronouncements resulting from these and future projects could have an impact on future results of operations and financial position.

3. RATE MATTERS

As discussed in the 2004 Annual Report, certain AEP subsidiaries are involved in rate and regulatory proceedings at the FERC and at state commissions. The Rate Matters note within the 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 - Affecting APCo

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 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. E&R costs of $4 million represented interest capitalized 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 APCo's future results of operations and cash flows.

***APCo West Virginia Rate Case* - Affecting APCo**

On August 26, 2005, APCo in a joint filing with WPCo, filed an application with the Public Service Commission of West Virginia seeking an initial increase in APCo's retail rates of approximately $77 million. The initial increase included approval to reactivate and modify the Expanded Net Energy Cost (ENEC) Recovery Mechanism which accounted for $65 million of the initial increase and approval to implement a system reliability tracker which accounted for $9 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 supplemental increase of $9 million would go in effect on the same date as the initial rate increase, and the remaining 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 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 APCo's future revenues, results of operations, cash flows and financial condition.

I&M Indiana Settlement Agreement - Affecting I&M

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, I&M's future results of operations and cash flows would be adversely affected.

I&M Michigan Fuel Recovery Plan - Affecting I&M

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 - Affecting KPCo

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. Management is unable to predict the ultimate effect of this filing on KPCo's future revenues, results of operations, cash flows and financial condition.

PSO Fuel and Purchased Power - Affecting PSO

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, PSO's 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, PSO also believes 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 PSO's revenues, results of operations, cash flows and financial condition.

PSO Lawton Power Supply Agreement - Affecting PSO

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. Management is 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 PSO's 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 - Affecting PSO

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 Texas Fuel Factor Filing - Affecting SWEPCo

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.

SWEPCo and TNC PUCT Staff Review of Earnings - Affecting SWEPCo and TNC

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 Louisiana Fuel Audit - Affecting SWEPCo

The Louisiana Public Service Commission (LPSC) performed an audit of SWEPCo's fuel costs for the years 1999 through 2002. On July 22, 2005, the LPSC approved the uncontested settlement in that proceeding, which required SWEPCO to refund approximately $18 thousand for the four-year period. The LPSC also recommended that the $18 thousand be donated to the United Way to assist needy customers.

TCC Rate Case - Affecting TCC

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 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 - Affecting TCC and TNC

Several parties including the Office of Public Utility Counsel and cities served by both TCC and TNC appealed the PUCT's December 2001 orders establishing initial PTB fuel factors for Mutual Energy CPL and Mutual Energy WTU (TCC's and TNC's former affiliated REPs, respectively). In June 2003, the District Court ruled 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. AEP's 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 - Affecting TCC

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, management is 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 - Affecting APCo, CSPCo, I&M, KPCo and OPCo

In a July 2002 order conditionally accepting AEP's 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 AEP 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, their future results of operations and cash flows will be adversely affected.

FERC Order on Regional Through and Out Rates - Affecting APCo, CSPCo, I&M, KPCo and OPCo

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. The FERC has set the SECA rate issue for hearing and indicated that the SECA rates are being recovered subject to refund. Intervenors in that proceeding are objecting to the SECA rates and AEP's method of determining those rates. Management is unable to determine the probable outcome of the FERC's SECA rate proceeding. SECA revenues by Registrant Subsidiary are shown in the following table:

Company	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2005	December 2004
		(in millions)	
APCo	$ 11.3	$ 30.3	$ 3.5
CSPCo	6.4	16.1	2.0
I&M	6.6	17.4	2.3
KPCo	2.7	7.2	0.8
OPCo	8.8	22.3	2.8

In a March 31, 2005 FERC filing, AEP 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 investigation provides AEP an opportunity to propose and support a new PJM rate regime.

As of September 30, 2003, 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 - Affecting APCo, CSPCo, I&M, KPCo and OPCo

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 join an existing RTO (PJM). 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 AEP's application. The formation and integration costs included in AEP's application by company follows:

Company	PJM-Billed Integration Costs	Non-PJM Billed Formation/ Integration Costs
	(in millions)	
APCo	$ 4.8	$ 5.1
CSPCo	2.0	2.2
I&M	3.8	3.8
KPCo	1.1	1.1
OPCo	5.5	5.7

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 (the latter, 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 as follows:

	PJM-Billed	Non-PJM Billed Formation/

Company	Integration Costs	Integration Costs
	(in millions)	
APCo	$ 4.9	$ 4.8
CSPCo	2.0	2.0
I&M	3.8	3.5
KPCo	1.2	1.1
OPCo	5.6	5.3

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 AEP's 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, AEP 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 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. CSPCo, OPCo, APCo and KPCo 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 the AEP East companies' 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, AEP filed on November 1, 2005, 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 the sharing of all such margins among all AEP East and AEP West companies. The allocation ultimately approved by the FERC may differ from the one proposed. AEP requested that the new methodology be effective on a prospective basis after the FERC's order. Management is unable to predict the ultimate effect of this filing on the AEP East and AEP West companies' future results of operations and cash flows because the impact will depend upon the ultimate methodology approved by the FERC and the level of future trading and marketing margins.

4. CUSTOMER CHOICE AND INDUSTRY RESTRUCTURING

Certain AEP subsidiaries are affected by customer choice initiatives and industry restructuring. The Customer Choice and Industry Restructuring note in the 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 - Affecting CSPCo and OPCo

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's 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 management believes that the RSP plan is legal and intends to defend vigorously the PUCO's order, management cannot predict the ultimate outcome of the pending litigation.

The PUCO's order in the RSP requires CSPCo and OPCo to allot a combined total of $14 million of previously provided for unused CSPCo shopping incentives to benefit their low-income customers and economic development programs over the three-year period ending December 31, 2008. In a March 23, 2005 rehearing order, the PUCO clarified that the Ohio companies have a regulatory liability of only $14 million of unused shopping incentives. In the second quarter of 2005, CSPCo ceased applying unused shopping incentives to reduce its recoverable transition regulatory asset. Assuming that the $14 million regulatory liability is allocated equally to CSPCo and OPCo, in the second quarter of 2005, CSPCo increased its recoverable transition regulatory asset by $18 million due to the reversal of the unused shopping incentives, transferred $7 million to a regulatory liability and credited the remaining $11 million to pretax earnings and OPCo recorded a regulatory liability of $7 million which it charged to pretax earnings.

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 the Ohio companies' future results of operations and cash flows.

As provided in stipulation agreements approved by the PUCO in 2000, the Ohio companies 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, CSPCo and OPCo incurred $42 million and $44 million, respectively, of such costs, and accordingly, deferred $22 million and $24 million, respectively, 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. Management believes 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 the Ohio companies' future results of operations and cash flows.

TEXAS RESTRUCTURING - Affecting TCC and TNC

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, TCC does 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 TCC's 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. TCC is 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 Carrying Costs on Stranded Cost Recovery on TCC's 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 TCC's 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 TCC to refund excess earnings as determined in its 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.

TCC believes that its 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 TCC's 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 TCC's interpretation and application of the Texas Restructuring Legislation and 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 TCC's 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. TNC is unable to predict whether the PUCT will appeal the Federal District Court decision and/or file a complaint at FERC, nor is it 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 the 2004 Annual Report, certain Registrant Subsidiaries 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 their 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 and (4) FERC long-term contracts. See disclosure below for significant matters with changes in status subsequent to the disclosure made in the 2004 Annual Report.

ENVIRONMENTAL

Federal EPA Complaint and Notice of Violation - Affecting APCo, CSPCo, I&M, and OPCo

The Federal EPA and a number of states 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 AEP subsidiaries in U.S. District Court for the Southern District of Ohio. The court also consolidated a separate lawsuit, initiated by certain special interest groups, with the Federal EPA case. The alleged modifications occurred at the 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 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 (NSR) 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 the AEP 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 the AEP 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 the AEP 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 an actual-to-future actual emissions, and includes test, 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.

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

SWEPCo Notice of Enforcement and Notice of Citizen Suit - Affecting SWEPCo

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 $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 $6 thousand against SWEPCo based on alleged violations of certain permit