AEP Texas North Company

and Subsidiary

2008 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.
CO_2	Carbon Dioxide.
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.
EIS	Energy Insurance Services, Inc., a protected cell insurance company that AEP consolidates due to FIN 46.
EITF	Financial Accounting Standards Board's Emerging Issues Task Force.
EITF 06-10	EITF Issue No. 06-10 "Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements."
ERCOT	Electric Reliability Council of Texas.
ERISA	Employee Retirement Income Security Act of 1974, as amended.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN	FASB Interpretation No.
FIN 46R	FIN 46R, "Consolidation of Variable Interest Entities."
FIN 48	FIN 48, "Accounting for Uncertainty in Income Taxes" and FASB Staff Position FIN 48-1 "Definition of *Settlement* in FASB Interpretation No. 48."
FSP	FASB Staff Position.
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.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
kV	Kilovolt.
MTM	Mark-to-Market.

Term	Meaning
MW	Megawatt.
Nonutility Money Pool	AEP System’s Nonutility Money Pool.
OATT	Open Access Transmission Tariff.
OCC	Corporation Commission of the State of Oklahoma.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCT	Public Utility Commission of Texas.
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.
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 158	Statement of Financial Accounting Standards No. 158, “Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans.”
SIA	System Integration Agreement.
SPP	Southwest Power Pool.
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.
Utility Money Pool	AEP System’s Utility Money Pool.

INDEPENDENT AUDITORS' REPORT

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

We have audited the accompanying consolidated balance sheets of AEP Texas North Company and subsidiary (the "Company") as of December 31, 2008 and 2007, and the related consolidated statements of income, 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, 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with 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 North Company and subsidiary as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 10 to the consolidated financial statements, the Company adopted FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes," effective January 1, 2007. As discussed in Note 7 to the consolidated financial statements, the Company adopted FASB Statement No. 158, "Accounting for Defined Benefit Pension and Other Postretirement Plans," effective December 31, 2006.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2009

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2008, 2007 and 2006
(in thousands)

	2008	2007	2006
REVENUES			
Electric Generation, Transmission and Distribution	$ 176,397	$ 178,763	$ 295,930
Sales to AEP Affiliates	100,523	96,397	33,225
Other	866	5,065	315
TOTAL	277,786	280,225	329,470
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	49,358	37,172	46,710
Purchased Electricity for Resale	1,249	8,059	78,708
Other Operation	84,219	77,928	81,437
Maintenance	21,445	21,308	21,846
Depreciation and Amortization	45,406	41,335	42,914
Taxes Other Than Income Taxes	17,889	20,421	22,568
TOTAL	219,566	206,223	294,183
OPERATING INCOME	58,220	74,002	35,287
Other Income (Expense):			
Interest Income	9,199	1,262	643
Allowance for Equity Funds Used During Construction	1,901	265	886
Interest Expense	(21,652)	(16,088)	(17,619)
INCOME BEFORE INCOME TAX EXPENSE	47,668	59,441	19,197
Income Tax Expense	13,752	20,092	4,254
NET INCOME	33,916	39,349	14,943
Preferred Stock Dividend Requirements	103	103	103
Gain on Reacquired Preferred Stock	-	-	2
EARNINGS APPLICABLE TO COMMON STOCK	$ 33,813	$ 39,246	$ 14,842

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

See Notes to Consolidated Financial Statements.

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2008, 2007 and 2006
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2005	$ 137,214	$ 2,351	$ 174,858	$ (504)	$ 313,919
Common Stock Dividends			(12,750)		(12,750)
Preferred Stock Dividends			(103)		(103)
Gain on Reacquired Preferred Stock			2		2
TOTAL					301,068
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $318				(591)	(591)
Minimum Pension Liability, Net of Tax of $37				68	68
NET INCOME			14,943		14,943
TOTAL COMPREHENSIVE INCOME					14,420
Minimum Pension Liability Elimination, Net of Tax of $175				325	325
SFAS 158 Adoption, Net of Tax of $5,092				(9,457)	(9,457)
DECEMBER 31, 2006	137,214	2,351	176,950	(10,159)	306,356
FIN 48 Adoption, Net of Tax			(557)		(557)
Common Stock Dividends			(14,000)		(14,000)
Preferred Stock Dividends			(103)		(103)
TOTAL					291,696
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $378				702	702
Pension and OPEB Funded Status, Net of Tax of $79				148	148
NET INCOME			39,349		39,349
TOTAL COMPREHENSIVE INCOME					40,199
DECEMBER 31, 2007	137,214	2,351	201,639	(9,309)	331,895
EITF 06-10 Adoption, Net of Tax of $153			(285)		(285)
Common Stock Dividends			(35,000)		(35,000)
Preferred Stock Dividends			(103)		(103)
TOTAL					296,507
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $347				644	644
Pension and OPEB Funded Status, Net of Tax of $4,087				(7,591)	(7,591)
NET INCOME			33,916		33,916
TOTAL COMPREHENSIVE INCOME					26,969
DECEMBER 31, 2008	$ 137,214	$ 2,351	$ 200,167	$ (16,256)	$ 323,476

See Notes to Consolidated Financial Statements.

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2008 and 2007
(in thousands)

	2008	2007
CURRENT ASSETS		
Cash and Cash Equivalents	$ 200	$ -
Accounts Receivable:		
Customers	9,674	10,255
Affiliated Companies	65,731	37,999
Accrued Unbilled Revenues	4,289	4,053
Miscellaneous	55	47
Allowance for Uncollectible Accounts	(47)	(25)
Total Accounts Receivable	79,702	52,329
Fuel	9,808	11,575
Materials and Supplies	10,339	9,994
Prepayments and Other	1,367	5,534
TOTAL	101,416	79,432
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	295,065	292,109
Transmission	411,839	344,339
Distribution	548,424	523,248
Other	107,844	160,494
Construction Work in Progress	82,283	66,761
Total	1,445,455	1,386,951
Accumulated Depreciation and Amortization	458,868	498,590
TOTAL - NET	986,587	888,361
OTHER NONCURRENT ASSETS		
Regulatory Assets	67,943	36,536
Deferred Charges and Other	3,076	18,160
TOTAL	71,019	54,696
TOTAL ASSETS	$ 1,159,022	$ 1,022,489

See Notes to Consolidated Financial Statements.

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2008 and 2007

	2008	2007
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 28,686	$ 33,511
Accounts Payable:		
General	7,236	11,651
Affiliated Companies	47,572	46,855
Accrued Taxes	16,714	18,941
Accrued Interest	5,914	4,024
Provision for Revenue Refund	9,400	-
Other	21,231	9,688
TOTAL	136,753	124,670
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	368,965	268,875
Deferred Income Taxes	124,071	126,667
Regulatory Liabilities and Deferred Investment Tax Credits	131,022	128,139
Employee Benefits and Pension Obligations	42,596	14,908
Deferred Credits and Other	29,790	24,986
TOTAL	696,444	563,575
TOTAL LIABILITIES	833,197	688,245
Cumulative Preferred Stock Not Subject to Mandatory Redemption	2,349	2,349
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $25 Per Share:		
Authorized – 7,800,000 Shares		
Outstanding – 5,488,560 Shares	137,214	137,214
Paid-in Capital	2,351	2,351
Retained Earnings	200,167	201,639
Accumulated Other Comprehensive Income (Loss)	(16,256)	(9,309)
TOTAL	323,476	331,895
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 1,159,022	$ 1,022,489

See Notes to Consolidated Financial Statements.

AEP TEXAS NORTH COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2008, 2007 and 2006
(in thousands)

	2008	2007	2006
OPERATING ACTIVITIES			
Net Income	$ 33,916	$ 39,349	$ 14,943
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	45,406	41,335	42,914
Deferred Income Taxes	5,386	(737)	(227)
Provision for Revenue Refund	9,400	-	-
Allowance for Equity Funds Used During Construction	(1,901)	(265)	(886)
Mark-to-Market of Risk Management Contracts	-	-	625
Fuel Over/Under-Recovery, Net	(54)	(7,777)	2,915
Change in Other Noncurrent Assets	(6,463)	(3,562)	(6,250)
Change in Other Noncurrent Liabilities	3,647	(4,016)	(7,812)
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(27,373)	(22,670)	79,166
Fuel, Materials and Supplies	1,422	(3,691)	(8,384)
Accounts Payable	(1,763)	4,111	(54,379)
Accrued Taxes, Net	(2,449)	(838)	570
Other Current Assets	296	187	1,395
Other Current Liabilities	11,387	(563)	(3,175)
Net Cash Flows from Operating Activities	70,857	40,863	61,415
INVESTING ACTIVITIES			
Construction Expenditures	(132,720)	(88,048)	(70,350)
Change in Other Cash Deposits	-	8,858	1,203
Change in Advances to Affiliates, Net	-	13,543	20,743
Acquisitions of Assets	(424)	-	-
Proceeds from Sales of Assets	3,555	14,596	330
Net Cash Flows Used for Investing Activities	(129,589)	(51,051)	(48,074)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	99,346	43,681	-
Change in Advances from Affiliates, Net	(4,825)	33,511	-
Retirement of Long-term Debt – Nonaffiliated	-	(52,461)	-
Retirement of Cumulative Preferred Stock	-	-	(6)
Principal Payments for Capital Lease Obligations	(588)	(524)	(398)
Dividends Paid on Common Stock	(35,000)	(14,000)	(12,750)
Dividends Paid on Cumulative Preferred Stock	(103)	(103)	(103)
Other	102	-	-
Net Cash Flows from (Used for) Financing Activities	58,932	10,104	(13,257)
Net Increase (Decrease) in Cash and Cash Equivalents	200	(84)	84
Cash and Cash Equivalents at Beginning of Period	-	84	-
Cash and Cash Equivalents at End of Period	$ 200	$ -	$ 84
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 16,495	$ 15,589	$ 15,457
Net Cash Paid for Income Taxes	12,893	20,698	5,834
Noncash Acquisitions Under Capital Leases	383	202	1,291
Construction Expenditures Included in Accounts Payable at December 31,	5,336	7,271	1,317
Revenue Refund Included in Accounts Receivable at December 31,	24,763	-	-

See Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Summary of Significant Accounting Policies
2. New Accounting Pronouncements
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6. Disposition
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1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

As a public utility, TNC engages in the transmission and distribution of electric power to 185,000 retail customers through REPs in its service territory in western and central Texas.

Under the Texas Restructuring Legislation, TNC completed the final state of exiting the generation business and ceased serving retail load. Although TNC continues as part owner in the Oklaunion Plant operated by PSO, TNC has leased their entire portion of the output of the plant through 2027 to a non-utility affiliate. Based on the corporate separation and generation divestiture, the nature of TNC 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, TNC sought and received FERC approval to be removed from those agreements. TNC'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. These trading and marketing margins affected TNC's net income and cash flows.

Prior to May 1, 2006, as a member of the CSW Operating Agreement, TNC 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, AEPSC allocated physical and financial revenues and expenses from neighboring utilities, power marketers and other power and gas risk management activities among AEP East companies and AEP West companies based on an allocation methodology established at the time of the AEP-CSW merger. 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. This activity 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 were also 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.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

The PUCT approves rates and regulates the services and operations for a majority of TNC's transmission and distribution energy delivery services. TNC's affiliated transactions, including AEPSC intercompany service billings which are generally at cost, are regulated by the FERC under the 2005 Public Utility Holding Company Act, the Federal Power Act and by the PUCT. The FERC also has jurisdiction over the issuances and acquisitions of securities of the public utility holding company subsidiaries, such as TNC, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. A FERC order in 2008 pursuant to the Federal Power Act codified that for non-power goods and services, a non-regulated affiliate can bill a public utility company no more than market while a public utility must bill the higher of cost or market to a non-regulated affiliate.

The FERC regulates wholesale power markets and wholesale power transactions. Prior to January 1, 2007, TNC's wholesale power transactions were generally market-based. They were cost-based regulated when TNC negotiated and filed a cost-based contract with the FERC or the FERC determined that TNC had "market power" in the region where the transaction occurred. Prior to January 1, 2007, TNC entered into wholesale power supply contracts with various municipalities and cooperatives that were FERC-regulated, market-based contracts. TNC wholesale power transactions in the SPP region were all cost-based due to TNC having market power in the SPP region. Effective January 1, 2007, all of TNC's supply contacts were assigned to AEP Energy Partners.

TNC's wholesale transmission rates are regulated on a cost basis by the PUCT. TNC offers no retail transmission service.

In addition, the FERC regulates the SIA, the CSW Operating Agreement, the System Transmission Integration Agreement and the Transmission Coordination Agreement, all of which allocate shared system costs and revenues to the utility subsidiaries that are parties to each agreement, including TNC. The sharing of margins with the AEP East companies under the SIA ceased on April 1, 2006. In May 2006, the FERC approved the removal of TNC from the CSW Operating Agreement.

The PUCT regulates all of TNC's public utility services/operations where transmission and distribution rates are regulated on a cost-basis and unbundled by function. TNC has no Texas jurisdictional retail generation/power supply operations.

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

Principles of Consolidation

TNC's consolidated financial statements include TNC and its wholly-owned subsidiary. Intercompany items are eliminated in consolidation. TNC also has a generating unit that is jointly-owned with an affiliated company and nonaffiliated companies. TNC's proportionate share of the operating costs associated with that facility is included in the financial statements and the assets and liabilities are reflected in the balance sheets. See "Oklaunion PPA between TNC and AEP Energy Partners" section within Note 13 for detail of TNC's agreement to sell its portion of the Oklaunion generation to AEPEP. See "Variable Interest Entities" section of Note 13.

Accounting for the Effects of Cost-Based Regulation

As a cost-based rate-regulated electric transmission and distribution company, TNC's financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with SFAS 71, regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues and income with its passage to customers through the reduction of regulated revenues. Due to the commencement of legislatively required restructuring and a transition to customer choice and market-based rates, TNC discontinued the application of SFAS 71, regulatory accounting, for the generation portion of its business in September 1999.

Use of Estimates

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

Property, Plant and Equipment and Equity Investments

Electric utility property, plant and equipment are stated at original purchase cost. Property, plant and equipment of nonregulated operations and other investments are stated at fair market value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Additions, major replacements and betterments are added to the plant accounts. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for both cost-based rate-regulated and nonregulated operations under the group composite method of depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in the original cost, less salvage, being charged to accumulated depreciation. For the nonregulated generation assets, a gain or loss would be recorded if the retirement is not considered an interim routine replacement. The depreciation rates that are established for the generating plants take into account the past history of interim capital replacements and the amount of salvage received. These rates and the related lives are subject to periodic review. Removal costs are charged to regulatory liabilities for cost-based rate-regulated operations and charged to expense for nonregulated operations. The costs of labor, materials and overhead incurred to operate and maintain 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) and Interest Capitalization

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant. For nonregulated operations including generating assets in Texas effective with the discontinuance of SFAS 71 regulatory accounting, interest is capitalized during construction in accordance with SFAS 34, "Capitalization of Interest Costs."

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Accounts Receivable 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.

Inventory

Fossil fuel inventories are carried at the lower of average cost or market. Materials and supplies inventories are carried at average cost.

Accounts Receivable

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

Revenue is recognized when power is delivered. To the extent that deliveries have occurred but a bill has not been issued, TNC accrues and recognizes, as Accrued Unbilled Revenues, an estimate of the revenues for deliveries since the last billing.

Concentrations of Credit Risk and Significant Customers

TNC 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:

	2008	2007	2006
TNC – Centrica, ERCOT (2006 only) and City of College Station (2006 only)			
Percentage of Operating Revenues	21%	15%	50%
Percentage of Accounts Receivable - Customers	31%	36%	38%

TNC monitors credit levels and the financial condition of its customers on a continuing basis to minimize credit risk. The PUCT allows recovery in rates for a reasonable level of bad debt costs. 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) and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period and by matching income with its passage to customers in cost-based regulated rates.

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

Traditional Electricity Supply and Delivery Activities

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

Energy Marketing and Risk Management Activities

Prior to TNC's FERC-approved removal from the SIA and CSW Operating Agreement, effective April 1, and May 1, 2006 respectively, AEPSC, on behalf of TNC, 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 and adjacent markets. These 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. Certain energy marketing and risk management transactions were with RTOs.

TNC recognized revenues and expenses from wholesale marketing and risk management transactions that were not derivatives upon delivery of the commodity. TNC 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 a normal purchase or sale. TNC 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 Income 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). TNC 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, TNC subsequently reclassified the gain or loss on the hedge from Accumulated Other Comprehensive Income into revenues or expenses on its Consolidated Statements of Income, 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

TNC 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. TNC includes such revenue and related expenses in Other revenue and Other Operation expense, respectively, in its Consolidated Statements of Income. TNC includes contractually billable expenses not yet billed in Current Assets in its Consolidated Balance Sheets.

Power Purchase and Sale Agreement

TNC recognizes revenue from an affiliate, AEP Energy Partners (AEPEP), for a 20-year Power Purchase & Sale Agreement (PPA). TNC recognizes revenues for the fuel, operations and maintenance and all other taxes on a billed basis. Revenue is recognized for the capacity and depreciation billed to AEPEP on a straight-line basis over the term of the PPA as these amounts represent the minimum payments due.

Maintenance

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

Income Taxes and Investment Tax Credits

TNC 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.

TNC accounts for uncertain tax positions in accordance with FIN 48. Effective with the adoption of FIN 48 beginning January 1, 2007, TNC 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, TNC collects from customers certain excise taxes levied by those state or local governments on customers. TNC 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 subsidiaries 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).

Components of Accumulated Other Comprehensive Income (Loss) (AOCI)

AOCI is included on the balance sheets in the common shareholder's equity section. AOCI for TNC as of December 31, 2008 and 2007 is shown in the following table:

	December 31,	
	2008	2007
Components	(in thousands)	
Amortization of Pension and OPEB Deferred Costs, Net of Tax	$ 644	$ -
Pension and OPEB Funded Status, Net of Tax	(16,900)	(9,309)

Earnings Per Share (EPS)

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

Reclassifications

Certain prior period financial statement items have been reclassified to conform to current period presentation. These reclassifications had no impact on TNC's previously reported net income or changes in shareholders' equity.

2. NEW ACCOUNTING PRONOUNCEMENTS

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

Pronouncements Adopted in 2008

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

SFAS 157 "Fair Value Measurements" (SFAS 157)

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

In February 2008, the FASB issued FSP SFAS 157-1 "Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13" (SFAS 157-1) which amends SFAS 157 to exclude SFAS 13 "Accounting for Leases" and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement under SFAS 13. SFAS 157-1 was effective upon issuance and had no impact on the financial statements.

In February 2008, the FASB issued FSP SFAS 157-2 "Effective Date of FASB Statement No. 157" (SFAS 157-2) which delays the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). TNC fully adopted SFAS 157 effective January 1, 2009 for items within the scope of SFAS 157-2. The adoption of SFAS 157-2 had no impact on the financial statements.

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

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

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

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

SFAS 162 "The Hierarchy of Generally Accepted Accounting Principles" (SFAS 162)

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

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

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

In March 2007, the FASB ratified EITF 06-10, a consensus on collateral assignment split-dollar life insurance arrangements in which an employee owns and controls the insurance policy. Under EITF 06-10, an employer should recognize a liability for the postretirement benefit related to a collateral assignment split-dollar life insurance arrangement if the employer 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 cumulative effect adjustment to retained earnings or other components of equity or net assets in the statement of financial position at the beginning of the year of adoption or (b) retrospective application to all prior periods. TNC adopted EITF 06-10 effective January 1, 2008 with a cumulative effect reduction of $438 thousand ($285 thousand, net of tax) to beginning retained earnings.

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

In June 2007, the FASB addressed the recognition of income tax benefits of dividends on employee share-based compensation. Under EITF 06-11, a realized income tax benefit from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for equity-classified nonvested equity shares, nonvested equity share units and outstanding equity share options should be recognized as an increase to additional paid-in capital.

TNC adopted EITF 06-11 effective January 1, 2008. The adoption of this standard had an immaterial impact on the financial statements.

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

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

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

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

TNC adopted the standard effective December 31, 2008. The adoption of this standard had no impact on the financial statements but increased the guarantees disclosures in Note 5.

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

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

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

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

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

TNC adopted the standard effective December 31, 2008. The adoption of this standard had no impact on the financial statements but increased the footnote disclosures for variable interest entities. See "Variable Interest Entities" section of Note 13.

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

In April 2007, the FASB issued FSP FIN 39-1 amending FIN 39, "Offsetting of Amounts Related to Certain Contracts" by replacing the interpretation's definition of contracts with the definition of derivative instruments per SFAS 133. The amendment requires entities that offset fair values of derivatives with the same party under a netting agreement to 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.

TNC adopted the standard effective January 1, 2008. This standard changed the method of netting certain balance sheet amounts. It had no impact on TNC.

Pronouncements Adopted During The First Quarter of 2009

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

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

In December 2007, the FASB issued SFAS 141R, improving financial reporting about business combinations and their effects. It established how the acquiring entity recognizes and measures the identifiable assets acquired, liabilities assumed, goodwill acquired, any gain on bargain purchases and any noncontrolling interest in the acquired entity. SFAS 141R no longer allows acquisition-related costs to be included in the cost of the business combination, but rather expensed in the periods they are incurred, with the exception of the costs to issue debt or equity securities which shall be recognized in accordance with other applicable GAAP. The standard requires disclosure of information for a business combination that occurs during the accounting period or prior to the issuance of the financial statements for the accounting period. SFAS 141R can affect tax positions on previous acquisitions. TNC does not have any such tax positions that result in adjustments.

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

SFAS 160 "Noncontrolling Interest in Consolidated Financial Statements" (SFAS 160)

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

TNC adopted SFAS 160 effective January 1, 2009. The adoption of this standard had no impact.

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

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

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

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

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

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

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

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

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

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

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

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

Pronouncements Effective in the Future

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

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

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

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

Future Accounting Changes

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

3. RATE MATTERS

TNC 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 net income and cash flows.

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

TEXAS RESTRUCTURING

Texas Restructuring Appeals

TNC received its final true-up order in May 2005 that resulted in refunds via a CTC which have been completed. Appeals brought by intervenors and TNC of the final true-up order remain pending in state court. Management cannot predict the outcome of the court proceedings. If TNC ultimately succeeds in its appeals, it could have a material favorable effect on future net income, cash flows and financial condition. If intervenors succeed in their appeals, it could have a substantial adverse effect on future net income, cash flows and financial condition.

2008 Interim Transmission Rates

In March 2008, TNC filed an application with the PUCT for an interim update of wholesale-transmission rates. The PUCT issued an order in May 2008 that provided for increased interim transmission rates for TNC, subject to review during the next TNC base rate case. This review could result in a refund if the PUCT finds that TNC has not prudently incurred the transmission investment. The FERC approved the new interim transmission rates in May 2008 which increased annual transmission revenues by $4 million. TNC has not recorded any provision for refund regarding the interim transmission rates because management believes these new rates are reasonable and necessary to recover costs associated with new transmission plant. Management cannot predict the outcome of future proceedings related to the interim transmission rates. A refund of the interim transmission rates would have an adverse impact on net income and cash flows.

2009 Interim Transmission Rates

In February 2009, TNC filed an application with the PUCT for an interim update of wholesale-transmission rates. The proposed new interim transmission rates are estimated to increase annual transmission revenues by $9 million on an annual basis, effective March 30, 2009. A decision is expected from the PUCT during the second quarter of 2009 with rates increasing shortly thereafter upon the FERC's concurrence. Management cannot predict the outcome of this interim transmission rates proceeding.

FERC Rate Matters

Allocation of Off-system Sales Margins

In August 2008, the OCC filed a complaint at the FERC alleging that AEP inappropriately allocated off-system sales margins between the AEP East companies and the AEP West companies and did not properly allocate off-system sales margins within the AEP West companies. The PUCT intervened in this filing. In November 2008, the FERC issued a final order concluding that AEP inappropriately deviated from off-system sales margin allocation methods in the AEP SIA and the CSW Operating Agreement for the period June 2000 through March 2006. The FERC ordered AEP to recalculate and reallocate the off-system sales margins in compliance with the AEP SIA and to have the AEP East companies issue refunds to the AEP West companies. Although the FERC determined that AEP deviated from the CSW Operating Agreement, the FERC determined the allocation methodology to be reasonable. The FERC ordered AEP to submit a revised CSW Operating Agreement for the period June 2000 to March 2006. In December 2008, AEP filed a motion for rehearing and a revised CSW Operating Agreement for the period June 2000 to March 2006. The motion for rehearing is still pending. In January 2009, AEP filed a compliance filing with the FERC and refunded approximately $250 million from the AEP East companies to the AEP West companies. The AEP West companies were required to share a portion of such revenues with their wholesale and retail customers during this period. In December 2008, the AEP West companies recorded a provision for refund which had a $97 million unfavorable effect on AEP net income.

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

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

The table below shows the vintage year of the associated AEP SIA refunds:

	For the Twelve Months Ended December 31,			
	2006 and Prior	2007	2008	Total
AEP East Companies	(in millions)			
APCo	$ (66)	$ (6)	$ (5)	$ (77)
I&M	(41)	(4)	(3)	(48)
OPCo	(53)	(5)	(4)	(62)
CSPCo	(40)	(3)	(1)	(44)
KPCo	(17)	(1)	(1)	(19)
Total – AEP East Companies	(217)	(19)	(14)	(250)
AEP West Companies				
PSO	62	6	4	72
SWEPCo	74	6	5	85
TCC	59	5	4	68
TNC	22	2	1	25
Total – AEP West Companies	217	19	14	250
Total – AEP Consolidated	$ -	$ -	$ -	$ -

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

4. EFFECTS OF REGULATION

Regulatory assets and liabilities are comprised of the following items:

	December 31, 2008	December 31, 2007	Notes
Regulatory Assets:	(in thousands)		
Noncurrent Regulatory Assets			
SFAS 158 Regulatory Asset (See Note 7)	$ 59,434	$ 25,867	(a) (e)
Unamortized Loss on Reacquired Debt	5,764	6,399	(b) (g)
Other	2,745	4,270	(a) (e)
Total Noncurrent Regulatory Assets	$ 67,943	$ 36,536	
Regulatory Liabilities:			
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Asset Removal Costs	$ 98,798	$ 92,151	(d)
Deferred Investment Tax Credits	13,989	15,039	(a) (f)
Excess Earnings	11,286	11,782	(b) (h)
SFAS 109 Regulatory Liability, Net (See Note 10)	6,392	8,694	(b) (e)
Other	557	473	(a) (e)
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 131,022	$ 128,139	

(a) Amount does not earn a return.
(b) Amount earns a return.
(c) A portion of this amount earns 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 44 years.
(g) Recovery/refund period – up to 12 years.
(h) Recovery/refund period – up to 23 years.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

TNC is subject to certain claims and legal actions arising in its ordinary course of business. In addition, TNC'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

TNC maintains insurance coverage normal and customary for an electric utility, subject to various deductibles. Insurance coverage includes all risks of physical loss or damage to assets, subject to insurance policy conditions and exclusions. Covered property generally includes power plants, substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. The insurance programs also generally provide coverage against loss arising from certain claims made by third parties and are in excess of TNC's retentions. Coverage is generally provided by a combination of a South Carolina domiciled insurance company, EIS, 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 net income, cash flows and financial condition.

COMMITMENTS

TNC has substantial construction commitments to support its operations and environmental investments. In managing the overall construction program and in the normal course of business, TNC contractually commits to third-party construction vendors for certain material purchases and other construction services. Budgeted construction expenditures for 2009 are $78.3 million. Budgeted construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital.

TNC purchases fuel, 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. Management does not expect to incur penalty payments under these provisions that would materially affect net income, cash flows or financial condition.

The following table summarizes TNC's actual contractual commitments at December 31, 2008:

Contractual Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
			(in millions)		
Construction Contracts for Capital Assets (a)	$ 17.3	$ 4.9	$ 6.0	$ -	$ 28.2

(a) Represents only capital assets that are contractual commitments.

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." In addition, TNC adopted FSP SFAS 133-1 and FIN 45-4 "Disclosures about Credit Derivatives and Certain Guarantees: An amendment of FSB Statement No. 133 and FASB Interpretation No. 45; and Clarification of the Effective Date of FASB Statement No. 161" effective December 31, 2008. There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties.

Indemnifications and Other Guarantees

Contracts

TNC 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, 2008, TNC entered into sale agreements including indemnifications with a maximum exposure of $3 million related to the sale price of certain generation assets in Texas. There are no material liabilities recorded for any indemnifications and the risk of payment/performance is remote.

Lease Obligations

TNC leases certain equipment under master lease agreements. See "Master Lease Agreements" section of Note 11 for disclosure of lease residual value guarantees.

CONTINGENCIES

Carbon Dioxide Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The dismissal of the lawsuit was appealed to the Second Circuit Court of Appeals. Briefing and oral argument concluded in 2006. In April 2007, the U.S. Supreme Court issued a decision holding that the Federal EPA has authority to regulate emissions of CO_2 and other greenhouse gases under the CAA, which may impact the Second Circuit's analysis of these issues. The Second Circuit requested supplemental briefs addressing the impact of the Supreme Court's decision on this case which were provided in 2007. Management believes the actions are without merit and intends to defend against the claims.

Alaskan Villages' Claims

In February 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in federal court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil & gas companies, a coal company, and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. The defendants filed motions to dismiss the action. The motions are pending before the court. Management believes the action is 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. TNC currently incurs costs to safely dispose of these substances.

Superfund addresses clean-up of hazardous substances that have been released to the environment. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. At December 31, 2008, TNC has been named potentially liable at one site under state law. In the instance where TNC 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 net income.

Management 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. TNC made an adjustment to its provision based on its ownership share. After mitigation by certain contractual rights, TNC's fuel expense decreased by $9.4 million.

Rail Transportation Litigation

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

FERC Long-term Contracts

In 2002, the FERC held a hearing related to a complaint filed by Nevada Power Company and Sierra Pacific Power Company (the Nevada utilities). The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were "high-priced." The complaint alleged that TNC 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 2006, the U.S. Court of Appeals for the Ninth Circuit reversed the FERC order and remanded the case to the FERC for further proceedings. That decision was appealed to the U.S. Supreme Court. In June 2008, the U.S. Supreme Court affirmed the validity of contractually-agreed rates except in cases of serious harm to the public. The U.S. Supreme Court affirmed the Ninth Circuit's remand on two issues, market manipulation and excessive burden on consumers. The FERC initiated remand procedures and gave the parties time to attempt to settle the issues. Management believes a provision recorded in 2008 should be sufficient. Management asserted claims against certain companies that sold power to TNC 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. Management is unable to predict the ultimate outcome of these proceedings or their impact on future net income and cash flows.

6. DISPOSITION

Texas Plants

In February 2008, TNC sold the mothballed Fort Phantom, Lake Pauline, Rio Pecos and San Angelo Plants for approximately $2.5 million to a nonaffiliated entity. In 2002, the book values of the plants and the land were impaired to $434 thousand. As part of the sale, the buyer assumed all environmental liabilities existing prior to and after the sale. As a result, the related ARO balances were reversed. Additionally, TNC recorded sales and related expenses and the impact of a settlement agreement with the City of San Angelo related to a purchase power contract between the City of San Angelo and TNC.

TNC also conveyed the Oak Creek Plant and related land at no cost to the City of Sweetwater. The plant and land assets were impaired to $89 thousand in 2002.

As a result of these dispositions, TNC recognized an immaterial loss in the first quarter of 2008.

7. BENEFIT PLANS

TNC participates in AEP sponsored qualified pension plans (merged at December 31, 2008) and unfunded nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. In addition, TNC participates in OPEB plans sponsored by AEP to provide medical and life insurance benefits for retired employees.

TNC adopted SFAS 158 in December 2006 and recognized the obligations associated with defined benefit pension plans and OPEB plans in its balance sheets. TNC recognizes an asset for a plan's overfunded status or a liability for a plan's underfunded status and recognizes, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. TNC records a SFAS 71 regulatory asset for qualifying SFAS 158 costs of regulated operations that for ratemaking purposes are deferred for future recovery. The effect of this standard on the 2006 financial statements was a pretax AOCI adjustment of $43.9 million that was partially offset by a SFAS 71 regulatory asset of $29.3 million and a deferred income tax asset of $5.1 million resulting in a net of tax AOCI equity reduction of $9.5 million.

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

The following tables provide a reconciliation of the changes in 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, 2008, and their funded status as of December 31 for each year:

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

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

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

Amounts Recognized on AEP's Balance Sheets as of December 31, 2008 and 2007

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

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

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

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

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

Pension and Other Postretirement Plans' Assets

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

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

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

	Target Allocation	Percentage of Plan Assets at Year End	
	2009	2008	2007
Asset Category			
Equity Securities	65%	53%	62%
Debt Securities	34%	43%	35%
Cash and Cash Equivalents	1%	4%	3%
Total	100%	100%	100%

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. AEP's investment policies prohibit the benefit trust funds from purchasing AEP securities (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies). However, AEP's investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law, including the Employee Retirement Income Security Act (ERISA).

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

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, 2008	December 31, 2007
Accumulated Benefit Obligation	**(in millions)**	
Qualified Pension Plans	$ 4,119	$ 3,914
Nonqualified Pension Plans	80	77
Total	$ 4,199	$ 3,991

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, 2008 and 2007 were as follows:

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

Actuarial Assumptions for Benefit Obligations

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

	Pension Plans		Other Postretirement Benefit Plans	
Assumptions	**2008**	**2007**	**2008**	**2007**
Discount Rate	6.00%	6.00%	6.10%	6.20%
Rate of Compensation Increase	5.90%(a)	5.90%(a)	N/A	N/A

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

N/A = Not Applicable

To determine a discount rate, 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 2008, the rate of compensation increase assumed varies with the age of the employee, ranging from 5% per year to 11.5% per year, with an average increase of 5.9%.

Estimated Future Benefit Payments and Contributions

Information about the 2009 expected cash flows for the pension (qualified and nonqualified) and OPEB plans is as follows:

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

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

The contribution to the pension plans is based on the minimum amount required by ERISA plus the amount to pay unfunded nonqualified benefits. The contribution to the OPEB plans is generally based on the amount of the OPEB plans' periodic benefit cost for accounting purposes as provided for in agreements with state regulatory authorities, plus the additional discretionary contribution of 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 OPEB are as follows:

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

Components of Net Periodic Benefit Cost

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

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

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

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

The following table provides TNC's net periodic benefit cost for the plans for the years ended December 31, 2008, 2007 and 2006:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2008	2007	2006	2008	2007	2006
	(in thousands)					
Benefit Cost	$ 360	$ 281	$ 1,303	$ 2,422	$ 2,523	$ 2,861

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

N/A = Not Applicable

The expected return on plan assets for 2008 was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation, and current prospects for economic growth.

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

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

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

	1% Increase	1% Decrease
	(in millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 20	$ (16)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	196	(163)

American Electric Power System Retirement Savings Plan

TNC participates in an AEP sponsored defined contribution retirement savings plan, the American Electric Power System Retirement Savings Plan, for substantially all employees. This qualified plan offers participants an opportunity to contribute a portion of their pay, includes features under Section 401(k) of the Internal Revenue Code and provides for company matching contributions. The matching contributions to the plan was 75% of the first 6% of eligible compensation contributed by the employee in 2008. Effective January 1, 2009, the match is 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions. The cost for contributions to the plan totaled $1.2 million in 2008, $1.1 million in 2007 and $1.1 million in 2006.

8. BUSINESS SEGMENTS

TNC has one reportable segment, a generation, transmission and distribution business. TNC's other activities are insignificant.

9. DERIVATIVES, HEDGING AND FAIR VALUE MEASUREMENTS

DERIVATIVES AND HEDGING

SFAS 133 requires recognition of all qualifying derivative instruments as either assets or liabilities in the statement of financial position at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes and supply and demand market data and assumptions. The fair values determined are reduced by the appropriate valuation adjustments for items such as discounting, liquidity and credit quality. Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to be less than or more than what the price should be based purely on supply and demand. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value 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 net income 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 Income on an accrual basis.

TNC'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), TNC 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. TNC 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 TNC's Consolidated Statements of Income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in Revenues or Expenses on the Consolidated Statements of Income depending on the relevant facts and circumstances.

Cash Flow Hedging Strategies

Prior to TNC's FERC-approved removal from the SIA and CSW Operating Agreement in 2006, TNC 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, TNC 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, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on the Consolidated Statements of Income, depending on the specific nature of the risk being hedged. TNC did not hedge all variable price risk exposure related to energy commodities. At various times during 2006, TNC recognized immaterial amounts in net income 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 at December 31, 2008:

	(in thousands)
Balance at December 31, 2005	$ (111)
Effective Portion of Changes in Fair Value	(703)
Impact Due to Changes in SIA	98
Reclasses from AOCI to Net Income	14
Balance at December 31, 2006	(702)
Effective Portion of Changes in Fair Value	702
Reclasses from AOCI to Net Income	-
Balance at December 31, 2007	-
Effective Portion of Changes in Fair Value	-
Reclasses from AOCI to Net Income	-
Balance at December 31, 2008	$ -

FAIR VALUE MEASUREMENTS

The fair values of Long-term Debt are based on quoted market prices for the same or similar issues and the current interest rates offered for instruments with similar maturities. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange. The book values and fair values of TNC's Long-term Debt at December 31, 2008 and 2007 are summarized in the following table:

	December 31, 2008		December 31, 2007	
	Book Value	**Fair Value**	**Book Value**	**Fair Value**
	(in thousands)			
Long-term Debt	$ 368,965	$ 340,971	$ 268,875	$ 271,815

10. INCOME TAXES

The details of income taxes as reported are as follows:

	Years Ended December 31, 2008	2007	2006
	(in thousands)		
Income Tax Expense (Credit):			
Current	$ 9,416	$ 21,948	$ 5,751
Deferred	5,386	(737)	(227)
Deferred Investment Tax Credits	(1,050)	(1,119)	(1,270)
Total Income Tax	$ 13,752	$ 20,092	$ 4,254

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,		
	2008	2007	2006
		(in thousands)	
Net Income	$ 33,916	$ 39,349	$ 14,943
Income Taxes	13,752	20,092	4,254
Pretax Income	$ 47,668	$ 59,441	$ 19,197
Income Tax on Pretax Income at Statutory Rate (35%)	$ 16,684	$ 20,804	$ 6,719
Increase (Decrease) in Income Tax resulting from the following items:			
Depreciation	(330)	(444)	(500)
Investment Tax Credits, Net	(1,050)	(1,119)	(1,270)
State and Local Income Taxes	(28)	1,010	(759)
Other	(1,524)	(159)	64
Total Income Taxes	$ 13,752	$ 20,092	$ 4,254
Effective Income Tax Rate	28.8%	33.8%	22.2%

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

	December 31,	
	2008	2007
	(in thousands)	
Deferred Tax Assets	$ 31,804	$ 39,651
Deferred Tax Liabilities	(157,843)	(162,225)
Net Deferred Tax Liabilities	$ (126,039)	$ (122,574)
Property Related Temporary Differences	$ (126,235)	$ (126,380)
Amounts Due from Customers for Future Federal Income Taxes	2,237	3,044
Deferred State Income Taxes	(1,306)	(1,184)
Deferred Income Taxes on Other Comprehensive Loss	8,704	5,012
Deferred Fuel and Purchased Power	-	812
Accrued Pensions	(1,678)	(11,076)
Provision for Refund	(5,212)	163
Regulatory Assets	(20,769)	(11,626)
All Other, Net	18,220	18,661
Net Deferred Tax Liabilities	$ (126,039)	$ (122,574)

TNC 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.

TNC and other AEP Subsidiaries are no longer subject to U.S. federal examination for years before 2000. TNC and other AEP Subsidiaries have completed the exam for the years 2001 through 2003 and have issues that are being 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, TNC 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 net income.

TNC, along with other AEP Subsidiaries, files income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns and TNC and other AEP Subsidiaries are currently under examination in several state and local jurisdictions. Management believes that TNC 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 net income. With few exceptions, TNC 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, TNC recorded interest and penalty expense related to uncertain tax positions in tax expense accounts. With the adoption of FIN 48 on January 1, 2007, TNC began recognizing interest accruals related to uncertain tax positions in interest income or expense as applicable, and penalties in Other Operation. The impact of this interpretation was an unfavorable adjustment to the 2007 opening balance of retained earnings of $557 thousand. In 2008, TNC reported $336 thousand of interest income and reversed $585 thousand of prior period interest expense. In 2007, TNC reported $156 thousand of interest expense and reversed $313 thousand of prior period interest expense. TNC had approximately $918 thousand for the receipt of interest accrued at December 31, 2008 and approximately $814 thousand and $816 thousand for the payment of interest and penalties accrued at December 31, 2008 and 2007, respectively.

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

	2008	2007
	(in thousands)	
Balance at January 1,	$ 5,597	$ 6,923
Increase - Tax Positions Taken During a Prior Period	52	-
Decrease - Tax Positions Taken During a Prior Period	(3,787)	(1,512)
Increase - Tax Positions Taken During the Current Year	863	188
Decrease - Tax Positions Taken During the Current Year	(180)	-
Decrease - Settlements with Taxing Authorities	-	(2)
Decrease - Lapse of the Applicable Statute of Limitations	-	-
Balance at December 31,	$ 2,545	$ 5,597

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $206 thousand and $2.6 million in 2008 and 2007, respectively. 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

Several tax bills and other legislation with tax-related sections were enacted in 2006 and 2007, including the Pension Protection Act of 2006, the Tax Relief and Health Care Act of 2006, the Tax Technical Corrections Act of 2007, the Tax Increase Prevention Act of 2007 and the Energy Independence and Security Act of 2007. The tax law changes enacted in 2006 and 2007 did not materially affect TNC’s net income, cash flows or financial condition.

The Economic Stimulus Act of 2008 was signed into law by the President in February 2008. It provided enhanced expensing provisions for certain assets placed in service in 2008 and a 50% bonus depreciation provision similar to the one in effect in 2003 through 2004 for assets placed in service in 2008. The enacted provisions did not have a material impact on net income or financial condition, but provided a material favorable cash flow benefit of approximately $6 million.

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

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

State Tax Legislation

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 reduced Texas income tax rates and was effective January 1, 2007. The new gross margin tax is income-based for purposes of the application of SFAS 109. Based on the new law, 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 TNC recorded decreases of $4.8 million in SFAS 109 Regulatory Assets, $1.3 million in state income tax expense and $6.1 million in deferred state income tax liabilities.

11. LEASES

Leases of property, plant and equipment are for periods up to 13 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:

	Years Ended December 31,		
	2008	2007	2006
Lease Rental Costs		(in thousands)	
Net Lease Expense on Operating Leases	$ 2,976	$ 3,137	$ 2,812
Amortization of Capital Leases	587	526	397
Interest on Capital Leases	46	93	82
Total Lease Rental Costs	$ 3,609	$ 3,756	$ 3,291

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

	December 31,	
	2008	2007
	(in thousands)	
Property, Plant and Equipment Under Capital Leases		
Total Property, Plant and Equipment Under Capital Leases – Other	$ 2,502	$ 2,189
Accumulated Amortization	1,413	893
Net Property, Plant and Equipment Under Capital Leases	$ 1,089	$ 1,296
Obligations Under Capital Leases		
Noncurrent Liability	$ 566	$ 748
Liability Due Within One Year	523	548
Total Obligations Under Capital Leases	$ 1,089	$ 1,296

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

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
2009	$ 540	$ 2,967
2010	352	2,585
2011	211	8,051
2012	9	401
2013	9	314
Later Years	-	388
Total Future Minimum Lease Payments	$ 1,121	$ 14,706
Less Estimated Interest Element	32	
Estimated Present Value of Future Minimum Lease Payments	$ 1,089	

Master Lease Agreements

TNC leases certain equipment under master lease agreements. GE Capital Commercial Inc. (GE) notified management in November 2008 that they elected to terminate the Master Leasing Agreements in accordance with the termination rights specified within the contract. In 2011, TNC will be required to purchase all equipment under the lease and pay GE an amount equal to the unamortized value of all equipment then leased. As a result, the unamortized value of this equipment of $6 million is reflected in TNC's future minimum lease payments for 2011. In December 2008, management signed new master lease agreements with one-year commitment periods that include lease terms of up to 10 years. Management expects to enter into replacement leasing arrangements for the equipment affected by this notification prior to the termination dates of 2011.

For equipment under the GE master lease agreements that expire prior to 2011, the lessor is guaranteed receipt of up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, TNC is committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. Under the new master lease agreements, the lessor is guaranteed receipt of up to 68% of the unamortized balance at the end of the lease term. If the actual fair market value of the leased equipment is below the unamortized balance at the end of the lease term, TNC is committed to pay the difference between the actual fair market value and unamortized balance, with the total guarantee not to exceed 68% of the unamortized balance. At December 31, 2008, the maximum potential loss for these lease agreements was approximately $743 thousand assuming the fair market value of the equipment is zero at the end of the lease term. Historically, at the end of the lease term the fair market value has been in excess of the unamortized balance.

12. FINANCING ACTIVITIES

Preferred Stock

Par Value	Authorized Shares	Shares Outstanding at December 31, 2008	Call Price at December 31, 2008 (a)	Series	Redemption	December 31, 2008	December 31, 2007
						(in thousands)	
$ 100	810,000	23,486	$ 107.00	4.40%	Any time	$ 2,349	$ 2,349

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

	Number of Shares Redeemed for the Years Ended December 31,		
Series	2008	2007	2006
4.40%	-	-	80

Long-term Debt

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

The following details long-term debt outstanding at December 31, 2008 and 2007:

Type of Debt	Maturity	Weighted Average Interest Rate at December 31, 2008	Interest Rate Ranges at December 31, 2008	Interest Rate Ranges at December 31, 2007	Outstanding at December 31, 2008	Outstanding at December 31, 2007
					(in thousands)	
Senior Unsecured Notes	2013-2038	5.81%	5.50%-6.76%	5.50%	$ 325,000	$ 225,000
Pollution Control Bonds (a)	2020	4.45%	4.45%	4.45%	44,310	44,310
Unamortized Discount					(345)	(435)
Long-term Debt					$ 368,965	$ 268,875

(a) Under the terms of the pollution control bonds, TNC 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. Interest rates are subject to periodic adjustment. Interest payments are made semi-annually. Letters of credit from banks, standby bond purchase agreements and insurance policies support certain series.

At December 31, 2008 future annual long-term debt payments are as follows:

	2009	2010	2011	2012	2013	After 2013	Total
				(in thousands)			
Principal Amount	$ -	$ -	$ -	$ -	$ 225,000	$ 144,310	$ 369,310
Unamortized Discount							(345)
Total Long-term Debt							$ 368,965

Money Pool – 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, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. The AEP System corporate borrowing program operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding borrowings from the Utility Money Pool and the Nonutility Money Pool are shown as either a net loan or a net borrowing position as of December 31, 2008 and 2007 and are included in Advances from Affiliates on TNC's balance sheets. TNC's Utility Money Pool activity and corresponding authorized borrowing limits for the years ended December 31, 2008 and 2007 are described in the following table:

Year	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Borrowings from Utility Money Pool as of December 31,	Authorized Short-Term Borrowing Limit
			(in thousands)			
2008	$ 88,094	$ 18,701	$ 42,176	$ 8,885	$ 40,660	$ 250,000
2007	59,565	3,200	32,020	2,365	50,795	250,000

The activity in the above table does not include short-term lending activity of TNC's wholly-owned subsidiary, AEP Texas North Generation Company LLC (TNGC), who is a participant in the Nonutility Money Pool. For the years ended December 31, 2008 and 2007, TNGC had the following activity in the Nonutility Money Pool:

Year	Maximum Borrowings from Nonutility Money Pool	Maximum Loans to Nonutility Money Pool	Average Borrowings from Nonutility Money Pool	Average Loans to Nonutility Money Pool	Loans to Nonutility Money Pool as of December 31,
			(in thousands)		
2008	$ -	$ 18,656	$ -	$ 17,479	$ 11,974
2007	-	20,152	-	16,033	17,284

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool for the years ended December 31, 2008, 2007 and 2006 are summarized in the following table:

Years Ended December 31,	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
2008	5.47%	2.28%	3.41%	2.91%	3.88%	3.08%
2007	5.94%	5.16%	5.35%	5.34%	5.43%	5.35%
2006	5.41%	3.32%	5.22%	3.83%	4.60%	4.56%

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Nonutility Money Pool for the years ended December 31, 2008 and 2007 are summarized in the following table:

Years Ended December 31,	Maximum Interest Rates for Funds Borrowed from the Nonutility Money Pool	Minimum Interest Rates for Funds Borrowed from the Nonutility Money Pool	Maximum Interest Rates for Funds Loaned to the Nonutility Money Pool	Minimum Interest Rates for Funds Loaned to the Nonutility Money Pool	Average Interest Rates for Funds Borrowed from the Nonutility Money Pool	Average Interest Rates for Funds Loaned to the Nonutility Money Pool
2008	-%	-%	5.47%	2.28%	-%	3.52%
2007	-%	-%	5.94%	5.16%	-%	5.45%

Interest expense and interest income related to the Utility Money Pool are included in Interest Expense and Interest Income, respectively, in TNC's Consolidated Statements of Income. For amounts borrowed from and advanced to the Utility Money Pool, TNC incurred the following amounts of interest expense and earned the following amounts of interest income, respectively, for the years ended December 31, 2008, 2007 and 2006:

	Years Ended December 31, 2008	2007	2006
		(in thousands)	
Interest Expense	$ 1,146	$ 1,747	$ 274
Interest Income	87	1	112

Interest expense and interest income related to the Nonutility Money Pool are included in Interest Expense and Interest Income, respectively, in TNC's Consolidated Statements of Income. For amounts borrowed from and advanced to the Nonutility Money Pool, TNC incurred the following amounts of interest expense and earned the following amounts of interest income, respectively, for the years ended December 31, 2008 and 2007:

	Years Ended December 31, 2008	2007
	(in thousands)	
Interest Expense	$ -	$ -
Interest Income	627	880

Dividend Restrictions

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

Credit Facilities

In April 2008, TNC and certain other companies in the AEP System entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement which were reduced by Lehman Brothers Holdings Inc.'s commitment amount of $23 million and $12 million, respectively, following its bankruptcy. Under the facilities, letters of credit may be issued. As of December 31, 2008, there were no outstanding amounts for TNC under either facility.

13. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "Money Pool – AEP System" section of Note 12.

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 these two companies as parties to the SIA. 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)

The SIA provides for the integration and coordination of AEP East companies and AEP 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 a 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, TNC is no longer a party to the SIA.

Power generated, allocated or provided under the Interconnection Agreement or CSW Operating Agreement to TNC was 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 and Purchases

The following table shows the revenues derived from direct sales to affiliates and other revenues for the years ended December 31, 2008, 2007 and 2006:

	Years Ended December 31,		
	2008	2007	2006
Related Party Revenues		(in thousands)	
Direct Sales to West Affiliates	$ -	$ -	$ 17
Direct Sales to AEPEP Affiliate	94,060	92,591	-
Other	6,463	3,806	33,208
Total Revenues	$ 100,523	$ 96,397	$ 33,225

The following table shows the purchased power expense incurred from purchases from the pool and affiliates for the years ended December 31, 2008, 2007 and 2006:

	Years Ended December 31,		
	2008	2007	2006
Related Party Purchases		(in thousands)	
Purchases from West System Pool	$ -	$ -	$ 4
Direct Purchases from East Affiliates	-	-	11
Direct Purchases from West Affiliates	-	739	5,933
Total Purchases	$ -	$ 739	$ 5,948

The above summarized related party revenues and expenses are reported as Sales to AEP Affiliates and Purchased Electricity for Resale on TNC's Consolidated Statements of Income.

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 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. The 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).

TNC's net credits allocated under the TCA pursuant to the ERCOT protocols as described above during the years ended December 31, 2008, 2007 and 2006 were $1.5 million, $1.1 million and $1 million, respectively.

The net credits are recorded in Other Operation on TNC's Consolidated Statements of Income.

Assignment from SWEPCo, TCC and TNC to AEPEP

On March 1, 2008, SWEPCo, TCC and TNC assigned a 20-year Purchase Power Agreement (PPA) to AEPEP. In addition to the PPA assignment, an intercompany agreement was executed between AEPEP and SWEPCo to provide SWEPCo with future margins related to its share. The PPA and intercompany agreements are effective through 2019.

Oklaunion PPA between TNC and AEP Energy Partners

On January 1, 2007, TNC began a 20-year Power Purchase & Sale Agreement (PPA) with an affiliate, AEP Energy Partners (AEPEP), whereby TNC agrees to sell AEPEP 100% of TNC's capacity and associated energy from its undivided interest (54.69%) in the Oklaunion Plant. AEPEP is to pay TNC for the capacity and associated energy delivered to the delivery point, the sum of fuel, operation and maintenance, depreciation, capacity and all taxes other than federal income taxes applicable. A portion of the payment is fixed and is payable regardless of the level of output. There are no penalties if TNC fails to maintain a minimum availability level or exceeds a maximum heat rate level. The PPA was approved by the FERC on July 12, 2006. TNC recognizes revenues for the fuel, operations and maintenance and all other taxes on an as-billed basis. Revenue is recognized for the capacity and depreciation billed to AEPEP, on a straight-line basis over the term of the PPA as these represent the minimum payments due.

TNC recorded revenue of $94 million and $93 million from AEPEP for the years ended December 31, 2008 and 2007, respectively. These amounts are included in Sales to AEP Affiliates on TNC's 2008 and 2007 Consolidated Statements of Income.

SPP Customers and Assets Transferred from TNC to SWEPCo

SWEPCo's and approximately 3% of TNC's businesses were in SPP. A petition was filed in May 2006 requesting approval to transfer Mutual Energy SWEPCO L.P.'s (a subsidiary of AEP C&I Company, LLC) customers and TNC's facilities and certificated service territory located in the SPP area to SWEPCo. In January 2007, the final regulatory approval was received for the transfers. The transfers were effective February 2007 and were recorded at net book value of $12 million.

Jointly-Owned Electric Utility Plant

PSO and TNC jointly own the Oklaunion Plant along with two nonaffiliated companies. TCC sold its share to one of the nonaffiliated companies 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 statements. TNC's investment in this plant is included in Property, Plant and Equipment on its Consolidated Balance Sheets.

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. TNC's purchases from Sweeny were $4.2 million for the year ended December 31, 2006. This amount is recorded in Purchased Electricity for Resale on TNC's 2006 Consolidated Statement of Income.

Sales and Purchases of Property

TNC had affiliated sales and purchases of electric property individually amounting to $100 thousand or more for the years ended December 31, 2008, 2007 and 2006 as shown in the following table:

	Years Ended December 31,		
	2008	2007	2006
Companies		(in thousands)	
TNC to SWEPCo	$ -	$ 11,649	$ -
TNC to TCC	-	2,300	-

In addition, TNC had aggregate affiliated sales and purchases of meters and transformers for the years ended December 31, 2008, 2007 and 2006 as shown in the following table:

	I&M	OPCo	PSO	SWEPCo	TCC	Total
Sales			(in thousands)			
2008	$ -	$ 9	$ 28	$ 26	$ 334	$ 397
2007	1	-	10	456	199	666
2006	-	-	17	4	209	230
Purchases						
2008	$ -	$ 11	$ 25	$ 9	$ 494	$ 539
2007	-	-	2	13	763	778
2006	-	-	2	-	1,266	1,268

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

Intercompany Billings

TNC 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.

Variable Interest Entities

FIN 46R is a consolidation model that considers risk absorption of a variable interest entity (VIE), also referred to as variability. Entities are required to consolidate a VIE when it is determined that they are the primary beneficiary of that VIE, as defined by FIN 46R. In determining whether TNC is the primary beneficiary of a VIE, management considers factors such as equity at risk, the amount of variability of the VIE TNC absorbs, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE and other factors. Management believes that the significant assumptions and judgments were applied consistently and that there are no other reasonable judgments or assumptions that would result in a different conclusion. There have been no changes to the reporting of VIEs in the financial statements where it is concluded that TNC is the primary beneficiary. In addition, TNC has not provided financial or other support that was not previously contractually required to any VIE.

As of December 31, 2008, TNC holds a significant variable interest in AEPSC. AEPSC provides certain managerial and professional services to TNC. AEP is the sole equity owner of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to TNC at AEPSC's cost. TNC has not provided financial or other support outside the reimbursement of costs for services rendered. The cost reimbursement nature of AEPSC finances its operations. There are no other terms or arrangements between AEPSC and TNC that could require additional financial support from TNC or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. TNC is exposed to losses to the extent it cannot recover the costs of AEPSC through its normal business operations. TNC is considered to have a significant interest in the variability of AEPSC due to its activity in AEPSC's cost reimbursement structure. AEPSC is consolidated by AEP. In the event

AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. Total billings from AEPSC for the years ended December 31, 2008 and 2007 were $34.8 million and $30.3 million, respectively. The carrying amount of liabilities associated with AEPSC for the years ended December 31, 2008 and 2007 were $3.9 million and $4.4 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

14. PROPERTY, PLANT AND EQUIPMENT

Depreciation

TNC 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:

2008	**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)**
Production	$ -	$ -	-	-	$ 295,065	$ 135,754	2.6%	20-49
Transmission	411,839	99,549	2.6%	45-75	-	-	-	-
Distribution	548,424	146,560	3.5%	28-70	-	-	-	-
CWIP	76,779	(2,534)	N.M.	N.M.	5,504	-	N.M.	N.M.
Other	103,343	75,807	9.1%	N.M.	4,501	3,732	N.M.	N.M.
Total	$ 1,140,385	$ 319,382			$ 305,070	$ 139,486		

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)**
Production	$ -	$ -	-	-	$ 292,109	$ 129,690	2.6%	20-49
Transmission	344,100	93,092	3.0%	45-75	239	86	N.M.	N.M.
Distribution	523,248	143,980	3.4%	28-70	-	-	-	-
CWIP	65,399	1,459	N.M.	N.M.	1,362	168	N.M.	N.M.
Other	88,763	61,886	6.6%	N.M.	71,731	68,229	N.M.	N.M.
Total	$ 1,021,510	$ 300,417			$ 365,441	$ 198,173		

2006	**Regulated**		**Nonregulated**	
Functional Class of Property	**Annual Composite Depreciation Rate Ranges**	**Depreciable Life Ranges**	**Annual Composite Depreciation Rate Ranges**	**Depreciable Life Ranges**
		(in years)		**(in years)**
Production	-	-	9.2%	20-49
Transmission	2.9%	40-75	-	-
Distribution	3.2%	19-55	-	-
Other	9.3%	N.M.	N.M.	N.M.

N.M. = Not Meaningful

For cost-based rate-regulated operations, 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. For nonregulated operations, non-ARO removal cost is expensed as incurred.

Asset Retirement Obligations (ARO)

TNC records ARO in accordance with SFAS 143 "Accounting for Asset Retirement Obligations" and FIN 47 "Accounting for Conditional Asset Retirement Obligations" for asbestos removal. TNC 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 TNC plans to use its facilities indefinitely. The retirement obligation would only be recognized if and when TNC abandons or ceases the use of specific easements, which is not expected.

The following is a reconciliation of the 2008 and 2007 aggregate carrying amounts of ARO for TNC:

Year	ARO at January 1,	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO at December 31,
			(in thousands)			
2008	$ 10,659	$ 388	$ -	$ (5,535)	$ 52	$ 5,564
2007	14,868	937	13	(821)	(4,338)	10,659

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

TNC's amounts of allowance for borrowed and equity funds used during construction are summarized in the following table:

	Years Ended December 31, 2008	2007	2006
		(in thousands)	
Allowance for Equity Funds Used During Construction	$ 1,901	$ 265	$ 886
Allowance for Borrowed Funds Used During Construction	1,945	1,412	568

Jointly-owned Electric Utility Plant

TNC has a 54.7% ownership share of Unit No. 1 at the Oklaunion Generating Station. In addition to TNC, the Oklaunion Generating Station is jointly-owned by PSO and various nonaffiliated companies. Each of the participating companies is obligated to pay its share of the costs in the same proportion as its ownership interest. TNC's proportionate share of the operating costs associated with this facility is included in its Consolidated Statements of Income and the investment and accumulated depreciation are reflected in its Consolidated Balance Sheets under Property, Plant and Equipment at December 31, 2008 and 2007 as follows:

	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
TNC's Share at December 31, 2008				(in thousands)	
Oklaunion Generating Station (Unit No. 1) (a)	Coal	54.7%	$ 295,065	$ 5,389	$ 135,752
TNC's Share at December 31, 2007					
Oklaunion Generating Station (Unit No. 1) (a)	Coal	54.7%	$ 292,109	$ 1,314	$ 129,641

(a) Operated by PSO.

15. 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 net income for interim periods. Quarterly results are not necessarily indicative of a full year's operations because of various factors. TNC's unaudited quarterly financial information is as follows:

	2008 Quarterly Periods Ended			
	March 31	**June 30**	**September 30**	**December 31**
	(in thousands)			
Revenues	$ 64,218	$ 65,629	$ 71,603	$ 76,336 (a)
Operating Income	11,601	14,745	18,043	13,831 (a)
Net Income	5,125	7,230	11,688	9,873 (a)

	2007 Quarterly Periods Ended			
	March 31	**June 30**	**September 30**	**December 31**
	(in thousands)			
Revenues	$ 62,963	$ 73,880	$ 79,447	$ 63,935
Operating Income	11,668	19,371	36,288	6,675
Net Income	5,277	10,124	21,549	2,399

(a) See "Allocation of Off-system Sales Margins" section of Note 3 for discussion of the financial statement impact of the FERC's November 2008 order related to the SIA.

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