

AEP Texas Central Company and Subsidiaries

2007 Annual Report

Consolidated Financial Statements



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GLOSSARY OF TERMS

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

Term	Meaning
AEP or Parent	American Electric Power Company, Inc.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, asset management and commercial and industrial sales in the deregulated Texas market.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AFUDC	Allowance for Funds Used During Construction.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ARO	Asset Retirement Obligations.
CAA	Clean Air Act.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CSW Operating Agreement	Agreement, dated January 1, 1997, by and among PSO, SWEPCo, TCC and TNC governing generating capacity allocation. This agreement was amended in May 2006 to remove TCC and TNC. AEPSC acts as the agent.
CTC	Competition Transition Charge.
CWIP	Construction Work in Progress.
EITF	Financial Accounting Standards Board's Emerging Issues Task Force.
ERCOT	Electric Reliability Council of Texas.
ETT	Electric Transmission Texas, LLC, a 50% equity interest joint venture with MidAmerican Energy Holdings Company formed to own and operate electric transmission facilities in ERCOT.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN	FASB Interpretation No.
FIN 47	FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations."
FIN 48	FIN 48, "Accounting for Uncertainty in Income Taxes" and FASB Staff Position FIN 48-1 "Definition of <i>Settlement</i> in FASB Interpretation No. 48."
GAAP	Accounting Principles Generally Accepted in the United States of America.
IRS	Internal Revenue Service.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
KGPCo	Kingsport Power Company, an AEP electric distribution subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
kV	Kilovolt.

Term	Meaning
MTM	Mark-to-Market.
MW	Megawatt.
OATT	Open Access Transmission Tariff.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCT	Public Utility Commission of Texas.
PUHCA	Public Utility Holding Company Act.
REP	Texas Retail Electric Provider.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
RTO	Regional Transmission Organization.
SEC	United States Securities and Exchange Commission.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SFAS 71	Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation."
SFAS 109	Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes."
SFAS 133	Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities."
SFAS 143	Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations."
SFAS 157	Statement of Financial Accounting Standards No. 157, "Fair Value Measurements."
SFAS 158	Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans."
SFAS 159	Statement of Financial Accounting Standards No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities."
SIA	System Integration Agreement.
SPP	Southwest Power Pool.
STP	South Texas Project Nuclear Generating Plant.
Sweeny	Sweeny Cogeneration Limited Partnership, owner and operator of a four unit, 480 MW gas-fired generation facility, owned 50% by AEP.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
True-up Proceeding	A filing made under the Texas Restructuring Legislation to finalize the amount of stranded costs and other true-up items and the recovery of such amounts.
Utility Money Pool	AEP System's Utility Money Pool.

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Shareholders of
AEP Texas Central Company:

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

We conducted our audits in accordance with generally accepted auditing standards as established by the Auditing Standards Board (United States) and in accordance with the auditing standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of AEP Texas Central Company and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed in Notes 2 and 8 to the consolidated financial statements, respectively, the Company adopted FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes", effective January 1, 2007, and FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans," effective December 31, 2006.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2008

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2007, 2006 and 2005
(in thousands)

	2007	2006	2005
REVENUES			
Electric Generation, Transmission and Distribution	\$ 785,163	\$ 623,840	\$ 729,815
Sales to AEP Affiliates	5,690	6,403	14,973
Other	17,752	34,421	48,458
TOTAL	808,605	664,664	793,246
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	287	6,668	13,447
Purchased Electricity for Resale	3,583	4,093	28,947
Other Operation	237,326	240,795	286,708
Maintenance	38,920	38,466	50,888
Depreciation and Amortization	214,470	164,773	146,258
Taxes Other Than Income Taxes	74,450	80,772	89,717
TOTAL	569,036	535,567	615,965
OPERATING INCOME	239,569	129,097	177,281
Other Income (Expense):			
Interest Income	15,629	7,488	16,228
Carrying Costs Income (Expense)	-	69,080	(19,293)
Allowance for Equity Funds Used During Construction	3,232	2,688	1,003
Interest Expense	(180,467)	(144,134)	(112,006)
INCOME BEFORE INCOME TAXES	77,963	64,219	63,213
Income Tax Expense	19,013	22,650	12,441
INCOME BEFORE EXTRAORDINARY LOSS	58,950	41,569	50,772
EXTRAORDINARY LOSS ON STRANDED COST RECOVERY, NET OF TAX	-	-	(224,551)
NET INCOME (LOSS)	58,950	41,569	(173,779)
Preferred Stock Dividend Requirements	240	241	241
Gain on Reacquired Preferred Stock	-	6	-
EARNINGS (LOSS) APPLICABLE TO COMMON STOCK	\$ 58,710	\$ 41,334	\$ (174,020)

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

See Notes to Consolidated Financial Statements.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2007, 2006 and 2005
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2004	\$ 55,292	\$ 132,606	\$ 1,084,904	\$ (4,159)	\$ 1,268,643
Common Stock Dividends			(150,000)		(150,000)
Preferred Stock Dividends			(241)		(241)
TOTAL					1,118,402
COMPREHENSIVE LOSS					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of \$474				(881)	(881)
Minimum Pension Liability, Net of Tax of \$42				3,888	3,888
NET LOSS			(173,779)		(173,779)
TOTAL COMPREHENSIVE LOSS					(170,772)
DECEMBER 31, 2005	55,292	132,606	760,884	(1,152)	947,630
Common Stock Dividends			(585,000)		(585,000)
Preferred Stock Dividends			(241)		(241)
Gain on Reacquired Preferred Stock			6		6
TOTAL					362,395
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of \$121				224	224
Minimum Pension Liability, Net of Tax of \$108				200	200
NET INCOME			41,569		41,569
TOTAL COMPREHENSIVE INCOME					41,993
Minimum Pension Liability Elimination, Net of Tax of \$392				728	728
DECEMBER 31, 2006	55,292	132,606	217,218	-	405,116
FIN 48 Adoption, Net of Tax			(2,187)		(2,187)
Common Stock Dividends			(3,000)		(3,000)
Preferred Stock Dividends			(240)		(240)
Other		555			555
TOTAL					400,244
COMPREHENSIVE INCOME					
NET INCOME			58,950		58,950
TOTAL COMPREHENSIVE INCOME					58,950
DECEMBER 31, 2007	\$ 55,292	\$ 133,161	\$ 270,741	\$ -	\$ 459,194

See Notes to Consolidated Financial Statements.

**AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS**

ASSETS

**December 31, 2007 and 2006
(in thousands)**

	2007	2006
CURRENT ASSETS		
Cash and Cash Equivalents	\$ 101	\$ 779
Other Cash Deposits	192,725	104,203
Advances to Affiliates	180,926	394,004
Accounts Receivable:		
Customers	54,992	31,215
Affiliated Companies	6,848	8,613
Accrued Unbilled Revenues	32,056	10,093
Allowance for Uncollectible Accounts	(273)	(49)
Total Accounts Receivable	93,623	49,872
Materials and Supplies	27,624	28,347
Prepayments and Other	4,813	5,672
TOTAL	499,812	582,877
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	962,859	904,527
Distribution	1,670,120	1,579,498
Other	231,571	220,028
Construction Work in Progress	122,666	165,979
Total	2,987,216	2,870,032
Accumulated Depreciation and Amortization	667,124	630,239
TOTAL - NET	2,320,092	2,239,793
OTHER NONCURRENT ASSETS		
Regulatory Assets	167,991	193,111
Securitized Transition Assets	2,107,510	2,158,408
Deferred Charges and Other	94,592	105,067
TOTAL	2,370,093	2,456,586
Assets Held for Sale – Texas Generation Plant	-	44,475
TOTAL ASSETS	\$ 5,189,997	\$ 5,323,731

See Notes to Consolidated Financial Statements.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2007 and 2006

	2007	2006
CURRENT LIABILITIES	(in thousands)	
Accounts Payable:		
General	\$ 21,629	\$ 26,934
Affiliated Companies	20,872	21,234
Long-term Debt Due Within One Year – Nonaffiliated	143,419	78,227
Customer Deposits	55,740	18,742
Accrued Taxes	31,344	74,499
Accrued Interest	69,595	44,712
Other	50,450	34,762
TOTAL	393,049	299,110
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,794,134	2,937,387
Deferred Income Taxes	1,030,015	1,034,123
Regulatory Liabilities and Deferred Investment Tax Credits	454,528	598,027
Deferred Credits and Other	53,156	44,047
TOTAL	4,331,833	4,613,584
TOTAL LIABILITIES	4,724,882	4,912,694
Cumulative Preferred Stock Not Subject to Mandatory Redemption	5,921	5,921
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – \$25 Per Share:		
Authorized – 12,000,000 Shares		
Outstanding – 2,211,678 Shares	55,292	55,292
Paid-in Capital	133,161	132,606
Retained Earnings	270,741	217,218
TOTAL	459,194	405,116
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	\$ 5,189,997	\$ 5,323,731

See Notes to Consolidated Financial Statements.

AEP TEXAS CENTRAL COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2007, 2006 and 2005
(in thousands)

	<u>2007</u>	<u>2006</u>	<u>2005</u>
OPERATING ACTIVITIES			
Net Income (Loss)	\$ 58,950	\$ 41,569	\$ (173,779)
Adjustments to Reconcile Net Income to Net Cash Flows from (Used for)			
Operating Activities:			
Depreciation and Amortization	214,470	164,773	146,258
Deferred Income Taxes	(390)	24,200	(91,387)
Extraordinary Loss on Stranded Cost Recovery, Net of Tax	-	-	224,551
Carrying Costs on Stranded Cost Recovery	-	(69,080)	19,293
Allowance for Equity Funds Used During Construction	(3,232)	(2,688)	(1,003)
Mark-to-Market of Risk Management Contracts	-	5,426	4,275
Fuel Over/Under Recovery, Net	(163,516)	(12,424)	(34,328)
Change in Other Noncurrent Assets	(68,385)	(12,575)	(10,872)
Change in Other Noncurrent Liabilities	5,141	(60,394)	3,609
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(43,751)	209,034	(28,947)
Fuel, Materials and Supplies	358	(15,303)	(1,559)
Accounts Payable	1,244	(105,537)	6,797
Customer Deposits	36,998	8,084	4,512
Accrued Taxes, Net	(36,157)	19,933	(128,022)
Accrued Interest	22,989	12,215	(8,730)
Other Current Assets	2,125	18,999	(14,313)
Other Current Liabilities	15,405	(2,119)	11,378
Net Cash Flows from (Used for) Operating Activities	<u>42,249</u>	<u>224,113</u>	<u>(72,267)</u>
INVESTING ACTIVITIES			
Construction Expenditures	(221,898)	(270,330)	(178,628)
Change in Other Cash Deposits, Net	(66,972)	(37,407)	68,953
Change in Advances to Affiliates, Net	213,078	(394,004)	-
Purchases of Investment Securities	-	-	(154,364)
Sales of Investment Securities	-	-	149,804
Proceeds from Sale of Assets	116,292	9,380	315,318
Other	2	-	-
Net Cash Flows from (Used for) Investing Activities	<u>40,502</u>	<u>(692,361)</u>	<u>201,083</u>
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	5,264	1,715,285	316,901
Issuance of Long-term Debt – Affiliated	-	195,000	150,000
Change in Advances from Affiliates, Net	-	(82,080)	81,873
Retirement of Long-term Debt – Nonaffiliated	(84,557)	(427,900)	(526,897)
Retirement of Long-term Debt – Affiliated	-	(345,000)	-
Retirement of Cumulative Preferred Stock	-	(13)	-
Principal Payments for Capital Lease Obligations	(1,451)	(1,024)	(478)
Dividends Paid on Common Stock	(3,000)	(585,000)	(150,000)
Dividends Paid on Cumulative Preferred Stock	(240)	(241)	(241)
Other	555	-	-
Net Cash Flows from (Used for) Financing Activities	<u>(83,429)</u>	<u>469,027</u>	<u>(128,842)</u>
Net Increase (Decrease) in Cash and Cash Equivalents	(678)	779	(26)
Cash and Cash Equivalents at Beginning of Period	779	-	26
Cash and Cash Equivalents at End of Period	<u>\$ 101</u>	<u>\$ 779</u>	<u>\$ -</u>
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	\$ 133,967	\$ 105,896	\$ 104,701
Net Cash Paid (Received) for Income Taxes	52,159	(24,649)	235,697
Noncash Acquisitions Under Capital Leases	948	3,572	977
Construction Expenditures Included in Accounts Payable at December 31,	9,591	16,502	11,037

See Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Summary of Significant Accounting Policies
2. New Accounting Pronouncements and Extraordinary Item
3. Rate Matters
4. Effects of Regulation
5. Commitments, Guarantees and Contingencies
6. Company-wide Staffing and Budget Review
7. Dispositions and Assets Held for Sale
8. Benefit Plans
9. Business Segments
10. Derivatives, Hedging and Financial Instruments
11. Income Taxes
12. Leases
13. Financing Activities
14. Related Party Transactions
15. Property, Plant and Equipment
16. Unaudited Quarterly Financial Information

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

As a public utility, TCC engages in the transmission and distribution of electric power to 753,000 retail customers through REPs in its service territory in southern and central Texas. TCC consolidates AEP Texas Central Transition Funding LLC and AEP Texas Central Transition Funding II LLC, its wholly-owned subsidiaries.

Under the Texas Restructuring Legislation, TCC completed the final stage of exiting the generation business and ceased serving retail load. Based on corporate separation and generation divestiture, the nature of TCC's business is no longer compatible with its participation in the CSW Operating Agreement and the SIA since these agreements involve the coordinated planning and operation of power supply facilities. Accordingly, TCC sought and received FERC approval to be removed from those agreements. TCC's sharing of margins under the CSW Operating Agreement ceased on May 1, 2006. The sharing of margins with AEP East companies under the SIA ceased on April 1, 2006.

Prior to May 1, 2006, as a member of the CSW Operating Agreement, TCC was compensated for energy delivered to other members based upon its incremental cost plus a portion of the savings realized by the purchasing member that avoids the use of more costly alternatives. The revenues and costs for sales to neighboring utilities and power marketers made by AEPSC on behalf of the AEP West companies were generally shared among the members based upon the relative magnitude of energy each member provided to make such sales.

Prior to April 1, 2006, under the SIA, revenues and expenses from the sales to neighboring utilities, power marketers and other power and gas risk management activities were shared among AEP East companies and AEP West companies. Sharing in a calendar year was based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger of AEP and CSW. This resulted in an AEP East companies' and AEP West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year may also be based upon the relative generating capacity of the AEP East companies and AEP West companies in the event the pre-merger activity level was exceeded. The capacity-based allocation mechanism was triggered in July 2005, resulting in an allocation factor of approximately 70% and 30% for the AEP East companies and AEP West companies, respectively, for the remainder of the year.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

TCC is regulated by the FERC under the 2005 Public Utility Holding Company Act (2005 PUHCA) and by the PUCT. The PUCT approves the rates TCC charges and regulates the services and operations for a majority of TCC's transmission and distribution energy delivery services. The FERC regulates certain, mostly affiliated, transactions under the 2005 PUHCA.

Generally, the FERC also regulates, on a cost basis, wholesale transmission service and rates. TCC's wholesale transmission rates are also regulated on a cost basis by the PUCT. TCC offers no retail transmission services.

In addition, the FERC regulates the CSW Operating Agreement, the Transmission Coordination Agreement, and SIA, all of which allocate shared system costs and revenues to the utility subsidiaries that are parties to the agreements, including TCC. The sharing of margins with the AEP East companies under the SIA ceased on April 1, 2006.

The PUCT regulates all of TCC's public utility operations where transmission and distribution rates are regulated on a cost-basis and unbundled by function. TCC has no Texas jurisdictional retail generation/power supply operations. See Note 3 for further details of Texas's restructuring legislation and its effects on TCC in Texas.

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

Both the FERC and the PUCT are permitted to review and audit the books and records of TCC.

Principles of Consolidation

TCC's consolidated financial statements include TCC and its wholly-owned subsidiaries. Intercompany items are eliminated in consolidation.

Accounting for the Effects of Cost-Based Regulation

As a cost-based rate-regulated electric transmission and distribution company, TCC's financial statements reflect the actions of regulators that result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with SFAS 71, regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues and income with its passage to customers through the reduction of regulated revenues. Due to the commencement of legislatively required restructuring and a transition to customer choice and market-based rates, TCC discontinued the application of SFAS 71, regulatory accounting, for the generation portion of its business in September 1999. SFAS 101, "Regulated Enterprises – Accounting for the Discontinuance of Application of FASB Statement No. 71" requires the recognition of an impairment of stranded regulatory assets and stranded plants costs if they are not recoverable in regulated rates. In addition, an enterprise is required to eliminate from its balance sheet the effects of any actions of regulators that had been recognized as regulatory assets and regulatory liabilities pursuant to SFAS 71. Such impairments and adjustments arising from the discontinuance or reapplication of SFAS 71 are classified by SFAS 101 as an extraordinary item. TCC recorded extraordinary impairment losses related to its regulatory assets and plant costs in 2005 resulting from the discontinuance of cost-based regulation of its generation businesses without full recovery of the resultant stranded costs.

Use of Estimates

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

Property, Plant and Equipment and Equity Investments

Electric utility property, plant and equipment are stated at original purchase cost. Additions, major replacements and betterments are added to the plant accounts. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for cost-based rate-regulated operations under the group composite method of depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. Under the group composite method of depreciation, continuous interim routine

replacements of items such as boiler tubes, pumps, motors, etc. result in the original cost, less salvage, being charged to accumulated depreciation. The depreciation rates that are established for the generating plants take into account the past history of interim capital replacements and the amount of salvage received. These rates and the related lives are subject to periodic review. Removal costs are charged to regulatory liabilities. The costs of labor, materials and overhead incurred to operate and maintain the plants are included in operating expenses.

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

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

Allowance for Funds Used During Construction (AFUDC)

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of domestic regulated electric utility plant.

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Other Cash Deposits, Accounts Receivable and Accounts Payable approximate fair value because of the short-term maturity of these instruments.

Cash and Cash Equivalents

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

Other Cash Deposits

Other Cash Deposits include funds held by trustees primarily for the payment of debt and to secure the payments of the REPs.

Inventory

Materials and supplies inventories are carried at average cost.

Accounts Receivable

Customer accounts receivable primarily include receivables from wholesale and retail energy customers and customer receivables primarily related to other revenue-generating activities.

Revenue is recognized from electric power sales or delivery when power is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, TCC accrues and recognizes, as Accrued Unbilled Revenues, an estimate of the revenues for energy delivered since the last billing.

Concentrations of Credit Risk and Significant Customers

TCC has significant customers which on a combined basis account for the following percentages of total Operating Revenues for the periods ended and Accounts Receivable – Customers as of December 31:

	<u>2007</u>	<u>2006</u>	<u>2005</u>
TCC – Centrica and ERCOT (2006 and 2005 only)			
Percentage of Operating Revenues	23%	29%	29%
Percentage of Accounts Receivable - Customers	29%	7%	7%

TCC monitors credit levels and the financial condition of their customers on a continuing basis to minimize credit risk. Management believes adequate provision for credit loss has been made in the accompanying financial statements.

Revenue Recognition

Regulatory Accounting

The financial statements for cost-based rate-regulated operations reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period and by matching income with its passage to customers in cost-based regulated rates.

When regulatory assets are probable of recovery through regulated rates, TCC records them as assets on the balance sheet. TCC tests for probability of recovery whenever new events occur, for example, issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, TCC writes off that regulatory asset as a charge against earnings.

Traditional Electricity Supply and Delivery Activities

TCC recognizes revenues from wholesale electricity supply sales and electricity transmission and distribution delivery services. TCC recognizes the revenues in the financial statements upon delivery of the energy to the customer and includes unbilled as well as billed amounts. TCC records expenses upon receipt of purchased electricity and when expenses are incurred. TCC records third party purchases as non-trading and these purchases are accounted for on a gross basis as Purchased Electricity for Resale in the Consolidated Statements of Operations.

Energy Marketing and Risk Management Activities

Prior to the FERC approved removal from the SIA and CSW Operating Agreement, effective April 1, and May 1, 2006 respectively, TCC engaged in wholesale electricity, natural gas, coal and emission allowances marketing and risk management activities focused on wholesale markets where the AEP System owns assets. TCC's activities included the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts which included exchange traded futures and options, and over-the-counter options and swaps. TCC engaged in certain energy marketing and risk management transactions with RTOs.

TCC recognized revenues and expenses from wholesale marketing and risk management transactions that were not derivatives upon delivery of the commodity. TCC used MTM accounting for wholesale marketing and risk management transactions that were derivatives unless the derivative was designated in a qualifying cash flow hedge relationship or as a normal purchase or sale. TCC recorded the unrealized and realized gains and losses on wholesale marketing and risk management transactions accounted for using MTM in Revenues in the Consolidated Statements of Operations on a net basis.

Certain qualifying wholesale marketing and risk management derivative transactions were designated as hedges of future cash flows as a result of forecasted transactions (cash flow hedge). TCC initially recorded the effective portion of the cash flow hedge's gain or loss as a component of Accumulated Other Comprehensive Income (Loss). When the forecasted transaction was realized and affected earnings, TCC subsequently reclassified the gain or loss on the hedge from Accumulated Other Comprehensive Income into revenues or expenses on its Consolidated Statements of Operations, within the same financial statement line item as the forecasted transaction. The ineffective portion of the gain or loss was recognized in revenues in the financial statements immediately.

Construction Projects for Outside Parties

TCC engages in construction projects for outside parties that are accounted for on the percentage-of-completion method of revenue recognition. This method recognizes revenue, including the related margin, as project costs are incurred. TCC includes such revenue and related expenses in Other Revenue and Other Operation Expenses, respectively, in the financial statements. TCC includes contractually billable expenses not yet billed in Current Assets in the financial statements.

Maintenance

Maintenance costs are expensed as incurred. If it becomes probable that TCC will recover specifically-incurred costs through future rates, a regulatory asset is established to match the expensing of those maintenance costs with its recovery in cost-based regulated revenues.

Income Taxes and Investment Tax Credits

TCC uses the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence.

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

Investment tax credits are accounted for under the deferral basis and are being amortized over the life of the plant investment.

TCC accounts for uncertain tax positions in accordance with FIN 48. Effective with the adoption of FIN 48, TCC classifies interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classifies penalties as Other Operation.

Excise Taxes

As an agent for some state and local governments, TCC collects from customers certain excise taxes levied by those state or local governments on customers. TCC does not record these taxes as revenue or expense.

Debt and Preferred Stock

Gains and losses from the reacquisition of debt used to finance regulated electric utility plants are deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If the reacquired debt associated with the regulated business is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates.

Debt discount or premium and debt issuance expenses are deferred and amortized generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations. The net amortization expense is included in Interest Expense.

The excess of par value over costs of preferred stock reacquired is credited to paid-in capital and reclassified to retained earnings upon the redemption of the entire preferred stock series. The excess of par value over the costs of reacquired preferred stock for nonregulated operations is credited to retained earnings upon reacquisition.

Comprehensive Income (Loss)

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

Earnings Per Share (EPS)

TCC is owned by a wholly-owned subsidiary of AEP, therefore, TCC is not required to report EPS.

Reclassifications

Certain prior period financial statement items have been reclassified to conform to current period presentation. These revisions had no impact on TCC's previously reported results of operations or changes in shareholders' equity.

2. NEW ACCOUNTING PRONOUNCEMENTS AND EXTRAORDINARY ITEM

NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of exposure drafts or final pronouncements, management thoroughly reviews the new accounting literature to determine the relevance, if any, to TCC's business. The following represents a summary of final pronouncements that management has determined relate to TCC's operations.

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

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

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

SFAS 157 "Fair Value Measurements" (SFAS 157)

In September 2006, the FASB issued SFAS 157, enhancing existing guidance for fair value measurement of assets and liabilities and instruments measured at fair value that are classified in shareholders' equity. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures. It emphasizes that fair value is market-based with the highest measurement hierarchy level being market prices in active markets. The standard requires fair value measurements be disclosed by hierarchy level, an entity include its own credit standing in the measurement of its liabilities and modifies the transaction price presumption. The standard also nullifies the

consensus reached in EITF Issue No. 02-3 “Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities” (EITF 02-3) that prohibited the recognition of trading gains or losses at the inception of a derivative contract, unless the fair value of such derivative is supported by observable market data.

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

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

TCC partially adopted SFAS 157 effective January 1, 2008. TCC will adopt SFAS 157 effective January 1, 2009 for items within the scope of FSP FAS 157-2. The provisions of SFAS 157 are applied prospectively, except for a) changes in fair value measurements of existing derivative financial instruments measured initially using the transaction price under EITF 02-3, b) existing hybrid financial instruments measured initially at fair value using the transaction price and c) blockage discount factors. Although the statement is applied prospectively upon adoption, in accordance with the provisions of SFAS 157 related to EITF 02-3, amounts for transition adjustment are recorded to beginning retained earnings. The consideration of AEP’s own credit risk when measuring the fair value of liabilities, including derivatives, impacts fair value measurements upon adoption. The adoption of this standard had no impact on TCC’s financial statements.

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

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

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

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

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

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

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

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

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

In June 2007, the FASB ratified the EITF consensus on the treatment of income tax benefits of dividends on employee share-based compensation. The issue is how a company should recognize the income tax benefit received on dividends that are paid to employees holding equity-classified nonvested shares, equity-classified nonvested share units or equity-classified outstanding share options and charged to retained earnings under SFAS 123R, “Share-Based Payments.” Under EITF 06-11, a realized income tax benefit from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for equity-classified nonvested equity shares, nonvested equity share units and outstanding equity share options should be recognized as an increase to additional paid-in capital.

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

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

In July 2006, the FASB issued FASB Interpretation No. 48 “Accounting for Uncertainty in Income Taxes” and in May 2007, the FASB issued FASB Staff Position FIN 48-1 “Definition of *Settlement* in FASB Interpretation No. 48.” FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise’s financial statements by prescribing a recognition threshold (whether a tax position is more likely than not to be sustained) without which, the benefit of that position is not recognized in the financial statements. It requires a measurement determination for recognized tax positions based on the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition.

FIN 48 requires that the cumulative effect of applying this interpretation be reported and disclosed as an adjustment to the opening balance of retained earnings for that fiscal year and presented separately. TCC adopted FIN 48 effective January 1, 2007. The impact of this interpretation was an unfavorable adjustment to retained earnings of \$2.2 million.

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

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

TCC adopted FIN 39-1 effective January 1, 2008. This standard changed the method of netting certain balance sheet amounts. It requires retrospective application as a change in accounting principle for all periods presented. It had no impact on TCC.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by the FASB, management cannot determine the impact on the reporting of operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, liabilities and equity, derivatives disclosures, emission allowances, leases, insurance, subsequent events and related tax impacts. Management also expects to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on future results of operations and financial position.

EXTRAORDINARY ITEM

Texas Stranded Cost Recovery

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

3. RATE MATTERS

TCC is involved in rate and regulatory proceedings at the FERC and the PUCT. This note is a discussion of rate matters and industry restructuring related proceedings that could have a material effect on the results of operations and cash flows.

TEXAS RESTRUCTURING

Texas Restructuring Appeals

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

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

Municipal customers and other intervenors also appealed the PUCT true-up and related orders seeking to further reduce TCC's true-up recoveries. In March 2007, the Texas District Court judge hearing the appeal of the true-up order affirmed the PUCT's April 2006 final true-up order for TCC with two significant exceptions. The judge determined that the PUCT erred by applying an invalid rule to determine the carrying cost rate for the true-up of

stranded costs. However, the District Court did not rule that the carrying cost rate was inappropriate. If the PUCT reevaluates the carrying cost rate on remand and reduces the rate, it could result in a material adverse change to TCC's recoverable carrying costs, results of operations, cash flows and financial condition.

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

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

Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes

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

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

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

Deferred Fuel

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

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

Excess Earnings

In 2005, a Texas appellate court issued a decision finding that a PUCT order requiring TCC to refund to the REPs excess earnings prior to and outside of the true-up process was unlawful under the Texas Restructuring Legislation. From 2002 to 2005, TCC refunded \$55 million of excess earnings, including interest, under the overturned PUCT order. On remand, the PUCT must determine how to implement the Court of Appeals decision given that the unauthorized refunds were made in lieu of reducing stranded cost recoveries in the True-up Proceeding. As a result, TCC's stranded cost recovery, which is currently on appeal, may be affected by a PUCT remedy. In December 2007, the Texas Court of Appeals issued a decision in CenterPoint's, a nonaffiliated Texas utility, true-up proceeding determining that even though excess earnings had been previously refunded to the affiliated REP, CenterPoint still must reduce stranded cost recoveries in its true-up proceeding. In 2005, TCC reflected the obligation to refund excess earnings to customers through the true-up process and recorded a regulatory asset for the expected refund to be received from the REPs. However, certain parties have taken positions that, if adopted, could result in TCC being required to refund additional amounts of excess earnings or interest through the true-up process without receiving a refund from the REPs. If this were to occur it would have an adverse effect on future results of operations and cash flows. AEP sold its affiliate REPs in December 2002. While AEP owned the affiliate REP, TCC refunded \$11 million of excess earnings to the affiliate REP. Management cannot predict the outcome of these matters.

Oklaunion Refund

In 2005, the PUCT approved TCC's request to file its True-up Proceeding before it had completed the sale of its share of the Oklaunion power plant. TCC agreed to provide customers the net economic benefit related to its continued ownership of the Oklaunion power plant until the sale closed and to reduce stranded costs if the Oklaunion power plant sales price increased. In June 2007, after the closing, TCC filed with the PUCT reporting no change in the sales price and proposing to refund the net economic benefit from the operation of the Oklaunion power plant. In February 2008, TCC reached a settlement agreement with a majority of the parties to the proceeding to refund a net economic benefit of \$7 million. Management expects PUCT approval of agreement by the second quarter of 2008 which will not have a material effect on results of operations or cash flows.

OTHER TEXAS RATE MATTERS

Energy Delivery Base Rate Filing

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

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

4. EFFECTS OF REGULATION

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	<u>December 31,</u>		
	<u>2007</u>	<u>2006</u>	<u>Notes</u>
	(in thousands)		
Regulatory Assets:			
SFAS 158 Regulatory Asset (Note 8)	\$ 89,377	\$ 105,108	(a) (e)
Transition Regulatory Assets	45,819	55,370	(c) (g)
Unamortized Loss on Reacquired Debt	20,523	23,868	(b) (h)
Other	12,272	8,765	(c) (e)
Total Noncurrent Regulatory Assets	<u>\$ 167,991</u>	<u>\$ 193,111</u>	
Regulatory Liabilities:			
Asset Removal Costs	\$ 246,247	\$ 246,115	(d)
Deferred Investment Tax Credits	103,663	104,264	(a) (f)
SFAS 109 Regulatory Liability, Net (Note 11)	17,266	18,453	(b) (e)
CTC Refund	-	155,030	(b)
Other	87,352	74,165	(c) (e)
Total Noncurrent Regulatory Liabilities	<u>\$ 454,528</u>	<u>\$ 598,027</u>	

- (a) Amount does not earn a return.
- (b) Amount effectively earns a return.
- (c) Includes items both earning and not earning a return.
- (d) The liability for removal costs, which reduces rate base and the resultant return, will be discharged as removal costs are incurred.
- (e) Recovery/refund period – various periods.
- (f) Recovery/refund period – up to 55 years.
- (g) Recovery/refund period – up to 8 years.
- (h) Recovery/refund period – up to 29 years.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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

Insurance and Potential Losses

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

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could have a material adverse effect on results of operations, cash flows and financial condition.

COMMITMENTS

TCC has substantial construction commitments to support its operations and environmental investments. In managing the overall construction program and in the normal course of business, TCC contractually commits to third-party construction vendors for certain material purchases and other construction services. Aggregate construction expenditures for 2008 through 2010 are estimated at approximately \$704 million. The amounts for 2008, 2009 and 2010 are \$208.2 million, \$251.2 million and \$244.6 million, respectively. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital.

TCC purchases materials, supplies, services and property, plant and equipment under contract as part of its normal course of business. Certain supply contracts contain penalty provisions for early termination. TCC does not expect to incur penalty payments under these provisions that would materially affect results of operations, cash flows or financial condition.

GUARANTEES

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

Indemnifications and Other Guarantees

Contracts

TCC enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. Prior to December 31, 2007, TCC entered into sale agreements including indemnifications with a maximum exposure of \$26 million related to the sale price of generation assets and ETT. See "Texas Plants – Oklaunion Power Station" and "Electric Transmission Texas LLC (ETT)" sections of Note 7. There are no material liabilities recorded for any indemnifications.

Master Operating Lease

TCC leases certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, TCC has committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. Historically, at the end of the lease term the fair market value has been in excess of the unamortized balance. Assuming the fair market value of the equipment is zero at the end of the lease term, the maximum potential loss for these lease agreements was approximately \$6 million as of December 31, 2007.

CONTINGENCIES

Carbon Dioxide (CO₂) Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO₂ emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The dismissal of the lawsuit was appealed to the Second Circuit Court of Appeals. Briefing and oral argument have concluded. In April 2007, the U.S. Supreme Court issued a decision holding that the Federal EPA has authority to regulate emissions of CO₂ and other greenhouse

gases under the CAA, which may impact the Second Circuit's analysis of these issues. The Second Circuit requested supplemental briefs addressing the impact of the Supreme Court's decision on this case. Management believes the actions are without merit and intends to defend against the claims.

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

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

Superfund addresses clean-up of hazardous substances that have been released to the environment. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. At December 31, 2007, TCC has been named potentially liable at one site under state law. In the instance where TCC has been named a defendant, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on results of operations.

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

Coal Transportation Dispute

PSO, TCC, TNC, the Oklahoma Municipal Power Authority and the Public Utilities Board of the City of Brownsville, Texas, as joint owners of a generating station, disputed transportation costs for coal received between July 2000 and the present time. The joint plant remitted less than the amount billed. In September 2007, the Surface Transportation Board ruled that the disputed rates were not unreasonable under the standalone cost rate test. The joint owners filed a Petition for Reconsideration. Based upon this ruling, PSO, as operator of the plant, adjusted the provision recorded in prior periods. After mitigation by certain contractual rights, the adjustment immaterially affected income for TCC's ownership share.

Claims by the City of Brownsville, Texas Against TCC

In July 2007, the City of Brownsville, Texas filed an original petition in litigation pending in the District Court of Dallas County, Texas. The petition seeks recovery against TCC based on allegations of breach of contract, breach of fiduciary duty, unjust enrichment, constructive trust, conversion, breach of the Texas theft liability act and fraud allegedly occurring in connection with a transaction in which Brownsville purchased TCC's interest in the Oklahoma electric generating station. In 2007 and early 2008, the court heard various motions for partial summary judgment. No date for a ruling is indicated by the court. Management believes that the claims are without merit and intends to defend against them vigorously.

FERC Long-term Contracts

In 2002, the FERC held a hearing related to a complaint filed by Nevada Power Company and Sierra Pacific Power Company (the Nevada utilities). The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were "high-priced." The complaint alleged that TCC and certain other AEP subsidiaries sold power at unjust and unreasonable prices because the market for power was allegedly dysfunctional at the time such contracts were executed. In 2003, the FERC rejected the complaint. In December 2006, the U.S. Court of Appeals for the Ninth Circuit reversed the FERC order and remanded the case to the FERC for further proceedings. That decision was appealed and the U.S. Supreme Court decided that it will review the Ninth Circuit's decision in 2008. Management is unable to predict the outcome of these proceedings or their impact on future results of operations and cash flows. Management asserted claims against certain companies that sold power to TCC and certain other AEP subsidiaries, which was resold to the Nevada utilities, seeking to recover a portion of any amounts that may be owed to the Nevada utilities.

6. COMPANY-WIDE STAFFING AND BUDGET REVIEW

TCC recorded \$4.3 million of severance benefits expense in 2005 (primarily in Other Operation and Maintenance) resulting from a company-wide staffing and budget review, including the allocation of approximately \$19.2 million of severance benefits expense associated with AEPSC employees. Payments and accrual adjustments recorded during 2006 were immaterial and were settled by June 30, 2006.

7. DISPOSITIONS AND ASSETS HELD FOR SALE

2007

Electric Transmission Texas LLC (ETT)

In December 2007, TCC contributed \$70 million of transmission facilities to ETT, a newly-formed affiliated entity which will own and operate transmission assets in ERCOT. Through a series of transactions, TCC received a cash distribution from ETT of \$42 million and sold a 50% interest, at net book value, for \$14 million to MidAmerican Energy Holdings Company. TCC then distributed its remaining 50% interest (book value of \$14 million) in ETT to, its parent, AEP Utilities, Inc., the holding company for AEP's ERCOT investments.

Texas Plants – Oklaunion Power Station

In February 2007, TCC sold its 7.81% share of Oklaunion Power Station to the Public Utilities Board of the City of Brownsville for \$43 million plus adjustments. The sale did not have a material effect on TCC's results of operations. See "Claims by the City of Brownsville, Texas Against TCC" section of Note 5.

TCC's assets related to the Oklaunion Power Station were classified in Assets Held for Sale – Texas Generation Plant on TCC's Consolidated Balance Sheet at December 31, 2006. The plant did not meet the "component-of-an-entity" criteria because the plant did not have cash flows that could be clearly distinguished operationally and because the plant did not operate individually, but rather as a part of the AEP System.

Assets Held for Sale were as follows:

<u>Texas Plants (TCC)</u>	December 31,	
	2007	2006
	(in millions)	
Assets:		
Other Current Assets	\$ -	\$ 1
Property, Plant and Equipment, Net	-	43
Total Assets Held for Sale – Texas Generation Plant	\$ -	\$ 44

2006

None

2005

Texas Plants – South Texas Project

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

With the sale of STP, TCC transferred the nuclear decommissioning liability and the related trust assets to the purchaser. Proceeds from sales of TCC's nuclear trust fund investments were \$150 million in 2005. Purchases of TCC's nuclear trust fund investments were \$154 million in 2005. Gross realized gains and gross realized losses from the sales of TCC's nuclear trust fund investments were \$9 million and \$2 million, respectively, in 2005.

8. BENEFIT PLANS

TCC participates in AEP sponsored qualified pension plans and nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. TCC participates in other postretirement benefit plans sponsored by AEP to provide medical and death benefits for retired employees.

TCC adopted SFAS 158 as of December 31, 2006. It requires employers to fully recognize the obligations associated with defined benefit pension plans and OPEB plans, which include retiree healthcare, in their balance sheets. Previous standards required an employer to disclose the complete funded status of its plan only in the notes to the financial statements and provided that an employer delay recognition of certain changes in plan assets and obligations that affected the costs of providing benefits resulting in an asset or liability that often differed from the plan's funded status. SFAS 158 requires a defined benefit pension or postretirement plan sponsor to (a) recognize in its statement of financial position an asset for a plan's overfunded status or a liability for the plan's underfunded status, (b) measure the plan's assets and obligations that determine its funded status as of the end of the employer's fiscal year and (c) recognize, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year but are not recognized as a component of net periodic benefit cost pursuant to previous standards. It also requires an employer to disclose additional information on how delayed recognition of certain changes in the funded status of a defined benefit pension or OPEB plan affects net periodic benefit costs for the next fiscal year. TCC recorded a SFAS 71 regulatory asset of \$105.1 million for qualifying SFAS 158 costs of regulated operations that for ratemaking purposes will be deferred for future recovery. The effect of this standard on the 2006 financial statements was a pretax AOCI adjustment that was fully offset by a SFAS 71 regulatory asset.

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

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

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

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

Amounts Recognized on AEP's Balance Sheets as of December 31, 2007 and 2006

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

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

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

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

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

Pension and Other Postretirement Plans' Assets

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

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

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

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

AEP's investment strategy for the employee benefit trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the interest rate sensitivity of the plans' assets relative to the plans' liabilities. To minimize investment risk, AEP's employee benefit trust funds are broadly diversified among

classes of assets, investment strategies and investment managers. AEP regularly reviews the actual asset allocation and periodically rebalances the investments to AEP's targeted allocation when considered appropriate. AEP's investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. The investment policies prohibit investment in AEP securities, with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies.

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

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

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

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

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

Actuarial Assumptions for Benefit Obligations

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

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

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

N/A = Not Applicable

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

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

Estimated Future Benefit Payments and Contributions

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

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

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

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

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

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

Components of Net Periodic Benefit Cost

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

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

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

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

The following table provides TCC's net periodic benefit cost (credit) for the plans for the years ended December 31, 2007, 2006 and 2005:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2007	2006	2005	2007	2006	2005
	(in thousands)					
Benefit Cost (Credit)	\$ 404	\$ 3,091	\$ (880)	\$ 6,298	\$ 6,787	\$ 7,521

Actuarial Assumptions for Net Periodic Benefit Costs

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

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

N/A = Not Applicable

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

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

<u>Health Care Trend Rates</u>	<u>2007</u>	<u>2006</u>
Initial	7.5 %	8.0 %
Ultimate	5.0 %	5.0 %
Year Ultimate Reached	2012	2009

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

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

AEP Savings Plan

TCC participates in an AEP sponsored defined contribution retirement savings plans for substantially all employees. These plans offer participants an opportunity to contribute a portion of their pay, include features under Section 401(k) of the Internal Revenue Code and provide for company matching contributions. The matching contributions to the plan are 75% of the first 6% of eligible compensation contributed by the employee. The cost for contributions to these plans totaled \$3.3 million in 2007, \$3.1 million in 2006 and \$2.5 million in 2005.

9. BUSINESS SEGMENTS

TCC has one reportable segment, an integrated electricity transmission and distribution business. TCC's other activities are insignificant.

10. DERIVATIVES, HEDGING AND FINANCIAL INSTRUMENTS

DERIVATIVES AND HEDGING

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

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

TCC's accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), TCC initially reports the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) until the period the hedged item affects earnings. TCC recognizes any hedge ineffectiveness in earnings immediately during the period of change.

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

Cash Flow Hedging Strategies

Prior to TCC's FERC approved removal from the SIA and CSW Operating Agreement, TCC entered into, and designated as cash flow hedges, certain derivative transactions for the purchase and sale of electricity and natural gas in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. At various times during 2006 and 2005, TCC designated cash flow hedge relationships using these commodities. Management closely monitored the potential impacts of commodity price changes, and where appropriate, entered into derivative transactions to protect margins for a portion of future electricity sales and fuel purchases. Realized gains and losses on these derivatives designated as cash flow hedges were included in Revenues or fuel expense, depending on the specific nature of the risk being hedged. TCC did not hedge all variable price risk exposure related to energy commodities. At various times during 2006 and 2005, TCC recognized immaterial amounts in earnings related to hedge ineffectiveness.

The following table represents the activity in Accumulated Other Comprehensive Income (Loss) for derivative contracts that qualify as cash flow hedges for the years 2005, 2006 and 2007:

	(in thousands)
Balance at December 31, 2004	\$ 657
Effective portion of changes in fair value	(635)
Reclasses from AOCI to Net Income	(246)
Balance at December 31, 2005	(224)
Effective portion of changes in fair value	-
Impact Due to Changes in SIA	218
Reclasses from AOCI to Net Income	6
Balance at December 31, 2006	\$ -
Effective portion of changes in fair value	-
Reclasses from AOCI to Net Income	-
Balance at December 31, 2007	\$ -

FINANCIAL INSTRUMENTS

The fair values of Long-term Debt are based on quoted market prices for the same or similar issues and the current interest rates offered for instruments with similar maturities. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange. The book values and fair values of TCC's significant financial instruments at December 31, 2007 and 2006 are summarized in the following table.

	December 31,			
	2007		2006	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	\$ 2,937,553	\$ 2,922,875	\$ 3,015,614	\$ 3,040,398

11. INCOME TAXES

The details of income taxes before extraordinary loss as reported are as follows:

	Years Ended December 31,		
	<u>2007</u>	<u>2006</u>	<u>2005</u>
	(in thousands)		
Income Tax Expense (Credit):			
Current	\$ 20,004	\$ (680)	\$ 106,437
Deferred	(390)	24,200	(91,387)
Deferred Investment Tax Credits	(601)	(870)	(2,609)
Total Income Tax	<u>\$ 19,013</u>	<u>\$ 22,650</u>	<u>\$ 12,441</u>

Shown below is a reconciliation of the difference between the amount of federal income taxes computed by multiplying book income before income taxes by the federal statutory rate and the amount of income taxes reported.

	Years Ended December 31,		
	<u>2007</u>	<u>2006</u>	<u>2005</u>
	(in thousands)		
Net Income (Loss)	\$ 58,950	\$ 41,569	\$ (173,779)
Extraordinary Loss	-	-	224,551
Income Taxes	19,013	22,650	12,441
Pretax Income	<u>\$ 77,963</u>	<u>\$ 64,219</u>	<u>\$ 63,213</u>
Income Tax on Pretax Income at Statutory Rate (35%)	\$ 27,287	\$ 22,477	\$ 22,125
Increase (Decrease) in Income Tax resulting from the following items:			
Depreciation	(457)	(453)	(519)
Tax Adjustments	(7,350)	(677)	(2,712)
Investment Tax Credits, Net	(601)	(870)	(2,609)
State and Local Income Taxes	1,974	3,782	300
Other	(1,840)	(1,609)	(4,144)(a)
Total Income Taxes	<u>\$ 19,013</u>	<u>\$ 22,650</u>	<u>\$ 12,441</u>
Effective Income Tax Rate	24.4%	35.3%	19.7%

(a) Includes \$(3,900) of consolidated tax savings from Parent.

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

	December 31,	
	<u>2007</u>	<u>2006</u>
	(in thousands)	
Deferred Tax Assets	\$ 159,203	\$ 235,109
Deferred Tax Liabilities	(1,187,481)	(1,269,232)
Net Deferred Tax Liabilities	<u>\$ (1,028,278)</u>	<u>\$ (1,034,123)</u>
Property Related Temporary Differences	\$ (251,246)	\$ (251,645)
Amounts Due From Customers For Future Federal Income Taxes	6,062	6,477
Deferred State Income Taxes	(1,466)	(2,248)
Transition Regulatory Assets	19,239	19,239
Accrued Nuclear Decommissioning Expense	(928)	(928)
Deferred Income Taxes on Other Comprehensive Loss	-	-
Deferred Fuel and Purchased Power	(25,456)	31,774
Accrued Pensions	(20,401)	(15,494)
Provision for Refund	9,193	50
Regulatory Assets	20,376	(15,795)
Securitized Transition Assets	(806,141)	(809,065)
All Other, Net	22,490	3,512
Net Deferred Tax Liabilities	<u>\$ (1,028,278)</u>	<u>\$ (1,034,123)</u>

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

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

TCC, along with other AEP Subsidiaries, files income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns and TCC and other AEP Subsidiaries are currently under examination in several state and local jurisdictions. Management believes that TCC and other AEP Subsidiaries have filed tax returns with positions that may be challenged by these tax authorities. However, management does not believe that the ultimate resolution of these audits will materially impact results of operations. With few exceptions, TCC is no longer subject to state or local income tax examinations by tax authorities for years before 2000.

Prior to the adoption of FIN 48, TCC recorded interest and penalty expense related to uncertain tax positions in tax expense accounts. With the adoption of FIN 48, TCC began recognizing interest accruals related to uncertain tax positions in interest income or expense as applicable, and penalties in Other Operation. In 2007, TCC reported \$600 thousand of interest expense. TCC had approximately \$2.4 million and \$4.6 million for the payment of interest and penalties accrued at December 31, 2007 and 2006, respectively.

As a result of the implementation of FIN 48 on January 1, 2007, TCC recognized a \$2.2 million increase in the liabilities for unrecognized tax benefits, as well as related interest expense and penalties, which was accounted for as a reduction to the January 1, 2007 balance of retained earnings.

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

	(in millions)
Balance at January 1, 2007	\$ 20.7
Increase - Tax Positions Taken During a Prior Period	0.2
Decrease - Tax Positions Taken During a Prior Period	(3.2)
Increase - Tax Positions Taken During the Current Year	0.5
Decrease - Settlements with Taxing Authorities	(0.2)
Decrease - Lapse of the Applicable Statute of Limitations	<u>-</u>
Balance at December 31, 2007	<u><u>\$ 18.0</u></u>

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is \$9.4 million. Management believes there will be no significant net increase or decrease in unrecognized tax benefits within 12 months of the reporting date.

Federal Tax Legislation

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

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

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

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

State Tax Legislation

On June 30, 2005, the Governor of Ohio signed Ohio House Bill 66 into law enacting sweeping tax changes impacting all companies doing business in Ohio. Most of the significant tax changes will be phased in over a five-year period, while some of the less significant changes became fully effective July 1, 2005. Changes to the Ohio franchise tax, nonutility property taxes and the new commercial activity tax are subject to phase-in. The Ohio franchise tax will fully phase-out over a five-year period beginning with a 20% reduction in state franchise tax for taxable income accrued during 2005. In 2005, TCC reversed \$1.1 million of SFAS 109 Regulatory Assets, \$365 thousand of state income tax expense and \$1.5 million of deferred state income tax liabilities that are not expected to reverse during the phase-out.

The new legislation also imposes a new commercial activity tax at a fully phased-in rate of 0.26% on all Ohio gross receipts. The new tax is being phased-in over a five-year period that began July 1, 2005 at 23% of the full 0.26% rate.

In the second quarter of 2006, the Texas state legislature replaced the existing franchise/income tax with a gross margin tax at a 1% rate for electric utilities. Overall, the new law reduces Texas income tax rates and is effective January 1, 2007. The new gross margin tax is income-based for purposes of the application of SFAS 109 "Accounting for Income Taxes." Based on the new law, management reviewed deferred tax liabilities with consideration given to the rate changes and changes to the allowed deductible items with temporary differences. As a result, in the second quarter of 2006 TCC recorded a \$36.3 million decrease in SFAS 109 Regulatory Assets and deferred state income tax liabilities.

12. LEASES

Leases of property, plant and equipment are for periods up to 10 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. The components of rental costs are as follows:

Lease Rental Costs	Years Ended December 31,		
	2007	2006	2005
		(in thousands)	
Net Lease Expense on Operating Leases	\$ 6,759	\$ 6,091	\$ 5,594
Amortization of Capital Leases	1,453	1,024	478
Interest on Capital Leases	267	223	60
Total Lease Rental Costs	\$ 8,479	\$ 7,338	\$ 6,132

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

	December 31,	
	2007	2006
	(in thousands)	
Property, Plant and Equipment Under Capital Leases		
Total Property, Plant and Equipment Under Capital Leases – Other	\$ 5,981	\$ 5,480
Accumulated Amortization	2,409	1,306
Net Property, Plant and Equipment Under Capital Leases	\$ 3,572	\$ 4,174
Obligations Under Capital Leases		
Noncurrent Liability	\$ 2,021	\$ 2,739
Liability Due Within One Year	1,551	1,358
Total Obligations Under Capital Leases	\$ 3,572	\$ 4,097

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

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
2008	\$ 1,711	\$ 6,508
2009	1,240	5,788
2010	593	5,285
2011	228	3,070
2012	73	1,900
Later Years	11	3,566
Total Future Minimum Lease Payments	\$ 3,856	\$ 26,117
Less Estimated Interest Element	284	
Estimated Present Value of Future Minimum Lease Payments	\$ 3,572	

13. FINANCING ACTIVITIES

Preferred Stock

Par Value	Authorized Shares	Shares Outstanding at December 31, 2007	Call Price at December 31, 2007 (a)	Series	Redemption	December 31,	
						2007	2006
						(in thousands)	
\$ 100	(b)	41,912	\$ 105.75	4.00%	Any time	\$ 4,191	\$ 4,191
100	(b)	17,301	103.75	4.20%	Any time	1,730	1,730

(a) The cumulative preferred stock is callable at the price indicated plus accrued dividends.

(b) TCC has 3,035,000 authorized shares in total.

Series	Number of Shares Redeemed for the Year Ended December 31,		
	2007	2006	2005
4.00%	-	10	-
4.20%	-	175	-

Long-term Debt

There are certain limitations on establishing liens against TCC's assets under its indentures. None of the long-term debt obligations of TCC have been guaranteed or secured by AEP or any of its affiliates.

The following details long-term debt outstanding as of December 31, 2007 and 2006:

Type of Debt	Maturity	Interest Rates at December 31,		December 31,	
		2007	2006	2007	2006
(in thousands)					
Pollution Control Bonds, Guadalupe-Blanco River Auth., Series 2005 (a)	2015	4.00%	3.75%	\$ 40,890	\$ 40,890
Pollution Control Bonds, Red River Auth. of Texas, Series 1996 (a)	2020	-	6.00%	-	6,330
Pollution Control Bonds, Red River Auth. of Texas, Series 2007 (a)	2020	4.45%	-	6,330	-
Pollution Control Bonds, Matagorda Co. Navigation District #1, Series 2005C-1 (a)	2028	4.25%	3.65%	60,000	60,000
Pollution Control Bonds, Matagorda Co. Navigation District #1, Series 2005C-2 (a)	2028	4.15%	3.60%	60,265	60,265
Pollution Control Bonds, Matagorda Co. Navigation District #1, Series 2005B (a)	2030	4.55%	4.55%	50,000	50,000
Pollution Control Bonds, Matagorda Co. Navigation District #1, Series 2005A (a)	2030	4.40%	4.40%	111,700	111,700
Pollution Control Bonds, Matagorda Co. Navigation District #1, Series 1996 (a)	2030	5.20%	6.125%	60,000	60,000
Unamortized Premium (Discount)				(199)	(208)
Total Pollution Control Bonds				<u>388,986</u>	<u>388,977</u>
Senior Unsecured Notes, Series B	2033	6.65%	6.65%	275,000	275,000
Unamortized Premium (Discount)				(1,126)	(1,170)
Total Senior Unsecured Notes				<u>273,874</u>	<u>273,830</u>
First Mortgage Bonds, Series GG (b)	2008	7.125%	7.125%	18,581	18,581
Total First Mortgage Bonds				<u>18,581</u>	<u>18,581</u>
Securitization Bonds, Class 2002 A-2	2008 (d)	5.01%	5.01%	28,919	81,649
Securitization Bonds, Class 2006 A-1 (c)	2010 (d)	4.98%	4.98%	191,503	217,000
Securitization Bonds, Class 2002 A-3	2010 (d)	5.56%	5.56%	107,094	107,094
Securitization Bonds, Class 2006 A-2 (c)	2013 (d)	4.98%	4.98%	341,000	341,000
Securitization Bonds, Class 2002 A-4	2013 (d)	5.96%	5.96%	214,927	214,927
Securitization Bonds, Class 2006 A-3 (c)	2015 (d)	5.09%	5.09%	250,000	250,000
Securitization Bonds, Class 2002 A-5	2016 (d)	6.25%	6.25%	191,857	191,857
Securitization Bonds, Class 2006 A-4 (c)	2018 (d)	5.17%	5.17%	437,000	437,000
Securitization Bonds, Class 2006 A-5 (c)	2020 (d)	5.3063%	5.3063%	494,700	494,700
Unamortized Premium (Discount)				(888)	(1,001)
Total Securitization Bonds				<u>2,256,112</u>	<u>2,334,226</u>
Total Long-term Debt				2,937,553	3,015,614
Less: Long-term Debt Due Within One Year				143,419	78,227
Long-term Debt				<u>\$ 2,794,134</u>	<u>\$ 2,937,387</u>

- (a) Under the terms of the Pollution Control Bonds, TCC is required to pay amounts sufficient to enable the payment of interest on and the principal of (at stated maturities and upon mandatory redemptions) related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants. For certain series of pollution control bonds, interest rates are subject to periodic adjustment. Interest payments range from weekly to semi-annually. Letters of credit from banks, standby bond purchase agreements and insurance policies support certain series.
- (b) In May 2004, cash and treasury securities were deposited with a trustee to defease all of TCC's outstanding First Mortgage Bonds. The defeased TCC First Mortgage Bonds had a balance of \$19 million in 2007 and 2006. Interest payments were made semi-annually. The defeased TCC First Mortgage Bond was retired in February 2008. Trust fund assets related to this obligation of \$22 and \$2 million are included in Other Cash Deposits on TCC's Consolidated Balance Sheets at December 31, 2007 and 2006, respectively, and \$21 million is included in Deferred Charges and Other on TCC's Consolidated Balance Sheets at December 31, 2006. Trust fund assets are restricted for exclusive use in funding the interest and principal due on the First Mortgage Bonds.

- (c) In October 2006, AEP Texas Central Transition Funding II LLC (TFII), a subsidiary of TCC, issued \$1.7 billion in Securitization Bonds. TFII is the sole owner of the transition charges and the original transition property. The holders of the Securitization Bonds do not have recourse to any assets or revenues of TCC. The creditors of TCC do not have recourse to any assets or revenues of TFII, including, without limitation, the original transition property.
- (d) This date represents the scheduled final payment date for this class of TCC's Securitization Bonds. The contractual maturity date is one to two years later. These bonds have been classified for repayment purposes based on the scheduled final payment date.

At December 31, 2007 future annual long-term debt payments are as follows:

	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>	<u>2012</u>	<u>After 2012</u>	<u>Total</u>
	(in thousands)						
Principal Amount	\$ 143,419	\$ 137,141	\$ 147,833	\$ 159,443	\$ 171,574	\$ 2,180,356	\$ 2,939,766
Unamortized Discount							(2,213)
Total Long-term Debt							<u>\$ 2,937,553</u>

In January 2008, TCC retired \$28.9 million of 5.01% securitization bonds.

In January 2008, TCC retired \$44.9 million of 4.98% securitization bonds.

As of December 31, 2007, TCC had \$161 million of tax-exempt long-term debt (Pollution Control Bonds) sold at auction rates that are reset every 7 or 35 days and are insured by bond insurers previously AAA-rated, namely Ambac Assurance Corporation, Financial Guaranty Insurance Co., MBIA Insurance Corporation and XL Capital Assurance Inc. Due to the exposure that these bond insurers have in connection with recent developments in the subprime credit market, the credit ratings of these insurers have been downgraded or placed on negative outlook. This has contributed to higher interest rates in successful auctions and increasing occurrences of failed auctions, including auctions of TCC's tax-exempt long-term debt. The instruments under which the bonds are issued allow for conversion to other short-term variable-rate structures, term-put structures and fixed-rate structures. Management is planning to reduce TCC's outstanding auction rate market securities by redeeming, refunding or converting such debt securities to other permitted modes, including term-put and fixed-rate structures. This change may result in additional transaction costs and higher interest charges for the tax-exempt long-term debt.

Lines of Credit – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries. The AEP System corporate borrowing program operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding loans (borrowings) to/from the Utility Money Pool as of December 31, 2007 and 2006 are included in Advances to/from Affiliates on TCC's balance sheets. TCC's Utility Money Pool activity and corresponding authorized borrowing limits for the years ended December 31, 2007 and 2006 are described in the following table:

<u>Year</u>	<u>Maximum Borrowings from Utility Money Pool</u>	<u>Maximum Loans to Utility Money Pool</u>	<u>Average Borrowings from Utility Money Pool</u>	<u>Average Loans to Utility Money Pool</u>	<u>Loans to Utility Money Pool as of December 31,</u>	<u>Authorized Short-Term Borrowing Limit</u>
	(in thousands)					
2007	\$ -	\$ 394,180	\$ -	\$ 188,278	\$ 180,926	\$ 600,000
2006	117,429	818,415	44,416	199,100	394,004	600,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool for the years ended December 31, 2007, 2006 and 2005 are summarized in the following table:

Years Ended	Maximum Interest Rates for Funds Borrowed from the Utility Money Pool	Minimum Interest Rates for Funds Borrowed from the Utility Money Pool	Maximum Interest Rates for Funds Loaned to the Utility Money Pool	Minimum Interest Rates for Funds Loaned to the Utility Money Pool	Average Interest Rates for Funds Borrowed from the Utility Money Pool	Average Interest Rates for Funds Loaned to the Utility Money Pool
December 31,						
2007	-%	-%	5.94%	5.16%	-%	5.41 %
2006	5.39%	4.37%	5.41%	3.32%	4.79%	4.24 %
2005	4.49%	1.63%	3.81%	1.92%	3.18%	2.43 %

Interest expense and interest income related to the Utility Money Pool are included in Interest Expense and Interest Income, respectively, in TCC’s Consolidated Statements of Operations. For amounts borrowed from and advanced to the Utility Money Pool, TCC incurred the following amounts of interest expense and earned the following amounts of interest income, respectively, respectively, for the years ended December 31, 2007, 2006 and 2005:

	Years Ended December 31,		
	2007	2006	2005
		(in thousands)	
Interest Expense	\$ -	\$ 724	\$ 3,272
Interest Income	10,606	5,591	66

Dividend Restrictions

Under the Federal Power Act, TCC is restricted from paying dividends out of stated capital.

14. RELATED PARTY TRANSACTIONS

For other related party transactions, also see “Lines of Credit – AEP System” section of Note 13.

CSW Operating Agreement

PSO, SWEPCo and AEPSC are parties to a Restated and Amended Operating Agreement originally dated as of January 1, 1997 (CSW Operating Agreement), which was approved by the FERC. In February 2006, AEP filed with the FERC a proposed amendment to the CSW Operating Agreement to remove TCC and TNC as parties to the agreement. Pursuant to Texas electric restructuring law, those companies exited the generation and load-servicing businesses. AEP made a similar filing to remove those two companies as parties to the System Integration Agreement. The filings were approved effective May 1, 2006 and April 1, 2006, respectively.

The CSW Operating Agreement requires the parties to maintain adequate annual planning reserve margins and requires that capacity in excess of the required margins be made available for sale to other operating companies as capacity commitments. Parties are compensated for energy delivered to recipients based upon the deliverer’s incremental cost plus a portion of the recipient’s savings realized by the purchaser that avoids the use of more costly alternatives. Revenues and costs arising from third party sales are generally shared based on the amount of energy parties contribute that is sold to third parties.

System Integration Agreement (SIA)

AEP’s System Integration Agreement, which has been approved by the FERC, provides for the integration and coordination of AEP’s East companies and West companies zones. This includes joint dispatch of generation within the AEP System, and the distribution, between the two zones, of costs and benefits associated with the transfers of power between the two zones (including sales to third parties and risk management and trading activities). It is designed to function as an umbrella agreement in addition to the Interconnection Agreement and the CSW Operating Agreement, each of which controls the distribution of costs and benefits within each zone.

In November 2005, AEP filed with the FERC a proposed amendment to the SIA to change the method of allocating profits from off-system electricity sales between the East and West zones. The proposed method causes such profits to be allocated generally on the basis of the zone in which the underlying transactions occur or originate. The filing was made in accordance with a provision of the agreement that called for a re-evaluation of the allocation method effective January 1, 2006 and was approved as filed effective April 1, 2006. As discussed earlier, TCC is no longer a party to the SIA.

Power generated by or allocated or provided under the Interconnection Agreement or CSW Operating Agreement to TCC is primarily sold to REPs at market rates.

Under both the Interconnection Agreement and CSW Operating Agreement, power generated that is not needed to serve the AEP System native load is sold in the wholesale market by AEPSC on behalf of the generating subsidiary.

Affiliated Revenues

TCC's other revenues derived from sales to affiliates for the years ended December 31, 2007, 2006 and 2005 were \$5.7 million, \$6.4 million and \$15 million, respectively. These related party revenues are reported as Sales to AEP Affiliates on TCC's Consolidated Statements of Operations.

AEP System Transmission Pool

AEP's System Transmission Integration Agreement provides for the integration and coordination of the planning, operation and maintenance of the transmission facilities of AEP's East companies and AEP West companies zones. The System Transmission Integration Agreement functions as an umbrella agreement in addition to the Transmission Equalization Agreement (TEA) and the Transmission Coordination Agreement (TCA). The System Transmission Integration Agreement contains two service schedules that govern:

- The allocation of transmission costs and revenues and
- The allocation of third-party transmission costs and revenues and AEP System dispatch costs.

The Transmission Integration Agreement anticipates that additional service schedules may be added as circumstances warrant.

APCo, CSPCo, I&M, KPCo and OPCo are parties to the TEA, dated April 1, 1984, as amended, defining how they share the costs associated with their relative ownership of the extra-high-voltage transmission system (facilities rated 345 kV and above) and certain facilities operated at lower voltages (138 kV and above).

PSO, SWEPCo, TCC, TNC and AEPSC are parties to the TCA, originally dated January 1, 1997. The TCA has been approved by the FERC and establishes a coordinating committee, which is charged with overseeing the coordinated planning of the transmission facilities of the AEP West companies, including the performance of transmission planning studies, the interaction of such companies with independent system operators (ISO) and other regional bodies interested in transmission planning and compliance with the terms of the OATT filed with the FERC and the rules of the FERC relating to such tariff.

Under the TCA, the AEP West companies delegated to AEPSC the responsibility of monitoring the reliability of their transmission systems and administering the OATT on their behalf. Prior to September 2005, TCA also provided for the allocation among the AEP West companies of revenues collected for transmission and ancillary services provided under the OATT. Since then, these allocations have been governed by the FERC-approved OATT for the SPP (with respect to PSO and SWEPCo) and PUCT-approved protocols for ERCOT (with respect to TCC and TNC).

TCC's net charges (credits) allocated under the TCA prior to September 2005, and pursuant to the ERCOT protocols as described above during the years ended December 31, 2007, 2006 and 2005 are as follows:

Years Ended December 31,		
2007	2006	2005
(in thousands)		
\$ 1,100	\$ 1,100	\$ (3,800)

The net charges (credits) shown above are recorded in Other Operation on TCC's Consolidated Statements of Operations.

Jointly-Owned Electric Utility Plant

PSO and TNC jointly own the Oklaunion power plant along with two nonaffiliated companies. TCC sold its share to one of the nonaffiliated owners in February 2007. The costs of operating the facility are apportioned between owners based on ownership interests. Each company's share of these costs is included in the appropriate expense accounts on its respective income statement. TCC's share was included in Assets Held for Sale – Texas Generation Plant on the December 31, 2006 balance sheet.

Purchased Power from Sweeny

On behalf of the AEP West companies, CSPCo entered into a ten year Power Purchase Agreement (PPA) with Sweeny, which was 50% owned by AEP. The PPA was for unit contingent power up to a maximum of 315 MW from January 1, 2005 through December 31, 2014. The delivery point for the power under the PPA was in TCC's system. The power was sold in ERCOT. Prior to May 1, 2006, the purchase of Sweeny power and its sale to nonaffiliates were shared among the AEP West companies under the CSW Operating Agreement. After May 1, 2006, the purchases and sales were shared between PSO and SWEPCo. See "CSW Operating Agreement" section of this note. In April 2007, AEP Energy Partners (AEPEP) was assigned the Sweeny PPA from CSPCo and became responsible for purchasing the Sweeny power instead of PSO and SWEPCo. In October 2007, AEP sold its 50% interest in the Sweeny facility along with the ten year PPA to Conoco Phillips. TCC's purchases from Sweeny were \$703 thousand and \$4.6 million for the years ended December 31, 2006 and 2005, respectively. These amounts are recorded in Purchased Electricity for Resale on TCC's Consolidated Statements of Operations.

Sales and Purchases of Property

TCC had purchases of electric property from TNC individually amounting to \$100 thousand or more for the year ended December 31, 2007 of \$2.3 million.

TCC had aggregate affiliated sales and purchases of meters and transformers for the years ended December 31, 2007, 2006 and 2005 as shown in the following table:

	APCo	CSPCo	I&M	KGPCo	KPCo	OPCo	PSO	SWEPCo	TNC	TOTAL
<u>Sales</u>	(in thousands)									
2007	\$ 20	\$ 13	\$ -	\$ -	\$ -	\$ 40	\$ 1	\$ 76	\$ 763	\$ 913
2006	12	-	-	36	-	18	10	50	1,266	1,392
2005	164	-	2	-	-	29	2	130	1,642	1,969
<u>Purchases</u>										
2007	\$ 61	\$ -	\$ 4	\$ -	\$ -	\$ 6	\$ -	\$ 26	\$ 199	\$ 296
2006	1,631	-	2	179	3	1	30	37	209	2,092
2005	357	-	-	-	-	69	8	40	317	791

The amounts above are recorded in Property, Plant and Equipment. Transfers are performed at cost.

AEPSC

AEPSC provides certain managerial and professional services to AEP System companies. The costs of the services are billed to TCC by AEPSA on a direct-charge basis, whenever possible, and on reasonable bases of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital, which is furnished to AEPSA by AEP. Billings from AEPSA are capitalized or expensed depending on the nature of the services rendered and are recoverable from customers. During 2005, AEPSA and its billings were subject to regulation by the SEC under the PUHCA of 1935. Effective February 8, 2006, the PUHCA of 2005 was enacted, which repealed the PUHCA of 1935 and transferred the regulatory responsibility from the SEC to the FERC.

Intercompany Billings

TCC performs certain utility services for other AEP subsidiaries when necessary or practical. The costs of these services are billed on a direct-charge basis, whenever possible, or on reasonable bases of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital. Billings are capitalized or expensed depending on the nature of the services rendered.

15. PROPERTY, PLANT AND EQUIPMENT

Depreciation

TCC provides for depreciation of Property, Plant and Equipment on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following table provides the annual composite depreciation rates by functional class:

2007		Regulated			Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Transmission	\$ 962,859	\$ 215,553	1.6%	50-81	\$ -	\$ -	N.M.	N.M.
Distribution	1,670,120	354,803	3.2%	22-64	-	-	N.M.	N.M.
CWIP	122,666	(3,684)	N.M.	N.M.	-	-	N.M.	N.M.
Other	228,593	99,417	6.0%	N.M.	2,978	1,035	N.M.	N.M.
Total	\$ 2,984,238	\$ 666,089			\$ 2,978	\$ 1,035		

2006		Regulated			Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Transmission	\$ 904,527	\$ 208,121	1.6%	40-71	\$ -	\$ -	N.M.	N.M.
Distribution	1,579,498	331,297	3.3%	15-62	-	-	N.M.	N.M.
CWIP	165,979	362	N.M.	N.M.	-	-	N.M.	N.M.
Other	217,050	89,448	6.8%	N.M.	2,978	1,011	N.M.	N.M.
Total	\$ 2,867,054	\$ 629,228			\$ 2,978	\$ 1,011		

2005		Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges	
		(in years)		(in years)	
Transmission	2.1%	40-71	N.M.	N.M.	
Distribution	3.4%	15-62	N.M.	N.M.	
Other	6.5%	N.M.	2.9%	N.M.	

N.M. = Not Meaningful

The composite depreciation rate generally includes a component for nonasset retirement obligation (non-ARO) removal costs, which is credited to Accumulated Depreciation and Amortization. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability.

Asset Retirement Obligations (ARO)

TCC implemented SFAS 143 effective January 1, 2003. SFAS 143 requires entities to record a liability at fair value for any legal obligations for future asset retirements when the related assets are acquired or constructed. Upon establishment of a legal liability, SFAS 143 requires a corresponding ARO asset to be established, which will be depreciated over its useful life. Upon settlement of an ARO, TCC recognizes any difference between the ARO liability and actual costs as income or expense.

TCC adopted FIN 47 during the fourth quarter of 2005. FIN 47 interprets the application of SFAS 143. It clarifies that conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Entities are required to record a liability for the fair value of a conditional ARO if the fair value of the liability can be reasonably estimated. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an ARO.

TCC completed a review of its FIN 47 conditional ARO and concluded that legal liabilities exist for asbestos removal and disposal in general buildings and generating plants. In 2005, TCC recorded a liability for conditional ARO of \$1.2 million in accordance with FIN 47.

TCC has identified, but not recognized, ARO liabilities related to electric transmission and distribution assets, as a result of certain easements on property on which assets are owned. Generally, such easements are perpetual and require only the retirement and removal of assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since TCC plans to use its facilities indefinitely. The retirement obligation would only be recognized if and when TCC abandons or ceases the use of specific easements, which is not expected.

The following is a reconciliation of the 2007 and 2006 aggregate carrying amounts of ARO for TCC:

<u>Year</u>	<u>ARO at January 1,</u>	<u>Accretion Expense</u>	<u>Liabilities Incurred</u>	<u>Liabilities Settled</u>	<u>Revisions in Cash Flow Estimates</u>	<u>ARO at December 31,</u>
	(in thousands)					
2007	\$ 1,239	\$ 79	\$ 12	\$ -	\$ -	\$ 1,330
2006	1,165	74	-	-	-	1,239

TCC's aggregate carrying amounts include ARO related to asbestos removal.

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

The amounts of AFUDC included in Allowance For Equity Funds Used During Construction on TCC's Consolidated Statements of Operations was \$3.2 million, \$2.7 million and \$1.0 million for December 31, 2007, 2006 and 2005, respectively.

The amounts of allowance for borrowed funds used during construction or interest capitalized included in Interest Expense on TCC's Consolidated Statements of Operations was \$2.7 million, \$2.6 million and \$1.5 million for December 31, 2007, 2006 and 2005, respectively.

Jointly-owned Electric Utility Plant

In February 2007, TCC sold its 7.8% ownership share of Unit No. 1 at the Oklaunion Generating Station that was jointly-owned with PSO, TNC and various nonaffiliated companies. Each of the participating companies was obligated to pay its share of the costs in the same proportion as its ownership interest. TCC's proportionate share of the operating costs associated with this facility is included in its Consolidated Statements of Operations. At December 31, 2006, the investment and accumulated depreciation was reflected in TCC's Consolidated Balance Sheets under Assets Held for Sale – Texas Generation Plant as follows:

<u>TCC's Share at December 31, 2006</u>	<u>Fuel Type</u>	<u>Percent of Ownership</u>	<u>Utility Plant Held for Sale</u>	<u>Accumulated Depreciation</u>
			(in thousands)	
Oklaunion Generating Station (Unit No. 1) (a)	Coal	7.8 %	\$ 39,660	\$ 19,671

(a) Operated by PSO.

16. UNAUDITED QUARTERLY FINANCIAL INFORMATION

In management's opinion, the unaudited quarterly information reflects all normal and recurring accruals and adjustments necessary for a fair presentation of the results of operations for interim periods. Quarterly results are not necessarily indicative of a full year's operations because of various factors. TCC's unaudited quarterly financial information is as follows:

	<u>March 31</u>	<u>2007 Quarterly Periods Ended</u>		<u>December 31</u>
		<u>June 30</u>	<u>September 30</u>	
		(in thousands)		
Operating Revenues	\$ 176,931	\$ 202,743	\$ 235,649	\$ 193,282
Operating Income	44,872	60,048	87,464	47,185
Net Income	3,538	12,124	29,958	13,330

	<u>March 31</u>	<u>2006 Quarterly Periods Ended</u>		<u>December 31</u>
		<u>June 30</u>	<u>September 30</u>	
		(in thousands)		
Operating Revenues	\$ 135,288	\$ 161,489	\$ 173,923	\$ 193,964
Operating Income	11,468	33,411	35,771	48,447
Net Income	3,773	16,975	17,235	3,586

There were no significant events in the fourth quarter of 2007 or 2006.