TU ELECTRIC

Log # TXX-94106
File # 10045
841.1
Ref. # 10CFR50.71(b)

William J. Cahill, Jr.
Group Vice President

April 6, 199~~3~~4

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555

SUBJECT: COMANCHE PEAK STEAM ELECTRIC STATION (CPSES)
DOCKET NOS. 50-445 AND 50-446
SUBMITTAL OF SECURITIES AND EXCHANGE COMMISSION
ANNUAL REPORT FORM 10K

Gentlemen:

Pursuant to 10CFR50.71(b), TU Electric hereby submits five (5) copies of the Form 10K Annual Report.

Sincerely,

William J. Cahill, Jr.

By: J S Marshall
J. S. Marshall
Generic Licensing Manager

JDR/
Enclosures

c - Mr. L. J. Callan, Region IV (clo)
Resident Inspectors, CPSES (clo)
Mr. T. A. Bergman, NRR (clo)

M004 1/5

400 N. Olive Street L.B. 81 Dallas, Texas 75201

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

Form 10-K

[✓] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended December 31, 1993

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission File Number 0-11442

Texas Utilities Electric Company

(Exact name of registrant as specified in its charter)

A Texas Corporation

I.R.S. Employer No. 75-1837355

2001 Bryan Tower, Dallas, Texas 75201
Telephone Number (214) 812-4600

Securities Registered Pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Depositary Shares, each representing ¼ of a share of $8.20 Cumulative Preferred Stock, without par value.	New York Stock Exchange, Inc.
Depositary Shares, Series A, each representing ¼ of a share of $7.50 Cumulative Preferred Stock, without par value.	New York Stock Exchange, Inc.
Depositary Shares, Series B, each representing ¼ of a share of $7.22 Cumulative Preferred Stock, without par value.	New York Stock Exchange, Inc.

Securities Registered Pursuant to Section 12(g) of the Act: Preferred Stock, without par value

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ✓ No ___

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [✓]

Aggregate market value of Common Stock on February 28, 1994 held by non-affiliates: None

Common Stock outstanding at February 28, 1994: 152,000,000 shares, without par value

DOCUMENTS INCORPORATED BY REFERENCE
None

TABLE OF CONTENTS

PART I

Item 1. BUSINESS.

THE COMPANY

Texas Utilities Electric Company (Company) was incorporated under the laws of the State of Texas in 1982 and has perpetual existence under the provisions of the Texas Business Corporation Act. The Company is an electric utility engaged in the generation, purchase, transmission, distribution and sale of electric energy wholly within the State of Texas. The Company possesses all of the necessary franchises and certificates required to enable it to conduct its business (see Regulation and Rates).

The Company is the principal subsidiary of Texas Utilities Company (Texas Utilities). The other electric utility of Texas Utilities is Southwestern Electric Service Company (SESCO), which is engaged in the purchase, transmission, distribution, and sale of electric energy in ten counties in the eastern and central parts of Texas with a population estimated at 125,000. Texas Utilities also has three other subsidiaries which perform specialized functions within the Texas Utilities Company system: Texas Utilities Fuel Company (Fuel Company) owns a natural gas pipeline system, acquires, stores and delivers fuel gas and provides other fuel services at cost for the generation of electric energy by the Company; Texas Utilities Mining Company (Mining Company) owns, leases and operates fuel production facilities for the surface mining and recovery of lignite at cost for use at the Company's generating stations; and Texas Utilities Services Inc. (TU Services) provides financial, accounting, computer, telecommunications, personnel, procurement and other administrative services at cost. TU Services also acts as transfer agent, registrar and dividend paying agent with respect to the preferred stock of the Company. Texas Utilities and its subsidiaries are referred to herein as "System Companies."

The Company's service area covers the north central, eastern and western parts of Texas, with a population estimated at 5,650,000 — about one-third of the population of Texas. Electric service is provided in 88 counties and 372 incorporated municipalities, including Dallas, Fort Worth, Arlington, Irving, Plano, Waco, Mesquite, Grand Prairie, Wichita Falls, Odessa, Midland, Carrollton, Tyler, Richardson and Killeen. The area is a diversified commercial and industrial center with substantial banking, insurance, communications, electronics, aerospace, petrochemical and specialized steel manufacturing, and automotive and aircraft assembly. The territory served includes major portions of the oil and gas fields in the Permian Basin and East Texas, as well as substantial farming and ranching sections of the State. It also includes the Dallas-Fort Worth International Airport and the Alliance Airport. For energy sales and operating revenues contributed by each customer classification, see Item 6. Selected Financial Data — Operating Statistics.

At December 31, 1993, the Company had 7,674 full-time employees.

PEAK LOAD AND CAPABILITY

The Company's net capability, peak load and reserve, in megawatts (MW), at the time of peak were as follows during the years indicated:

Year	Net Capability	Peak Load (a) Amount	Peak Load (a) Increase (Decrease) Over Prior Year	Firm Peak Load	Reserve(b)
1993	21,697(c)	18,324	4.6%	17,852	3,845
1992	21,697	17,525	3.4	17,102	4,595
1991	21,849	16,952	(5.9)	16,831	5,018

(a) The 1993 peak load occurred on July 29. The Company peak load includes interruptible load at the time of peak of 499 MW in 1993, 463 MW in 1992 and 341 MW in 1991.

(b) Amount of net capability in excess of firm peak load at the time of peak.

(c) Included in net capability was 1,771 MW of firm purchased capacity, including 1,691 MW of cogeneration and small power production. Excluded from net capability was Comanche Peak Unit 2 (1,150 MW), which was placed into commercial operation after the peak load occurred.

The peak load changes resulted primarily from customer growth in the service area and weather factors. The Company expects to continue to purchase capacity in the future from various sources. (See Fuel Supply and Purchased Power and Note 12 to Financial Statements.)

On November 14, 1993, the emissions chimney serving Unit 3 (750 MW) of the Monitcello lignite-fueled generating station (Monticello) collapsed, rendering the unit inoperable. The unit will be rebuilt and operated as a lignite/coal-fueled facility. The Company expects the unit to be returned to service during 1995. (See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation — Liquidity and Capital Resources.)

Firm peak load increases over the next ten years are expected to average approximately 2.2% annually, after giving effect to load management programs (including interruptible contracts). The Company's ten year system resource plan (Resource Plan) provides for meeting the increases in required net capability through the completion of gas/oil-fueled combustion turbine and lignite-fueled capacity additions, purchased power capacity (including cogeneration and small power production) and load management programs. Load management programs are designed to improve the efficient use of the Company's generating units and help delay the need to add new capacity. The Resource Plan is subject to annual review as part of a regular planning process. When compared to the previous resource plan, the current plan reflects a one year deferral for the in-service dates of 1,500 MW of Twin Oak lignite units (Twin Oak), 1,230 MW of combined cycle combustion turbines and 272 MW of simple-cycle combustion turbines. The components of the Resource Plan (see Item 2. Properties — Construction Program) are as follows:

PEAK LOAD AND CAPABILITY — (Concluded)

Resource Additions	Resource Plan 1994-2003 Capability (MW)	Percent
Combustion Turbines	1,502	28%
Lignite/Coal	1,500	28
Load Management	1,228	22
Purchased Power	1,189	22
Total	5,419	100%

The Company is currently conducting an experimental pilot project, in conjunction with regulatory and customer groups, to develop a 1995 Integrated Resource Plan (IRP). In addition to increasing public participation in the planning process, the Company is soliciting proposals for additional demand-side management resources and certain renewable energy resources to meet a portion of the customers' future energy requirements. The IRP is expected to be completed and filed with the Public Utility Commission of Texas (PUC) late in the summer of 1994. The Company hopes to obtain approval of the IRP in early 1995. It is unknown what effect, if any, this new planning process will have on future resource plans.

FUEL SUPPLY AND PURCHASED POWER

Net input for 1993 was 91,537 million kilowatt-hours (kWh) of which 79,105 million kWh were generated by the Company. During this period, 844,128,889 million British thermal units (Btu) of fuel (including 40,391,702 million Btu furnished by Aluminum Company of America (Alcoa) at no cost) were consumed for electric generation (see Lignite/Coal).

Average fuel and purchased power cost (excluding capacity charges) per kWh of net input was 1.92 cents for 1993, 1.85 cents for 1992 and 1.82 cents for 1991. A comparison of the resource mix for net kWh input and the unit cost per million Btu of fuel to the Company during the last three years is as follows:

	Mix for Net kWh Input			Unit Cost Per Million Btu		
	1993	1992	1991	1993	1992	1991
Fuel for Electric Generation:						
Gas/Oil(a)	33.7%	34.4%	37.4%	$2.81	$2.69	$2.47
Lignite/Coal(b)	40.3	44.2	43.9	1.10	1.05	1.05
Nuclear	12.4	8.1	6.1	0.71(c)	0.41	0.33
Total/Weighted Average Fuel Cost	86.4	86.7	87.4	$1.73	$1.65	$1.62
Purchased Power	13.6	13.3	12.6			
Total	100.0%	100.0%	100.0%			

(a) Fuel oil amounted to 0.003% in 1993, and 0.02% in 1992 and 0.1% in 1991 of total fuel and purchased power requirements.
(b) Lignite cost per ton to the Company was $ 13.98 in 1993, $13.19 in 1992 and $13.48 in 1991.
(c) Unit cost per million Btu in 1993 includes avoided cost of fuel during trial operations. The 1993 cost, excluding Comanche Peak Unit 2 while in trial operation, was $0.62 in 1993.

FUEL SUPPLY AND PURCHASED POWER — (Continued)

Gas/Oil

Fuel gas for units at nineteen of the principal generating stations of the Company, having an aggregate net gas/oil capability of 12,931 MW, was provided during 1993 by Fuel Company. Fuel Company supplied approximately 48% of such fuel gas requirements under contracts with producers at the wellhead and under other contracts with dedicated reserves and 52% under contracts with commercial suppliers. Additional gas/oil-fueled combustion turbines, with an aggregate net capability of 1,502 MW, are planned for the future (see Peak Load and Capability and Item 2. Properties — Construction Program).

Fuel Company has acquired under contracts expiring at intervals through 2008, with producers at the wellhead, supplies of gas which are generally expected to be produced over a ten to fifteen year period. As gas production under contract declines and contracts expire, new contracts are expected to be negotiated to replenish or augment such supplies. Fuel Company has negotiated gas purchase contracts, with terms ranging from one to twenty years, with a number of commercial suppliers. Additionally, Fuel Company has entered into a number of short-term gas purchase contracts with other commercial suppliers at spot market prices; however, these contracts typically do not provide for a firm supply obligation from the seller or a firm purchase obligation from Fuel Company. In the past, curtailments of gas deliveries have been experienced during periods of winter peak gas demand; however, such curtailments have been of relatively short duration, have had minimal impact on operations and have generally required utilization of fuel oil and gas storage inventories to replace the gas curtailed. During 1993, no curtailments were experienced.

Fuel Company owns and operates an intrastate natural gas pipeline system which extends from the gas-producing area of the Permian Basin in West Texas to the East Texas gas fields and southward to the Gulf Coast area. This system includes a one-half interest in a 36-inch pipeline which extends 395 miles from the Permian Basin area of West Texas to a point of termination south of the Dallas-Fort Worth area and has a total estimated capacity of 800 million cubic feet per day with existing compression facilities. Additionally, Fuel Company owns a 39% undivided interest in another 36-inch pipeline, connecting to this pipeline and extending 58 miles eastward to one of Fuel Company's underground gas storage facilities. Fuel Company also owns and operates approximately 1,650 miles of various smaller capacity lines which are used to gather and transport natural gas from other gas-producing areas. The pipeline facilities of Fuel Company form an integrated network through which fuel gas is gathered and transported to certain generating stations of the Company for use in the generation of electric energy.

Fuel Company also owns and operates three underground gas storage facilities with a usable capacity of 27.2 billion cubic feet with approximately 20.2 billion cubic feet of gas in inventory at December 31, 1993. Gas stored in these facilities currently can be withdrawn for use during periods of peak demand, to meet seasonal and other fluctuations or curtailment of deliveries by gas suppliers. Under normal operating conditions, up to 500 million cubic feet can be withdrawn each day for a two-week period, with withdrawals at lower rates thereafter.

Fuel oil is stored at all nineteen of the principally gas-fueled generating stations. At December 31, 1993, the System Companies had fuel oil storage capacity sufficient to accommodate approximately 6.6 million barrels of oil, with approximately 2.4 million barrels of oil in inventory. Fuel Company has access to an oil pipeline and owns a terminal facility to provide for more dependable and efficient movement of oil. Generally, oil required to replenish that oil removed from storage will be obtained through purchases in the open market.

Lignite/Coal

Lignite is used as the primary fuel in two units in service at the Big Brown generating station (Big Brown), three units at Monticello, three units at the Martin Lake generating station (Martin Lake) and one unit at the Sandow generating station (Sandow), having an aggregate net capability of 5,845 MW. Two other lignite-fueled units, with an aggregate net capability of 1,500 MW, are included in the current Resource Plan (see Peak Load and Capability and Item 2. Properties — Construction Program). The Company's lignite units have been constructed adjacent to surface mined lignite reserves. At the present time, the Company owns in fee or has under lease an estimated 863 million tons of proven reserves dedicated to existing power plants or planned future power plants. Mining Company owns, leases and operates equipment to remove the overburden and to recover lignite. One of the Company's lignite units, Sandow 4, is fueled from lignite deposits owned by Alcoa, which furnishes fuel at no cost to the Company for that portion of energy generated from such unit which is equal to the amount of energy delivered to Alcoa (see Item 6. Selected Financial Data — Operating Statistics).

Lignite production operations at Big Brown, Monticello and Martin Lake are accompanied by an extensive reclamation program which returns the land to productive uses such as wildlife habitats, commercial timberland and pasture land. Similar programs are planned for future lignite-fueled production operations. For information concerning federal and state laws with respect to surface mining, see Environmental Matters.

The Company supplemented Company-owned lignite fuel at its Monticello plant with western coal from the Powder River Basin (PRB) in Wyoming during five months of 1993. The coal was purchased and transported on an "as-available, as-required" basis. Because current mine capacity in the PRB is greater than the demand at this time, ample amounts of western coal are available on the spot market at favorable prices. Fuel requirements at Monticello were reduced as a result of the November 1993 collapse of the emissions chimney at Unit 3. Consequently, deliveries of western coal were discontinued and lignite mining operations at the Monticello mines were reduced. When Unit 3 returns to service, lignite mining operations and western coal deliveries at Monticello will resume in order to supply the required fuels. Further, the Company is also actively considering the use of western coal as a supplemental fuel at its other existing lignite-fueled plants and as a long-term alternative fuel for existing and future units. For information concerning applicable air quality standards, see Environmental Matters.

Nuclear

The Company owns and operates two nuclear-fueled generating units at the Comanche Peak nuclear generating station (Comanche Peak), each of which is designed for a net capability of 1,150 MW. (See Peak Load and Capability.)

FUEL SUPPLY AND PURCHASED POWER — (Continued)

The nuclear fuel cycle requires the mining and milling of uranium ore to provide uranium oxide concentrate (U_3O_8), the conversion of U_3O_8 to uranium hexafluoride (UF_6), the enrichment of the UF_6 and the fabrication of the enriched uranium into fuel assemblies. The Company has on hand or has contracted for the raw materials and services it expects to need for its nuclear units through the years shown below:

Uranium	Conversion	Enrichment	Fabrication
2001	2003	2014	2002

The Company expects to meet its U_3O_8 requirements through the years shown above from inventory on hand and amounts under contract. Although the Company cannot predict the future availability of uranium and nuclear fuel services, the Company does not currently expect to have difficulty obtaining U_3O_8 and the services necessary for its conversion, enrichment and fabrication into nuclear fuel for years later than those shown above.

The National Energy Policy Act of 1992 (Energy Act) has provisions for the recovery of a portion of the costs associated with the decommissioning and decontamination of the gaseous diffusion plants used to enrich uranium for fuel. These costs are being recovered in fees paid to the Department of Energy as determined by the Secretary of Energy. The total annual assessment for all domestic utilities is capped at $150 million per federal fiscal year assessable for fifteen years. The Company's share, as established by the Department of Energy, is estimated to be $1.3 million per year.

The Nuclear Waste Policy Act of 1982, as amended (NWPA), provides for the development by the federal government of interim storage and permanent disposal facilities for spent nuclear fuel and/or high level radioactive waste materials. The Company is unable to predict when the federal government will be able to provide such storage and disposal facilities. Under provisions of the NWPA, funding for the program is provided by a one-mill per kWh fee currently levied on electricity generated and sold from nuclear reactors, including the Comanche Peak units. Onsite storage capacity for spent fuel is sufficient to accommodate the operation of Comanche Peak for approximately 10 years and this storage capacity can be increased, subject to approval by the Nuclear Regulatory Commission (NRC).

Purchased Power

In 1993, the Company purchased 12,432 million kWh or approximately 14% of its energy requirements and had available 1,771 MW of firm purchased capacity, or approximately 8%, of net capability under contract at the time of peak load. The Company may acquire purchased power capacity in the future to accommodate a portion of system load and continues to investigate potential available sources. For information concerning the Resource Plan, see Peak Load and Capability and Note 12 to Financial Statements.

General

The Company is not able to predict: (i) whether or not problems may be encountered in the future in obtaining the fuel and purchased power it will require, (ii) the effect upon its operations of any difficulty it may experience in protecting its rights to fuel and purchased power now under contract,

FUEL SUPPLY AND PURCHASED POWER — (Concluded)

or (iii) the cost of fuel and purchased power. All reasonable costs of fuel and purchased power are generally recoverable subject to the rules of the PUC. (See Regulation and Rates for information pertaining to the method of recovery of purchased power and fuel costs.)

REGULATION AND RATES

Regulation

Texas Utilities and its subsidiaries, including the Company, are exempt from the provisions of the Public Utility Holding Act of 1935, except Section 9(a)(2) which relates to the acquisition of securities of public utility companies.

The Company does not transmit electric energy in interstate commerce or sell electric energy at wholesale in interstate commerce, or own or operate facilities therefor, and its facilities are not connected directly or indirectly to other systems which are involved in such interstate activities, except during the continuance of emergencies permitting temporary or permanent connections or under order of the Federal Energy Regulatory Commission (FERC) exempting the Company from jurisdiction under the Federal Power Act. In view thereof, the Company believes that it is not a public utility as defined in the Federal Power Act and has been advised by its counsel that it is not subject to general regulation under such Act.

The PUC has original jurisdiction over electric rates and service in unincorporated areas and those municipalities that have ceded original jurisdiction to the PUC and has exclusive appellate jurisdiction to review the rate and service orders and ordinances of municipalities. Generally, the Texas Public Utility Regulatory Act prohibits the collection of any rates or charges (including charges for fuel) by a public utility that does not have the prior approval of the PUC. The provisions for inclusion of construction work in progress (CWIP) in rate base provide that such inclusion is an exceptional form of rate relief to be granted only when necessary to the financial integrity of the utility and that it shall not be included for major projects to the extent they have been imprudently planned or managed.

The construction of new production facilities of the Company is subject to PUC certification. In January 1992, the PUC approved Notice of Intent (NOI) applications which were filed by the Company in June 1991 for 1,512 MW of combustion turbines and 650 MW of coal-fired generation. An NOI is the first step of a process for PUC approval for construction of utility plant. Certain intervenors in the NOI proceeding appealed the PUC's approval. On November 23, 1993, the 126th Judicial District Court of Travis County, Texas announced its decision to reverse and remand the PUC's approval; however, the court has not yet issued a judgment. The Company will decide about an appeal after the judgment is issued. (See Peak Load and Capability and Item 2. Properties — Construction Program.)

The Company is subject to the jurisdiction of the NRC with respect to nuclear power plants. NRC regulations govern the granting of licenses for the construction and operation of nuclear power plants and subject such plants to continuing review and regulation.

REGULATION AND RATES — (Continued)

In August 1992, following action by the NRC staff which extended the construction permit for Comanche Peak Unit 2, an Atomic Safety and Licensing Board (ASLB) was established to determine whether proposed intervenors have standing to intervene and, if so, whether valid issues exist to necessitate a hearing to determine if there was a good cause to extend such construction permit. In December 1992, the ASLB issued an order denying a hearing on these petitions, and the proposed intervenors have taken actions to appeal this decision. In April 1993, the NRC denied such appeals, and two of the proposed intervenors petitioned the U.S. Court of Appeals for the District of Columbia Circuit to grant a summary reversal of the NRC order and stay the operating license. On February 24, 1994, the appeal was voluntarily dismissed.

The Company is also subject to various other federal, state and local regulations. (See Environmental Matters.)

Fuel Cost Recovery Rule

Pursuant to a PUC rule governing the recovery of fuel costs, the recovery of the Company's eligible fuel costs is provided through fixed fuel factors. The rule allows a utility's fuel factor to be revised upward or downward every six months, according to a specified schedule. Each six months, a utility is required to petition to make either surcharges or refunds to ratepayers, together with interest based on a twelve month average of prime commercial rates, for any material cumulative under- or over-recovery of fuel costs. If the cumulative difference between the under- or over-recovery, plus interest, is in excess of 4% of the annual estimated fuel costs most recently approved by the PUC, it will be deemed to be material. Accordingly, in August 1993, the Company petitioned the PUC for a recovery of approximately $144.5 million, including interest, in under-collected fuel costs through June 30, 1993 which were due primarily to increased natural gas costs. The PUC approved the recovery of such costs in the final order in Docket 11735. The recovery will be offset by the refund of the difference between bonded rates and rates approved in the final order. (See Docket 11735 below, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation and Note 11 to Financial Statements.)

The fuel cost recovery rule also contains a procedure for an expedited change in the fixed fuel factor in the event of an emergency. Final reconciliation of fuel costs must be made either in a reconciliation proceeding, which may cover no more than three years and no less than one year, or in a general rate case. In a final reconciliation, a utility has the burden of proving that fuel costs under review were reasonable and necessary to provide reliable electric service, that it has properly accounted for its fuel-related revenues, and that fuel prices charged to the utility by an affiliate were reasonable and necessary and not higher than prices charged for similar items by such affiliate to other affiliates or nonaffiliates. In addition, the rule provides for recovery of purchased power capacity costs with respect to purchases from qualifying facilities, to the extent such costs are not otherwise included in base rates. Recovery is made on a monthly basis through a Power Cost Recovery Factor (PCRF). The energy-related costs of such purchases are included in the fixed fuel factor. Penalties of up to 10% will be imposed in the event an emergency increase has been granted when there was no emergency or when collections under the PCRF exceed PCRF costs by 10% in any month or 5% in the most recent twelve months.

Docket 11735

In January 1993, the Company made applications to the PUC (Docket 11735) and to its municipal regulatory authorities for upward adjustments in rates for electric service throughout its service area, which would have increased annual operating revenues by approximately $760 million, or 15.3%, based upon the test year ended June 30, 1992. Such request reflected, among other things, costs associated with Comanche Peak Unit 2, costs associated with Comanche Peak Unit 1 after the end of the Docket 9300 (see below) test year, additional ad valorem taxes and certain postretirement benefit costs. In August 1993, pursuant to rules of the PUC, the Company placed its requested rate increase into effect, under bond and subject to refund with interest, applicable to energy sales on and after such date. Revenues were recorded net of an estimated reserve for possible refunds.

In October 1993, the PUC issued an order (Order) approving the terms of an agreement (Settlement Agreement) among the Company, the General Counsel's office of the PUC and applicable intervenors which, among other things, settled all remaining issues relating to the design, construction and cost of Comanche Peak through commencement of commercial operation of Unit 2. The Settlement Agreement provided for the disallowance in Docket 11735 of $250 million of costs relating to the completion of Comanche Peak. Pursuant to the Order, the Company refunded $5 million in fuel charges previously incurred in order to resolve the fuel phase of Docket 11735 under which the Company was seeking reconciliation of approximately $4.6 billion of fuel costs incurred during the three year period ended June 30, 1992, under the fuel rule in effect prior to May 1993. Further, in order to resolve the primary issue in another proceeding which resulted from a complaint filed against the Company in October 1992 by the General Counsel's office of the PUC, as a result of the Order, the Company agreed to write off $83 million of allowance for funds used during construction (AFUDC), which consisted of the amount subject to dispute in such proceeding and similar charges subsequently accrued. Also, under the Settlement Agreement and confirmed in the Docket 11735 final order (see below), the Company will recover, ratably over an eight year period, $197 million of operation and maintenance expenditures incurred by the Company in connection with its recent cost reduction program. However, an additional $25 million of such expenditures will not be subject to recovery and was written off by the Company. As a result of the Settlement Agreement, the Company recorded a charge against earnings in September 1993 of approximately $363 million ($265 million after tax).

On January 28, 1994, the PUC issued a final order in Docket 11735 which provided for a total annual revenue increase of approximately $435 million, or 8.7%. The Company strongly disagrees with the final order and has filed a motion for rehearing with the PUC, and will appeal the outcome, if necessary. As a result of this final order, unless the order is changed on rehearing, the Company will refund the difference between the bonded rates and the rates approved in the final order, including interest, all of which is being fully reserved by the Company. The total amount to be refunded will be determined once approved rates have been implemented, which is expected to be during the second quarter of 1994. The amount to be refunded at December 31, 1993 was approximately $141.2 million. Such refund will be mitigated by a fuel cost surcharge approved by the PUC of approximately $144.5 million, including interest, in under-collected fuel costs through June 30, 1993. (See Fuel Cost Recovery Rule).

In November 1993, an intermediate appellate court in Texas, considering an appeal of another

REGULATION AND RATES — (Concluded)

utility's rate case, ruled that utilizing tax benefits generated by costs not allowed in rates to reduce rates charged to customers was required by prior court rulings for all disallowed costs, including capital costs. The Company believes that such rulings are erroneous and not consistent with the Texas Public Utility Regulatory Act. According to a Private Letter Ruling issued to the Company by the Internal Revenue Service (IRS) with respect to investment tax credits, such ratemaking treatment, to the extent related to property classified for tax purposes as public utility property, would result in a violation of the normalization rules contained in the Internal Revenue Code of 1986, as amended (Code). Violation of the normalization rules would result in a significant adverse effect on the Company's results of operation and liquidity. The tax benefits associated with the Comanche Peak costs disallowed in Docket 9300 (see below) could be affected as a result of the court's method. In addition, in its final order in Docket 11735, the PUC reduced rates for the tax benefits generated by certain costs which were not allowed in rates. However, the PUC recognized the potential for a normalization violation if investment tax credits and tax depreciation generated by disallowed plant costs are used to reduce rates. Therefore, the PUC ordered the Company to obtain a Private Letter Ruling from the IRS with respect to tax depreciation on disallowed plant. Thus, the Company's rates would not reflect the tax depreciation benefit of disallowed plant unless the IRS rules such benefits can be utilized to reduce rates without violating the normalization rules contained in the Code. Such a finding by the IRS would require the Company to refund the tax depreciation benefits to its customers. The Company does not believe it is likely that such refund will occur if the IRS maintains a position similar to that stated in its previous Private Letter Ruling to the Company.

Docket 9300

In September 1991, the PUC issued a final order in the Company's prior rate case (Docket 9300), which provided for a total revenue increase of approximately $442 million and included $695 million of CWIP in rate base to support the revenue increase. It also included a prudence disallowance of $472 million with respect to certain Comanche Peak costs relating to 87.8% of the Company's ownership interest in both units of Comanche Peak. With respect to the Company's reacquisition of the remaining 12.2% minority owner interests in Comanche Peak, the order included an additional disallowance of $909 million.

In November 1991, the Company filed a petition in the 250th Judicial District Court of Travis County, Texas, requesting a reversal and remand of the Docket 9300 final order. Other parties to the PUC proceeding also filed appeals with respect to various portions of the order. In September 1992, after a hearing, the Court entered a judgment in the appeals which affirmed the prudence disallowance of $472 million but reversed and remanded to the PUC for reconsideration those portions of the PUC's final order providing for additional disallowances aggregating $884 million with respect to the Company's reacquisition of minority owner interests in Comanche Peak. The Court recognized that on remand the PUC may adjust the amount of CWIP included in the Company's rate base to be consistent with the PUC's redeterminations regarding the minority owner reacquisitions and the amount of cash working capital. Therefore, the Company does not expect this judgment to affect the rates approved in the Docket 9300 final order. Other parties to this suit have appealed this judgment. The Company disagrees with certain portions of this judgment and also has appealed. It is unable to predict the outcome of such appeals and any reconsiderations by the PUC.

COMPETITION

The electric utility industry in general has become, and is expected to be, increasingly competitive due to a variety of regulatory and economic developments. The level of competition is affected by, among other things, price, reliability of service, the cost of energy alternatives, new technologies and governmental regulations. The Company's electric business is exposed to certain competitive forces in varying degrees.

The Company, like the electric industry generally, faces increasing competition in the supply of bulk power at wholesale. Electric utilities have historically sought to sell surplus capacity and energy outside their traditional service territories. The Energy Act was designed, among other things, to foster competition in the wholesale market by (a) facilitating, through amendments to the Public Holding Company Act of 1935, the ownership and operation of generating facilities by "exempt wholesale generators" (which may include independent power producers as well as affiliates of electric utilities) and (b) authorizing, through amendments to the Federal Power Act, the FERC under certain conditions to order utilities which own transmission facilities to provide wholesale transmission services to or for other utilities and other entities selling electric energy. While the Company has experienced competitive pressures in the wholesale market, resulting in a minor loss of load, wholesale sales constitute a relatively low percentage of total sales. See Item 6. Selected Financial Data - Consolidated Operating Statistics.

The legislatures and/or the regulatory commissions in several states have considered or are considering "retail wheeling" which, in general terms, means the transmission by an electric utility of energy produced by another entity over its transmission and distribution system to a retail customer in such utility's service territory. A requirement to transmit directly to retail customers would have the result of permitting retail customers to purchase electric capacity and energy from, at the election of such customers, the electric utility in whose service area they are located or from any other electric utilities or independent power producers. This issue has not been actively pursued in the Texas legislature or by the PUC.

The Company generally has the right, through PUC certification, to provide electric service to the public within its service area. However, some energy consumers in its service area have the ability to produce their own electricity or use alternative forms of energy. Additionally, the Company operates in some dually certified areas with other utilities.

The Company is unable to predict the extent of future competitive developments or what impact, if any, such developments may have on its operations.

ENVIRONMENTAL MATTERS

The System Companies are subject to various federal, state and local regulations dealing with air and water quality and related environmental matters (see Item 2. Properties — Construction Program for environmental expenditures).

Air

Under the Texas Clean Air Act, the Texas Natural Resource Conservation Commission (TNRCC), formerly the Texas Air Control Board and the Texas Water Commission, has jurisdiction over the permissible level of air contaminant emissions from generating facilities located within the State of

Texas. In addition, the new source performance standards of the Environmental Protection Agency (EPA) promulgated under the federal Clean Air Act, as amended (Clean Air Act), which have also been adopted by the TNRCC, are applicable to such generating units, the construction of which commenced after September 18, 1978. The Company's generating units have been constructed to operate in compliance with current regulations and emission standards promulgated pursuant to these Acts; however, due to variations in the quality of the lignite fuel, operation of certain of the lignite-fueled generating units at reduced loads is required from time to time in order to maintain compliance with these standards. Planned future generating facilities have received state and federal permits and are designed to comply with applicable statutes and regulations.

The Clean Air Act includes provisions which, among other things, place limits on the sulfur dioxide emissions produced by generating units. The Clean Air Act requires that fossil-fueled plants meet new sulfur dioxide emission standards by 1995 (Phase I) and additional sulfur dioxide emission standards by 2000 (Phase II). The Company's generating units are not affected by the Phase I requirements. The applicable Phase II requirements currently are met by 52 out of 56 of the Company's generating units. Because the sulfur dioxide emissions from the other four units are relatively low and alternatives are available to enable these units to reduce sulfur dioxide emissions or utilize compensatory reduction allowances achieved in other units, compliance with the applicable Phase II sulfur dioxide requirements is not expected to have a significant impact on the Company. In January 1993, the EPA issued its "core" regulations to implement the sulfur dioxide reduction program. The Company is preparing compliance plans in accordance with the regulations.

To meet these sulfur dioxide requirements, the Clean Air Act provides for the annual allocation of sulfur dioxide emission allowances to utilities. Under the Clean Air Act, utilities are permitted to transfer allowances within their own systems and to buy or sell allowances. The EPA grants a maximum number of allowances annually to the Company based on the amount of emissions from units in operation during the period 1985-1987. The Clean Air Act also provides that the Company will be granted additional annual allowances for certain Company units under construction based on part of their anticipated emissions. The Company intends to utilize internal allocation of emission allowances within its system and, if it is cost effective, may purchase emission allowances to enable both existing and future electric generating units to meet the requirements of the Clean Air Act. The Company is unable to predict the extent to which it may generate excess allowances or will be able to acquire allowances from others if needed.

Other provisions of the Clean Air Act may require the Company to take other actions. The Company's lignite-fired generating units meet the nitrogen oxide limits currently required by the Clean Air Act. The requirements of the Clean Air Act for ozone nonattainment areas may require nitrogen oxide emission reductions at the Company's natural gas-fired units in the Dallas-Fort Worth area. The Clean Air Act also requires studies over a four year period by the EPA to assess the potential for toxic emissions from utility boilers. The Company is unable to predict either the results of such studies or the effects of any subsequent regulations. Continuous emission monitoring systems are required by the Clean Air Act to be installed by 1995 on most of the Company's fossil-fueled units. Installation began in 1992 and is expected to be completed as required.

ENVIRONMENTAL MATTERS — (Continued)

Only certain parts of the regulations implementing the Clean Air Act have been published as final rules. Until more of these regulations have been promulgated and specific state requirements developed, the Company will not be able to fully determine the cost or method for compliance for these requirements. The Company believes that it can meet the requirements necessary to be in compliance with these provisions as they are developed. Estimates for the capital requirements related to the Clean Air Act are included in the Company's estimated construction expenditures. Any additional capital costs, as well as any increased operating costs associated with new requirements or compliance measures, are expected to be recoverable through rates, as similar costs have been recovered in the past.

Water

The TNRCC and the EPA have jurisdiction over all water discharges (including storm water) from all System Companies' facilities. The Company's facilities presently in operation have been constructed to operate in compliance with applicable state and federal requirements relating to discharge of pollutants into the water. The Company, Fuel Company, and Mining Company have obtained all required waste water discharge permits from the TNRCC and the EPA for facilities in operation and have applied for or obtained all such permits for facilities under construction. The Company, Fuel Company, and Mining Company believe they can satisfy the requirements necessary to obtain any required permits or renewals.

Diversion, impoundment and withdrawal of water for cooling and other purposes are subject to the jurisdiction of the TNRCC. The Company possesses all necessary permits for these activities from the TNRCC for its present operations and plants under construction.

Other

Federal legislation regulating surface mining was enacted in August 1977 and regulations implementing the law have been issued. Mining Company's lignite mining operations are currently regulated at the state level by the Railroad Commission of Texas, with oversight by the United States Department of the Interior's Office of Surface Mining, Reclamation and Enforcement. Surface mining permits have been issued for current Mining Company operations that provide fuel for Big Brown, Monticello and Martin Lake.

Treatment, storage and disposal of solid and hazardous waste are regulated at the state level under the Texas Solid Waste Disposal Act and at the federal level under the Resource Conservation and Recovery Act of 1976, as amended (RCRA). The EPA has issued regulations under the RCRA and the TNRCC has issued regulations under the Texas act applicable to Company facilities. The Company has registered its solid waste disposal sites and has obtained or applied for such permits as are required by such regulations.

Under the federal Low-Level Radioactive Waste Policy Act of 1980, as amended, the State of Texas is required to provide by 1996, either on its own or jointly with other states in a compact, for the disposal of all low-level radioactive waste generated within the state. The State of Texas is taking steps to site, construct and operate a low-level radiooactive waste disposal site by 1996 and submitted a license application in March 1992 for a low-level waste disposal facility. The State of Texas has

ENVIRONMENTAL MATTERS — (Concluded)

entered into an agreement with other states in its region to take and dispose of all low-level radioactive waste from Texas for the period January 1, 1993 through June 30, 1994. It is expected that such material will be stored on-site until other facilities are available.

Item 2. PROPERTIES.

At December 31, 1993, the Company owned or leased and operated the following units:

Electric Generating Units	Fuel Source	Net Capability (MW)	%
47	Natural Gas (a)	11,936	56.7
9	Lignite/Coal (b)	5,845	27.7
2	Nuclear	2,300	10.9
10	Diesel	20	0.1
15	Combustion Turbines (c) ..	975	4.6
	Total	21,076	100.0

(a) Thirty-eight natural gas units are designed to operate on fuel oil for short periods when gas supplies are interrupted or curtailed. Five natural gas units are designed to operate on fuel oil for extended periods.

(b) Includes the Monticello Unit 3 (750 MW).

(c) Natural gas units leased and operated by the Company. Such units are designed to operate on fuel oil for extended periods.

The principal generating facilities and load centers of the Company are connected by 3,861 circuit miles of 345,000 volt transmission lines and 9,098 circuit miles of 138,000 and 69,000 volt transmission lines.

The Company is connected by six 345,000 volt lines to Houston Lighting & Power Company; by three 345,000 volt, eight 138,000 volt and nine 69,000 volt lines to West Texas Utilities Company; by two 345,000 volt, seven 138,000 volt and one 69,000 volt lines to the Lower Colorado River Authority; by four 345,000 volt and eight 138,000 volt lines to the Texas Municipal Power Agency; and at several points with smaller systems operating wholly within Texas. The Company is a member of the Electric Reliability Council of Texas (ERCOT), an intrastate network of investor-owned entities, cooperatives and public entities. ERCOT is the regional reliability coordinating organization for member electric power systems in Texas.

The generating stations and other important units of property of the Company are located on lands owned primarily in fee simple. The greater portion of the transmission and distribution lines of the Company, and of the gas gathering and transmission lines of Fuel Company, has been constructed over lands of others pursuant to easements or along public highways and streets as permitted by law. The rights of the System Companies in the realty on which their properties are located are considered by them to be adequate for their use in the conduct of their business. Minor defects and irregularities customarily found in titles to properties of like size and character may exist, but any such defects and irregularities do not materially impair the use of the properties affected thereby. The Company and Fuel Company have the right of eminent domain whereby they may, if necessary, perfect or secure titles to privately held land used or to be used in their operations. Electric plant of the Company is generally subject to the liens of its mortgages.

Item 2. PROPERTIES (Continued).

During the period from January 1, 1991 to December 31, 1993, the Company made gross property additions of approximately $6,321,587,000 and retirements of property aggregating approximately $162,921,000. Such gross additions amounted to approximately 24.5% of electric plant at December 31, 1993.

CONSTRUCTION PROGRAM

The Company has taken steps to substantially reduce construction expenditures from amounts previously estimated. Such expenditures, excluding AFUDC (see Note 1 to Financial Statements), are presently estimated at $363 million for each of the years 1994, 1995 and 1996. The Company is subject to federal, state and local regulations dealing with environmental protection (see Item 1. Business — Environmental Matters). Expenditures for construction to meet the requirements of such regulations at existing generating units are estimated to be $55 million for 1994 and were approximately $34 million for 1993, $25.4 million for 1992 and $10.4 million for 1991.

The Company's Resource Plan includes two lignite-fueled 750 MW units at Twin Oak currently scheduled for service for the peak seasons of 2000 and 2001, respectively. However, estimated construction expenditures, excluding AFUDC, for the 1994-1996 period do not include any significant amounts for the resumption of construction of these units. Active construction and the accrual of AFUDC on Twin Oak, suspended in 1987 due to forecast changes in load growth, would need to resume in 1996 in order to meet the current schedule. Assuming the units are financed by the Company using traditional methods, approximately $210 million would be added to construction expenditures in 1996.

The Company's Resource Plan also includes 1,502 MW of gas/oil-fueled combustion turbine units (including 272 MW of simple cycle combustion turbines planned for completion during the peak season of 1999), none of which requires significant construction expenditures in the 1994-1996 period reflected above.

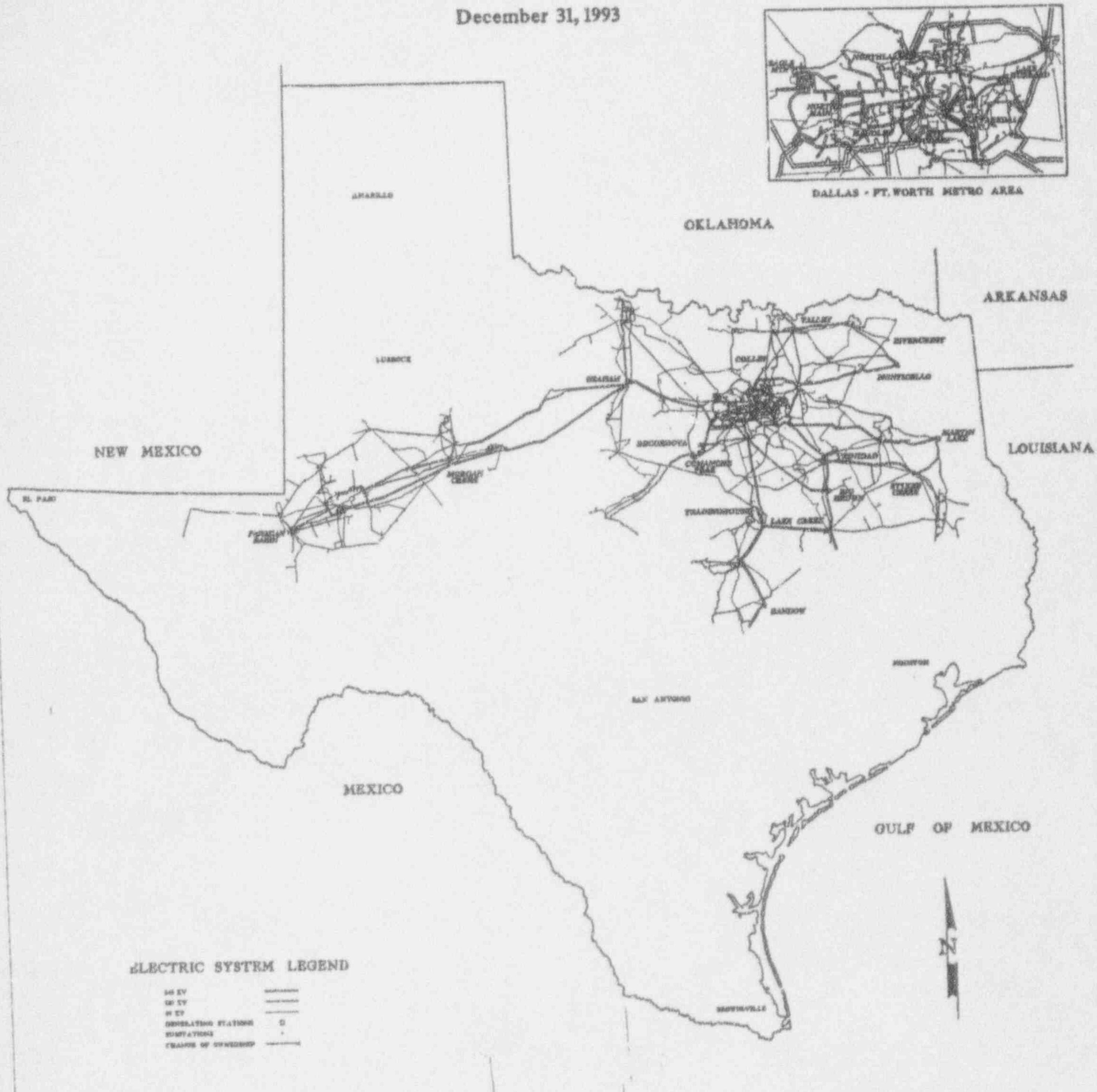
The reevaluation of growth expectations, the effects of inflation, additional regulatory requirements, and the availability of fuel, labor, materials and capital may result in changes in estimated construction costs and dates of completion. Commitments in connection with the construction program, are generally revocable subject to reimbursement to manufacturers for expenditures incurred or other cancellation penalties. (See Item 1. Business — Peak Load and Capability.)

For information regarding financing of the construction program, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation.

Item 2. PROPERTIES (Concluded)

THE COMPANY SYSTEM

December 31, 1993



Item 3. LEGAL PROCEEDINGS.

In November 1991, Sheree Anne Meyer, as custodian for Adam Joseph Davenport, allegedly as a shareholder of Texas Utilities, filed suit in the United States District Court for the Northern District of Texas derivatively on behalf of Texas Utilities and the Company against Texas Utilities and the Company as nominal defendants and J. S. Farrington, Erle Nye, James K. Dobey, Jack W. Evans, William M. Griffin, Margaret N. Maxey, James A. Middleton, Charles R. Perry and William H. Seay, directors of Texas Utilities, and James H. Zumberge, a former director of Texas Utilities, S. S. Swiger, a former officer of Texas Utilities, and T. L. Baker, an officer of the Company. The plaintiff alleges breaches of fiduciary duty and negligence primarily relating to Comanche Peak, which the plaintiff claims have resulted in damages in an amount not less than $1.381 billion. In December 1991, the Court entered an order which stayed this suit until thirty days after entry of a final judgment by the District Court in the Company's appeal of the final order of the PUC in Docket 9300. In September 1992, a final judgment in this appeal was entered by the District Court. (See Item 1. Business — Regulation and Rates.) The plaintiff refused to extend the stay pending the appeals of this judgment and Texas Utilities moved to extend the stay through resolution of the appeals or alternatively to dismiss the suit. In December 1992, this suit was consolidated with a similar suit brought against Texas Utilities by another alleged shareholder. In January 1993, the Court entered an order which stayed the consolidated suit until thirty days after the disposition of all appeals from the final order of the PUC in Docket 9300. (See Item 1. Business — Regulation and Rates.)

Item 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

None.

PART II

Item 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS.

All of the Company's common stock is owned by Texas Utilities.

Reference is made to Note 5 to Financial Statements regarding limitations upon payment of dividends on common stock of the Company.

Item 6. SELECTED FINANCIAL DATA.

FINANCIAL STATISTICS

	Year Ended December 31,				
	1993*	1992	1991*	1990	1989
	(Dollars in Thousands)				
Total assets — end of year	$19,870,990	$17,962,812	$17,093,474	$17,387,276	$16,173,648
Electric plant — gross — end of year	$22,680,508	$21,957,681	$20,865,047	$19,693,580	$18,116,758
Accumulated depreciation and amortization — end of year	4,233,720	3,790,626	3,417,856	3,038,302	2,762,101
Reserve for regulatory disallowances — end of year	1,308,460	1,308,460	1,308,460	—	—
Construction expenditures (including allowance for funds used during construction)	841,181	1,107,555	1,195,680	1,431,647	1,793,890
Capitalization — end of year					
Long-term debt	$ 7,607,090	$ 7,280,301	$ 7,253,626	$ 6,750,635	$ 6,079,503
Preferred stock:					
Not subject to mandatory redemption	1,083,008	909,564	1,007,728	1,007,728	1,007,732
Subject to mandatory redemption	396,917	418,748	425,758	426,737	329,009
Common stock equity	6,029,217	6,198,208	5,741,437	6,452,690	5,814,013
Total	$15,116,232	$14,806,821	$14,428,549	$14,637,790	$13,230,257
Embedded interest cost on long-term debt — end of year	8.8%	9.2%	9.7%	9.8%	9.8%
Embedded dividend cost on preferred stock — end of year	7.6%	8.4%	8.5%	8.6%	8.3%
Income (loss) before cumulative effect of a change in accounting principle	$476,526	$740,216	$(289,173)	$964,276	$886,176
Cumulative effect of a change in accounting for unbilled revenue (Net of taxes of $41,679,000)(Note 13)	—	80,907	—	—	—
Net income (loss)	$476,526	$821,123	$(289,173)	$964,276	$886,176
Dividends declared on common stock	$707,382	$645,260	$ 650,940	$607,230	$542,298
Ratio of earnings to fixed charges	2.0	2.5	0.3	2.5	2.6
Allowance for funds used during construction as percent of earnings to common stock	72.9%	43.3%	— %	73.1%	65.1%
Return on average common stock equity	5.9%	11.8%	(6.7)%	13.8%	14.0%

* Certain financial statistics for the years 1993 and 1991 were affected by the Company recording regulatory disallowances in the rate orders issued by the Public Utility Commission of Texas in Dockets 11735 and 9300, respectively. (See Note 11 to Financial Statements.)

Item 6. SELECTED FINANCIAL DATA (Concluded).

OPERATING STATISTICS

	Year Ended December 31,				
	1993	1992	1991	1990	1989
ELECTRIC ENERGY GENERATED AND PURCHASED (MWh)					
Generated — net station output	79,105,495	74,652,339	76,326,601	76,044,403	74,925,395
Purchased and net interchange	12,431,763	11,417,251	11,027,061	12,179,724	12,588,899
Total generated and purchased	91,537,258	86,069,590	87,353,662	88,224,127	87,514,294
Company use, losses and unaccounted for	6,347,232	5,747,156	4,996,123	4,496,294	5,571,768
Total electric energy sales	85,190,026	80,322,434	82,357,539	83,727,833	81,942,526
ELECTRIC ENERGY SALES (MWh)					
Residential	29,992,945	27,266,411	28,505,885	28,157,802	27,294,613
Commercial	23,911,679	22,959,464	23,012,114	23,429,101	22,539,351
Industrial	21,333,748	21,108,894	21,482,750	21,839,196	21,377,542
Government and municipal	5,315,258	5,032,780	5,056,868	4,914,503	4,683,259
Total general business	80,553,630	76,367,549	78,057,617	78,340,602	75,894,765
Other electric utilities	4,636,396	3,954,885	4,299,922	5,387,231	6,047,761
Total electric energy sales	85,190,026	80,322,434	82,357,539	83,727,833	81,942,526
OPERATING REVENUES (thousands)					
Residential	$2,236,469	$1,995,767	$2,043,421	$1,859,239	$1,752,679
Commercial	1,489,691	1,405,546	1,391,995	1,266,030	1,228,672
Industrial	859,638	849,365	852,952	801,821	817,802
Government and municipal	338,758	304,286	303,597	273,596	251,941
Total general business	4,924,556	4,554,964	4,591,965	4,200,686	4,051,094
Other electric utilities	227,938	209,170	228,075	232,755	245,821
Total from electric energy sales	5,152,494	4,764,134	4,820,040	4,433,441	4,296,915
Other operating revenues (including unbilled revenue and over/under-recovered fuel revenue)*	256,662	142,561	71,482	107,474	21,650
Total operating revenues	$5,409,156	$4,906,695	$4,891,522	$4,540,915	$4,318,565
ELECTRIC CUSTOMERS (end of year)					
Residential	1,986,946	1,952,916	1,921,119	1,900,005	1,875,524
Commercial	215,621	210,185	205,555	205,359	210,824
Industrial	21,716	21,969	22,156	22,214	22,024
Government and municipal	28,555	28,204	27,719	24,538	23,434
Total general business	2,252,838	2,213,274	2,176,549	2,152,116	2,131,806
Other electric utilities	228	243	247	63	64
Total electric customers	2,253,066	2,213,517	2,176,796	2,152,179	2,131,870
RESIDENTIAL STATISTICS (excludes master-metered customers, kWh sales and revenues)					
Average kWh per customer	14,459	13,329	14,099	14,050	13,754
Average revenue per kWh	7.78¢	7.41¢	7.26¢	6.69¢	6.50¢

Industrial classification includes service to Alcoa-Sandow:					
Electric energy sales (MWh)	3,166,797	3,157,852	3,359,824	3,517,431	3,276,303
Operating revenues (thousands)	$53,352	$56,043	$55,987	$55,274	$56,985

* In 1992, other operating revenues do not include $122,586,000 of unbilled base rate revenues which were reclassified as a cumulative effect of a change in accounting principle effective January 1, 1992.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION.

Liquidity and Capital Resources

The primary capital requirements of Texas Utilities Electric Company (Company) in 1993 and as estimated for 1994 through 1996 are as follows:

	1993	1994	1995	1996
		Thousands of Dollars		
Cash construction expenditures (excluding allowance for funds used during construction)	$ 598,000	$363,000	$363,000	$363,000
Nuclear fuel (excluding allowance for funds used during construction) and non-utility property	83,000	49,000	44,000	54,000
Maturities and redemptions of long-term debt, sinking fund requirements and redemptions of preferred stock	2,703,000	145,000	110,000	102,000
Total	$3,384,000	$557,000	$517,000	$519,000

For information concerning construction work contemplated by the Company and the commitments with respect thereto, see Item 2. Properties — Construction Program and Note 12 to Financial Statements.

The Company has generated cash from operations sufficient to meet operating needs, pay dividends on capital stock and finance a portion of capital requirements. Factors affecting the ability of the Company to continue to fund a portion of its capital requirements from operations include adequate rate relief in the future reflecting regulatory practices allowing recovery of capital investment through adequate depreciation rates, normalization of federal income taxes, recovery of the cost of fuel and purchased power and the opportunity to earn competitive rates of return required in the capital markets.

In order to remain competitive and in response to the recent disappointing rate order in Docket 11735, the Company has taken steps to reduce operating costs and capital expenditures and is reviewing various alternatives and strategies to improve future earnings potential and its basic financial position. This review may result in further initiatives which may include, but not necessarily be limited to, alternative uses or disposition of existing assets, somewhat greater utilization of short-term and variable rate securities, new marketing and rate initiatives and application for additional rate increases from regulatory authorities. It is not possible at this time to predict the effect any of these possible initiatives will have on the Company's financial position or its results of operation. For 1993, approximately 62% of the cash needed for construction expenditures was generated from operations by the Company. The Company believes internal cash generation will increase as a result of the Docket 11735 rate order and through the implementation of the initiatives discussed above.

In August 1993, the Company placed Comanche Peak Unit 2 in commercial operation and implemented, under bond, its 15.3% rate increase requested in Docket 11735. In September 1993, the Company recorded a charge against earnings of approximately $363 million ($265 million after tax) related to an agreement (Settlement Agreement) among the parties involved in the Company's Docket 11735. The Settlement Agreement resolved all issues in the prudence and fuel phases of Docket 11735 and also permits the Company to recover, ratably over an eight year period, $197 million of expenditures incurred in connection with the Company's recent cost reduction program. The Settlement Agreement also resolved the difference between the Company and the Public Utility Commission of Texas (PUC) staff that was the primary issue in another proceeding related to the accrual of an allowance for funds used during construction (AFUDC), during the bonded rate period of Docket 9300, on construction work in progress (CWIP) that was subsequently included in rate base pursuant to the final order in Docket 9300.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION (Continued).

Liquidity and Capital Resources — (continued)

On January 28, 1994, the PUC issued a final order in Docket 11735 which provided for a total annual revenue increase of approximately $435 million, or 8.7%. The Company strongly disagrees with the final order and has filed a motion for rehearing with the PUC, and will appeal the outcome, if necessary. As a result of this final order, unless the order is changed on rehearing, the Company will refund the difference between the bonded rates and the rates approved in the final order, including interest, all of which is being fully reserved by the Company. The total amount to be refunded will be determined once approved rates have been implemented, which is expected to be during the second quarter of 1994. The amount to be refunded at December 31, 1993 was approximately $141.2 million. Such refund will be mitigated by a fuel cost surcharge approved by the PUC of approximately $144.5 million, including interest, in under-collected fuel costs through June 30, 1993. For additional information regarding the rate decision, see Item 1. Business — Regulation and Rates and Note 11 to Financial Statements.

As a result of the final order and its effects on earnings, the Company could be restricted from issuing additional shares of preferred stock. The Company does not believe this restriction would materially affect its ability to fund its continuing operations or capital requirements. Although the Company cannot predict the outcome of its appeal of the Docket 9300 rate decision or its expected appeal of the Docket 11735 rate decision, future regulatory actions or any changes in economic and securities market conditions, no changes are expected in trends or commitments, other than those discussed above, which might significantly alter its basic financial position.

On November 14, 1993, the emissions chimney for Unit 3 of the Monticello Steam Electric Station collapsed. The cause of the collapse has not been determined but such unit and the associated lignite mining operation will be inoperative until completion of repairs. The Company is formulating the engineering, procurement and construction plans that will return the unit to service in 1995. The cost of repairs is covered by the Company's insurance which includes a $2,000,000 deductible. Therefore, the Company does not expect the accident to materially effect its results of operation or financial position.

External funds of a permanent or long-term nature are obtained through the sales of common stock to Texas Utilities Company (Texas Utilities), preferred stock and long-term debt. The capitalization ratios of the Company at December 31, 1993 consisted of approximately 50% long-term debt, 10% preferred stock and 40% common stock equity.

The Company had financings totaling $3,378,707,370 in 1993. Proceeds from such financings were used primarily for the early redemption of higher coupon debt and higher dividend preferred stock. The Company redeemed or made principal payments of $2,702,847,000 on long-term debt and preferred stock. Financings in 1993 by the Company included the following:

Long-Term Debt:

Description	Principal Amount	Interest Rate	Maturity
First mortgage and collateral trust bonds	$2,050,000,000	5-1/2% to 7-7/8%	1998 to 2025
Taxable pollution control series*	100,000,000	4.25%	2023
Pollution control series	298,465,000	5-1/2% to 6.10%	2022 to 2028
Total	$2,448,465,000		

* The taxable pollution control series bonds are in a flexible mode and while in such mode will be remarketed for periods of less than 270 days and are secured by an irrevocable letter of credit. The Company has sufficient unused existing lines of credit that would allow refinancing of the bonds on a long-term basis should remarketing prove unsuccessful.

Liquidity and Capital Resources — (continued)

	Shares	Net Proceeds
Common Stock	3,400,000	$198,900,000

	Shares	Net Proceeds	Dividends
Preferred Stock	7,500,000*	$731,342,370	$6.375 to $8.20

* Four depositary shares have been issued with respect to each of 5,000,000 of such underlying shares of preferred stock.

The replacement of higher coupon debt and higher dividend preferred stock during 1993 reduced interest and dividend requirements by approximately $39,000,000 on an annualized basis. The Company redeemed $15,000,000 of 10.45% First Mortgage and Collateral Trust Bonds, Secured Medium-Term Notes on March 16, 1994 and intends to redeem $335,000,000 of First Mortgage Bonds with interest rates ranging from 7-3/8% to 9-1/2% on April 1, 1994 with each redemption subject to the deposit of the necessary redemption monies by the Company. Additional early redemptions of long-term debt and preferred stock may occur from time to time in amounts presently undetermined. (See Notes 6 and 7 to Financial Statements.)

The Company expects to sell additional debt and equity securities as needed (subject to the possible restriction on the issuance of additional shares of preferred stock as discussed above) including the possible future sale of up to $450,000,000 of First Mortgage and Collateral Trust Bonds currently registered with the Securities and Exchange Commission for offering pursuant to Rule 415 under the Securities Act of 1933. The Company also has 250,000 shares of Cumulative Preferred Stock ($100 liquidation value) similarly registered. It is the intent of the Company and Texas Utilities to negotiate a new credit facility prior to the scheduled reduction in June 1994 in the joint lines of credit of the Company and Texas Utilities. The new facility would be used for working capital, as back-up for commercial paper and for other corporate purposes. For information regarding short-term financings of the Company, see Note 3 to Financial Statements.

The Company's capital requirements have not been significantly affected by the requirements of the federal Clean Air Act, as amended (Clean Air Act). Although the Company is unable to fully determine the cost of compliance with the Clean Air Act, it is not expected to have a significant impact on the Company. Any additional capital costs, as well as any increased operating costs associated with these new requirements, are expected to be recoverable through rates, as similar costs have been recovered in the past.

The National Energy Policy Act of 1992 addresses a wide range of energy issues and is intended to increase competition in electric generation and broaden access to electric transmission systems. The Company is unable to predict the impact of regulations implementing this legislation on its operations until such regulations are promulgated and approved. However, the Company believes that such legislation reflects the trend toward increased competition in the energy industry.

While the Company has experienced competitive pressures in the wholesale market resulting in a minor loss of load, wholesale sales constitute a relatively low percentage of total sales. The Company is unable to predict the extent of future competitive developments or what impact, if any, such developments may have on operations. (See Item 1. Business — Competition.)

See Item 6. Selected Financial Data — Financial Statistics for additional information.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION (Continued).

Results of Operation

Operating revenues increased 10.2% and 0.3% for the years ended December 31, 1993 and 1992, respectively. The following table details the factors contributing to these changes:

Factors	Increase (Decrease) 1993	1992
	Thousands of Dollars	
Base rate revenue	$333,187	$(57,824)
Fuel revenue	150,707	42,161
Power cost recovery factor revenue	(1,313)	(89)
Unbilled revenue and other	19,880	30,925
Total	$502,461	$ 15,173

Base rate revenue increased in 1993 due to higher energy sales and higher rate levels implemented in August 1993 as compared to a decrease in base rate revenues in 1992 as a result of lower energy sales. Energy sales increased 6.1% for 1993 and decreased 2.5% for 1992. The increase in energy sales in 1993 was due primarily to increased customer usage resulting from more normal weather conditions and an increase in customers, while the decrease in 1992 resulted from milder than normal weather and unfavorable economic conditions, partially offset by an increase in customers. The rate increase placed in effect in August 1993 increased base rate revenues, net of amounts to be refunded, by approximately $177 million in 1993. The increase in fuel revenue for 1993 resulted from increased energy sales and increased fuel costs. The increase in fuel revenue in 1992 was primarily due to fuel refunds in 1991, partially offset by decreased energy sales in 1992. The increase in unbilled revenue and other resulted from a larger accrual of unbilled revenue in both periods. (See Note 13 to Financial Statements.)

Fuel and purchased power expense increased 9.6% and 1.1% for 1993 and 1992, respectively. Fuel and purchased power expense increased for 1993 primarily due to increased energy sales and the increase in the price of gas partially offset by an increased utilization of nuclear fuel. The 1992 increase in fuel and purchased power was primarily the result of an increased price of gas which more than offset the decrease in generation. (See Item 1. Business — Fuel Supply and Purchased Power and Item 6. Selected Financial Data — Operating Statistics.)

Total operating expenses, excluding fuel and purchased power, increased 15.1% for 1993 and decreased 1.9% for 1992. Operation, maintenance and depreciation expenses increased in 1993 as a result of the commencement of commercial operation of Unit 2 of Comanche Peak in August 1993. Operation expense in 1993 also increased due to higher pension costs and other postretirement benefits costs associated with Financial Accounting Standards Board (FASB) Statement 106 "Employers' Accounting for Postretirement Benefits Other Than Pensions", partially offset by lower employee labor costs. Maintenance expense was also affected by inventory adjustments during the third and fourth quarters of 1993. Operation and maintenance expenses decreased in 1992 primarily due to decreased employee related costs and management's efforts to further reduce other costs through a cost reduction program. Depreciation expense decreased in 1992 as a result of recording the disallowances associated with Comanche Peak Unit 1 in the Company's Docket 9300 rate order. Taxes other than income increased in 1993 due primarily to increased local gross receipts taxes resulting from higher tax rates on increased revenues and an increase in ad valorem taxes. The increase in 1993 was partially offset by a refund of prior years franchise taxes of approximately $23,875,000.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION (Continued).

Results of Operation — (continued)

AFUDC decreased 13.5% and 16.4% in 1993 and 1992, respectively. The decrease in 1993 was primarily due to the discontinuation of the accrual of AFUDC on Unit 2 of Comanche Peak when such unit achieved commercial operation in August 1993. This decrease was partially offset by the change to a gross rate in 1993 related to the adoption of FASB Statement 109, "Accounting for Income Taxes", for projects commenced before March 1986 (see Notes 1 and 8 to Financial Statements). The decrease in 1992 was caused by the implementation of the Docket 9300 rate order placing $695 million of CWIP in rate base and the exclusion of $485 million of CWIP disallowed on Unit 2 of Comanche Peak. (See Note 11 to Financial Statements.)

The regulatory disallowances reflect charges resulting from the Settlement Agreement among the parties in Docket 11735. (See Note 11 to Financial Statements.)

Other income and deductions — net increased for 1993 and decreased for 1992, primarily due to changes in interest income for each year related to changes in the levels of temporary cash investments between years and an increase in interest income on under-recovered fuel revenue in 1993.

Federal income taxes — other income decreased in 1993 due to the effect of recording the taxes associated with the regulatory disallowances and increased in 1992 because 1991 was affected by the recording of taxes associated with the provision for regulatory disallowances. (See Notes 8 and 11 to Financial Statements.)

Total interest charges, excluding AFUDC, decreased 0.4% and 6.0% for 1993 and 1992, respectively. Interest on mortgage bonds increased in 1993 as a result of new issues sold and the annualization of interest on bond issues sold in the prior period, partially offset by reduced interest requirements as a result of the Company's refinancing efforts. The decrease in 1992 resulted from retirements and redemptions of certain higher rate issues. Interest on other long-term debt decreased in both periods due to the continuing retirement of debt incurred on the purchases of the minority ownership interests in Comanche Peak and refunding of higher interest rate debt. Other interest expense decreased in all periods due primarily to decreased interest on short-term borrowings and decreased interest on over-recovered fuel revenues partially offset by increased amortization of debt issuance expenses and redemption premiums.

The cumulative effect of recording unbilled revenue reflects the accounting change made on January 1, 1992, by the Company to begin recording base rate revenue for energy sales sold but not billed.

The major factors affecting earnings in 1993 were the implementation of the rate increase, the recording of the regulatory disallowances, the discontinuation of AFUDC on Unit 2 of Comanche Peak and the commencement of depreciation on approximately $668 million of investment in Comanche Peak Unit 2 incurred after the end of the Docket 11735 test year which was not included in rates. The factors mentioned above resulted in a decrease in net income of 42.0% for 1993. The change in accounting for unbilled revenue in 1992 and the recording of the provision for regulatory disallowances in 1991 (see Note 11 to Financial Statements) resulted in an increase to net income in 1992 over 1991. The net loss in 1991 was due to the recognition of the provision for regulatory disallowances and the provision for refunds and related interest. Another major factor affecting earnings in 1992 and 1991 was the discontinuation of the accrual of AFUDC on approximately $1.3 billion of investment in Comanche Peak Unit 1, incurred after the end of the test year, which was not reflected in rates until Docket 11735 bonded rates were implemented.

Item 7. **MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION (Concluded).**

Results of Operation — (concluded)

Preferred stock dividends decreased 2.7% and 2.6% for 1993 and 1992, respectively, primarily due to the redemption of series with higher dividend rates partially offset by dividends on new issues.

Accounting Changes

In November 1993, Statement of Financial Accounting Standards No. 112, "Employers' Accounting for Postemployment Benefits" (Statement 112) was issued. Statement 112 is effective for fiscal years beginning after December 15, 1993. Statement 112 applies to certain types of postemployment benefits provided to former or inactive employees after employment but before retirement. The Company does not expect Statement 112 to have a material effect on the Company's financial position or results of operation.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

TEXAS UTILITIES ELECTRIC COMPANY

STATEMENTS OF INCOME

	Year Ended December 31,		
	1993	1992	1991
		Thousands of Dollars	
OPERATING REVENUES	$5,409,156	$4,906,695	$4,891,522
OPERATING EXPENSES			
Fuel and purchased power	1,946,049	1,775,885	1,756,423
Operation	756,596	684,095	729,615
Maintenance	341,840	297,079	304,683
Depreciation and amortization	427,992	409,006	425,216
Federal income taxes	343,485	197,694	152,963
Taxes other than income	445,220	423,505	437,347
Total operating expenses	4,261,182	3,787,264	3,806,247
OPERATING INCOME	1,147,974	1,119,431	1,085,275
OTHER INCOME (LOSS)			
Allowance for equity funds used during construction	150,115	194,462	251,744
Regulatory disallowances (Note 11)	(359,556)	—	(1,381,145)
Other income and deductions — net	9,114	7,882	12,462
Federal income taxes (Notes 8 and 11)	101,745	(2,479)	362,852
Total other income (loss)	(98,582)	199,865	(754,087)
TOTAL INCOME	1,049,392	1,319,296	331,188
INTEREST CHARGES			
Interest on mortgage bonds	610,999	598,235	608,729
Interest on other long-term debt	45,787	54,379	61,822
Other interest	29,186	36,202	62,111
Allowance for borrowed funds used during construction	(113,106)	(109,736)	(112,301)
Total interest charges	572,866	579,080	620,361
Income (loss) before cumulative effect of a change in accounting principle	476,526	740,216	(289,173)
Cumulative effect of a change in accounting for unbilled revenue (Net of taxes of $41,679,000)(Note 13)	—	80,907	—
NET INCOME (LOSS)	476,526	821,123	(289,173)
PREFERRED STOCK DIVIDENDS	115,232	118,418	121,603
NET INCOME (LOSS) AFTER PREFERRED STOCK DIVIDENDS	$ 361,294	$ 702,705	$ (410,776)

See accompanying Notes to Financial Statements.

TEXAS UTILITIES ELECTRIC COMPANY

STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	1993	1992	1991
	Thousands of Dollars		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 476,526	$ 821,123	$ (289,173)
Adjustments to reconcile net income (loss) to cash provided by operating activities:			
Depreciation and amortization	512,195	444,243	450,525
Deferred federal income taxes — net	118,368	177,097	(247,264)
Federal investment tax credits — net	(19,698)	(20,322)	(53,498)
Allowance for equity funds used during construction	(150,115)	(194,462)	(251,744)
Regulatory disallowances (Note 11)	359,556	—	1,381,145
Provision for refunds and related interest — net	(27,235)	(18,475)	44,893
Cumulative effect of a change in accounting for unbilled revenue – net (Note 13)	—	(80,907)	—
Changes in assets and liabilities:			
Receivables — net	(88,104)	101,299	(29,854)
Inventories	10,557	(17,791)	(19,224)
Accounts payable — net	(5,763)	36,613	(17,095)
Interest and taxes accrued	16,471	1,514	84,021
Other working capital	151,153	54,372	42,999
Under-recovered fuel revenue — net of deferred taxes	(83,501)	(27,854)	(28,729)
Voluntary retirement/severance program	—	(90,905)	—
Other — net	10,025	(2,089)	21,105
Cash provided by operating activities	1,280,435	1,183,456	1,088,107
CASH FLOWS FROM FINANCING ACTIVITIES:			
Sales of securities:			
First mortgage bonds	2,448,465	1,808,595	737,298
Commercial paper	—	—	215,000
Preferred stock	731,342	—	—
Common stock	198,900	401,163	350,463
Retirement of long-term debt and preferred stock	(2,702,847)	(1,805,545)	(237,178)
Change in notes payable to parent	36,684	51,750	(134,000)
Change in notes payable to banks	(250,000)	—	—
Preferred stock dividends paid	(114,933)	(120,362)	(121,610)
Common stock dividends paid	(707,382)	(645,260)	(650,940)
Debt premium, discount, financing and reacquisition expenses	(132,366)	(126,846)	(22,298)
Cash provided by (used in) financing activities	(492,137)	(436,505)	136,735
CASH FLOWS FROM INVESTING ACTIVITIES:			
Construction expenditures	(841,181)	(1,107,555)	(1,195,680)
Allowance for equity funds used during construction (excluding amount for nuclear fuel)	138,941	179,519	232,068
Change in construction receivables/payables — net	(33,976)	(4,301)	(6,074)
Cash construction expenditures	(736,216)	(932,337)	(969,686)
Non-utility property — net	(6)	1,518	(27)
Nuclear fuel (excluding allowance for equity funds used during construction)	(16,889)	(33,656)	(16,694)
Other investments	(12,944)	(8,591)	(11,278)
Cash used in investing activities	(766,055)	(973,066)	(997,685)
NET CHANGE IN CASH AND CASH EQUIVALENTS	22,243	(226,115)	227,157
CASH AND CASH EQUIVALENTS — BEGINNING BALANCE	5,686	231,801	4,644
CASH AND CASH EQUIVALENTS — ENDING BALANCE	$ 27,929	$ 5,686	$ 231,801

See accompanying Notes to Financial Statements.

TEXAS UTILITIES ELECTRIC COMPANY

BALANCE SHEETS

ASSETS

	December 31,	
	1993	1992
	Thousands of Dollars	
ELECTRIC PLANT		
In service:		
Production	$15,501,384	$10,490,214
Transmissi n	1,537,447	1,493,602
Distribution	3,773,359	3,567,646
General	449,095	440,665
Total	21,261,285	15,992,127
Less accumulated depreciation	4,118,855	3,741,020
Electric plant in service less accumulated depreciation	17,142,430	12,251,107
Construction work in progress	944,465	5,528,222
Nuclear fuel (net of accumulated amortization: 1993 — $114,865,000; 1992 — $49,606,000)	320,891	358,087
Held for future use	39,002	29,639
Electric plant less accumulated depreciation and amortization	18,446,788	18,167,055
Less reserve for regulatory disallowances (Note 11)	1,308,460	1,308,460
Net electric plant	17,138,328	16,858,595
INVESTMENTS	48,943	35,993
CURRENT ASSETS		
Cash in banks	6,910	5,686
Temporary cash investments	21,019	—
Special deposits	21,388	[illegible]
Accounts receivable:		
Customers	217,924	113,576
Other	17,557	30,289
Allowance for uncollectible accounts	(6,304)	(1,613)
Inventories — at average cost:		
Materials and supplies	177,735	187,301
Fuel stock	90,544	91,535
Prepaid taxes	17,776	9,778
Deferred federal income taxes	43,625	—
Other current assets	16,201	17,693
Total current assets	624,375	461,755
DEFERRED DEBITS		
Unamortized regulatory assets:		
Debt reacquisition costs	282,119	214,245
Cancelled lignite unit costs	20,678	23,189
Rate case costs	66,508	52,006
Litigation and settlement costs	72,685	72,685
Voluntary retirement/severance program	180,180	204,881
Recoverable deferred federal income taxes — net (Note 8)	1,239,360	—
Other regulatory assets	18,480	—
Under-recovered fuel revenue	204,772	75,152
Other deferred debits	47,247	36,996
Total deferred debits	2,132,029	679,154
Less reserve for regulatory disallowances (Note 11)	72,685	72,685
Net deferred debits	2,059,344	606,469
Total	$19,870,990	$17,962,812

See accompanying Notes to Financial Statements.

TEXAS UTILITIES ELECTRIC COMPANY

BALANCE SHEETS

CAPITALIZATION AND LIABILITIES

	December 31, 1993	December 31, 1992
	Thousands of Dollars	
CAPITALIZATION		
Common stock without par value:		
Authorized shares — 180,000,000		
Outstanding shares: 1993 — 152,000,000; 1992 — 148,600,000	$ 4,916,525	$ 4,717,625
Retained earnings	1,112,692	1,480,583
Total common stock equity	6,029,217	6,198,208
Preferred stock:		
Not subject to mandatory redemption	1,083,008	909,564
Subject to mandatory redemption	396,917	418,748
Long-term debt, less amounts due currently	7,607,090	7,280,301
Total capitalization	15,116,232	14,806,821
CURRENT LIABILITIES		
Notes payable:		
Parent	88,434	51,750
Banks	—	250,000
Long-term debt due currently	145,188	164,054
Accounts payable:		
Affiliates	112,715	138,586
Other	136,540	151,587
Dividends declared	27,681	27,795
Customers' deposits	50,129	52,640
Taxes accrued	284,507	257,384
Interest accrued	170,764	181,415
Refunds due to customers	141,153	—
Other current liabilities	93,448	87,789
Total current liabilities	1,250,559	1,363,000
DEFERRED CREDITS AND OTHER NONCURRENT LIABILITIES		
Accumulated deferred federal income taxes (Note 8)	2,577,989	889,576
Unamortized federal investment tax credits	687,907	707,358
Other deferred credits and noncurrent liabilities	238,303	196,057
Total deferred credits and other noncurrent liabilities	3,504,199	1,792,991
COMMITMENTS AND CONTINGENCIES (Notes 2 and 12)	—	—
Total	$19,870,990	$17,962,812

See accompanying Notes to Financial Statements.

TEXAS UTILITIES ELECTRIC COMPANY
STATEMENTS OF RETAINED EARNINGS

	Year Ended December 31,		
	1993	1992	1991
	Thousands of Dollars		
BALANCE AT BEGINNING OF YEAR	$1,480,583	$1,424,974	$2,486,690
ADD — NET INCOME (LOSS)	476,526	821,123	(289,173)
Total	1,957,109	2,246,097	2,197,517
DEDUCT			
Cash Dividends:			
Preferred stock:			
$ 4.50 series ($ 4.50 per share per annum)	334	334	334
4.00 series ($ 4.00 per share per annum)	280	280	280
4.56 series ($ 4.56 per share per annum)	609	609	609
4.00 series ($ 4.00 per share per annum)	440	440	440
4.56 series ($ 4.56 per share per annum)	296	296	296
4.24 series ($ 4.24 per share per annum)	424	424	424
4.64 series ($ 4.64 per share per annum)	464	464	464
4.84 series ($ 4.84 per share per annum)	339	339	339
4.00 series ($ 4.00 per share per annum)	280	280	280
4.76 series ($ 4.76 per share per annum)	476	476	476
5.08 series ($ 5.08 per share per annum)	407	407	407
4.80 series ($ 4.80 per share per annum)	480	480	480
4.44 series ($ 4.44 per share per annum)	666	666	666
7.20 series ($ 7.20 per share per annum)	1,440	1,440	1,440
7.80 series ($ 7.80 per share per annum)	2,339	2,339	2,339
8.92 series ($ 8.92 per share per annum)	1,438	1,784	1,784
6.84 series ($ 6.84 per share per annum)	1,368	1,368	1,368
7.24 series ($ 7.24 per share per annum)	1,809	1,809	1,809
7.44 series ($ 7.44 per share per annum)	2,232	2,232	2,232
7.48 series ($ 7.48 per share per annum)	2,244	2,244	2,244
8.20 series ($ 8.20 per share per annum)	2,460	2,460	2,460
8.44 series ($ 8.44 per share per annum)	2,532	2,532	2,532
9.32 series ($ 9.32 per share per annum)	1,428	2,796	2,796
9.36 series ($ 9.36 per share per annum)	1,668	2,808	2,808
8.68 series ($ 8.68 per share per annum)	1,881	2,604	2,604
8.16 series ($ 8.16 per share per annum)	2,444	2,444	2,444
8.32 series ($ 8.32 per share per annum)	2,010	2,496	2,496
8.84 series ($ 8.84 per share per annum)	1,914	2,652	2,652
9.48 series ($ 9.48 per share per annum)	5,835	8,944	9,236
8.92 series ($ 8.92 per share per annum)	3,595	4,460	4,460
10.00 series ($10.00 per share per annum)	2,814	4,900	5,000
10.92 series ($10.92 per share per annum)	819	3,276	3,276
10.12 series ($10.12 per share per annum)	1,082	3,542	3,542
10.08 series ($10.08 per share per annum)	1,664	2,999	3,140
11.32 series ($11.32 per share per annum)	867	3,396	3,396
9.64 series ($ 9.64 per share per annum)	9,640	9,640	9,640
10.375 series ($10.375 per share per annum)	7,781	7,781	7,781
9.875 series ($ 9.875 per share per annum)	2,469	2,469	2,468
8.20 series ($8.20 per share per annum)	9,738	—	—
7.98 series ($7.98 per share per annum)	2,928	—	—
7.50 series ($7.50 per share per annum)	6,140	—	—
7.22 series ($7.22 per share per annum)	2,695	—	—
6.98 series ($6.98 per share per annum)	3,898	—	—
6.375 series ($6.375 per share per annum)	1,753	—	—
Adjustable rate series A	6,500	6,500	6,500
Adjustable rate series B	5,950	5,950	6,014
Stated rate auction series A	—	6,180	8,240
Flexible adjustable rate series A	1,975	4,244	4,500
Flexible adjustable rate series B	1,975	4,244	4,500
Common stock (per share: 1993—$4.68; 1992—$4.48; 1991—$4.80)	707,382	645,260	650,940
Total cash dividends	822,202	763,288	772,136
Dividends other than cash — accretions	413	390	407
Total dividends	822,615	763,678	772,543
Preferred stock redemption costs	21,802	1,836	—
BALANCE AT END OF YEAR	$1,112,692	$1,480,583	$1,424,974

See accompanying Notes to Financial Statements.

1. Significant Accounting Policies

System of Accounts — The accounting records of Texas Utilities Electric Company (Company) are maintained in accordance with the Federal Energy Regulatory Commission's Uniform System of Accounts as adopted by the Public Utility Commission of Texas (PUC). Certain financial statement items for 1992 and 1991 have been reclassified to conform to the 1993 presentation.

Electric Plant — Electric plant is stated at original cost. The cost of property additions to electric plant includes labor and materials, applicable overhead and payroll-related costs and an allowance for funds used during construction.

Allowance For Funds Used During Construction — Allowance for funds used during construction (AFUDC) is a cost accounting procedure whereby amounts based upon interest charges on borrowed funds and a return on equity capital used to finance construction are added to electric plant. The accrual of AFUDC is in accordance with generally accepted accounting principles for the industry, but does not represent current cash income.

The Company is capitalizing AFUDC, compounded semi-annually, on expenditures for ongoing construction work in progress (CWIP) and nuclear fuel in process not otherwise allowed in rate base by regulatory authorities. Effective January 1, 1993, the Company began using a gross rate of 10.4% for AFUDC for all construction to comply with Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes" (Statement 109). In 1992 and 1991, the Company used a net-of-tax rate of 8.8% and 10.4%, respectively, on projects commenced before March 1, 1986, and a gross rate of 10.4% and 12.0%, respectively, on projects commenced thereafter. Rates were determined on the basis of, but are less than, the cost of capital used to finance the construction program.

Depreciation of Electric Plant — Depreciation is generally based upon an amortization of the original cost of depreciable properties (net of regulatory disallowances) on a straight-line basis over the estimated service lives of the properties. Depreciation as a percent of average depreciable property approximated 2.4%, 2.7% and 2.9% for 1993, 1992 and 1991, respectively. Depreciation also includes an amount for Comanche Peak nuclear generating station (Comanche Peak) decommissioning costs which is being accrued over the lives of the units and deposited to external trust funds. (See Note 12.)

Amortization of Nuclear Fuel and Refueling Outage Costs — The amortization of nuclear fuel in the reactors (net of regulatory disallowances) is calculated on the units of production method and, subsequent to commercial operation, is included in nuclear fuel expense. The Company accrues a provision for costs anticipated to be incurred during the next scheduled Comanche Peak refueling outage.

Revenues — Revenues include billings under approved rates (including a fixed fuel factor) applied to meter readings each month on a cycle basis and, beginning January 1, 1992, an accrual of base rate revenue for energy provided after cycle billing but not billed through the end of each month (see Note 13). Revenues also include an amount for under- or over-recovery of fuel revenue representing the difference between actual fuel cost and billings on the approved fixed fuel factor and a provision that generally allows recovery through a Power Cost Recovery Factor, on a monthly basis, of the capacity portion of purchased power cost from qualifying facilities not included in base rates. The fuel portion of purchased power cost is included in the fixed fuel factor. A utility's fuel factor can be revised upward or downward every six months, according to a specified schedule. Each six months, a utility is required to petition to

1. Significant Accounting Policies — (concluded)

make either surcharges or refunds to ratepayers, together with interest based on a twelve month average of prime commercial rates, for any material cumulative under- or over-recovery of fuel costs. If the cumulative difference between the under- or over-recovery, plus interest, is in excess of 4% of the annual estimated fuel costs most recently approved by the PUC, it will be deemed to be material. A procedure exists for an expedited change in fuel factors in the event of an emergency. Final reconciliation of fuel costs must be made either in a reconciliation proceeding, which may cover no more than three years and no less than one year, or in a general rate case.

Federal Income Taxes — The Company is included in the consolidated federal income tax return of Texas Utilities Company (Texas Utilities) and its subsidiaries (System Companies) and federal income taxes are allocated to all System Companies based upon their taxable income or loss. Deferred federal income taxes are currently provided for temporary differences between book and the tax basis of assets and liabilities (including the provision for regulatory disallowances). Generally, such differences result primarily from the use of liberalized depreciation and cost recovery deductions allowable under the Internal Revenue Code, the under- or over-recovery of fuel revenue and unbilled revenues accrued for tax purposes. Temporary differences in earlier years for which deferred federal income taxes were not provided approximated $183,000,000 at December 31, 1993. Investment tax credits are normally amortized to income over the estimated service lives of the properties. For 1992 and 1991, the Company's taxes were provided for under the provisions of Accounting Principles Board Opinion No. 11, "Accounting for Income Taxes". (See Note 8 for change in accounting for income taxes.)

Cash Flows — For purposes of reporting cash flows, temporary cash investments purchased with a remaining maturity of three months or less are considered to be cash equivalents.

The supplemental schedule below details cash payments:

	Year Ended December 31,		
	1993	1992	1991
	Thousands of Dollars		
CASH PAYMENTS:			
Interest (net of amounts capitalized)	$572,208	$556,762	$605,845
Income taxes	76,933	37,714	70,325

2. Affiliates

The Company is the principal subsidiary of Texas Utilities which provides common stock capital and partial requirements for short-term financing to the Company. Texas Utilities has three other subsidiaries which perform specialized services for the System Companies, including the Company: Texas Utilities Services Inc. provides financial, accounting, computer, telecommunications, procurement, personnel, shareholder services and other administrative services at cost for which billings in 1993, 1992 and 1991 were approximately $162,735,000, $118,407,000 and $133,615,000, respectively; Texas Utilities Fuel Company (Fuel Company) owns a natural gas pipeline system, acquires, stores and delivers fuel gas and provides other fuel services at cost for the generation of electric energy by the Company, for which billings in 1993, 1992 and 1991 were approximately $901,761,000, $844,671,000 and $860,462,000, respectively; and

2. AFFILIATES — (concluded)

Texas Utilities Mining Company (Mining Company) owns, leases and operates fuel production facilities for the surface mining and recovery of lignite at cost for use at the Company's generating stations, for which billings in 1993, 1992 and 1991 were approximately $374,464,000, $382,379,000 and $368,470,000, respectively. Payments for interest on short-term financings from Texas Utilities for 1993, 1992 and 1991 were approximately $1,122,000, $4,310,000 and $3,512,000, respectively.

The Company has entered into agreements with Fuel Company to procure certain fuels and related services and with Mining Company for the procurement and production of lignite. Payments are at cost for the services received and are required by the agreements to be "at least equivalent in the aggregate to the annual charge to income on the books" of Fuel Company and of Mining Company. The Company is, in effect, obligated for the principal, $442,680,000 at December 31, 1993, and interest on long-term notes of Fuel Company and of Mining Company through payments described above. Such notes mature at various dates through 2005 and have interest rates ranging from 6.50% to 9.42%.

3. SHORT-TERM FINANCING

At December 31, 1993, the Company and Texas Utilities had joint lines of credit aggregating $700,000,000 under a credit facility agreement with a group of commercial banks. The facility, for which Texas Utilities pays a fee, is scheduled by such agreement to be reduced by $350,000,000 in June 1994 and June 1995. It is the intent of the Company and Texas Utilities to negotiate a new credit facility prior to the scheduled reduction in June 1994. The new facility would be used for working capital, as backup for commercial paper and for other corporate purposes. From time to time Texas Utilities makes short-term loans to the Company.

4. COMMON STOCK

The Company issued shares of its authorized but unissued common stock to Texas Utilities as follows:

Year	Shares	Net Proceeds
1993	3,400,000	$198,900,000
1992	7,475,000	401,162,500
1991	7,075,000	350,463,000

No shares of the Company's common stock are held by or for account of the Company, nor are any shares of such capital stock reserved for officers and employees or for options, warrants, conversions and other rights in connection therewith.

5. RETAINED EARNINGS RESTRICTIONS

The Company's articles of incorporation, its mortgages, as supplemented, and its debenture agreements contain provisions which, under certain conditions, restrict distributions on or acquisitions of its common stock. At December 31, 1993, $167,258,000 of retained earnings were thus restricted as a result of the provisions of such articles of incorporation.

5. RETAINED EARNINGS RESTRICTIONS — (concluded)

The articles of incorporation restriction provides in effect that the Company shall not pay any common dividend which would reduce retained earnings to less than one and one-half times annual preferred dividend requirements. The mortgage restrictions are based primarily on the replacement fund requirements of the mortgages. The restriction contained in the debenture agreements is designed to maintain the aggregate preferred and common stock equity at or above 33-1/3% of total capitalization.

6. **PREFERRED STOCK (cumulative, without par value, entitled upon liquidation to $100 a share; authorized 17,000,000 shares)**

Dividends From	Dividends To	Shares Outstanding December 31, 1993	Shares Outstanding December 31, 1992	Amount December 31, 1993 (Thousands of Dollars)	Amount December 31, 1992 (Thousands of Dollars)	Redemption Price Per Share (Before Adding Accumulated Dividends) Current From	Current To	Eventual Minimum From	Eventual Minimum To
Not Subject to Mandatory Redemption									
$4.00	$ 5.08	1,222,942	1,222,942	$ 122,592	$122,592	$101.79	$112.00	$101.79	$112.00
6.84	7.98	5,799,675	1,549,675	568,175	155,266	102.40	103.42	100.00	103.42
8.16	8.92	2,149,475	1,999,475	210,528	198,642	102.04	103.29	100.00	103.29
9.32	11.32	—	1,550,000	—	153,205	—	—	—	—
Adjustable rate (a)		1,850,000	1,850,000	181,713	181,713	103.00	103.00	100.00	100.00
Flexible adjustable rate		—	1,000,000	—	98,146	—	—	—	—
Total		11,022,092	9,172,092	$1,083,008	$909,564				
Subject to Mandatory Redemption (b)(c)									
$6.375	$ 6.98	2,000,000	—	$ 197,755	$ —	$ —	$ —	$100.00	$100.00
8.92	9.48	—	1,433,300	—	142,802	—	—	—	—
9.64	10.375	2,000,000	2,774,000	199,162	275,946	100.00	100.00	100.00	100.00
Total		4,000,000	4,207,300	$ 396,917	$418,748				

(a) Adjustable rate series A bears a dividend rate for the period ended January 31, 1994, of 6.50% per annum and adjustable rate series B bears a dividend rate for the period ended December 31, 1993, of 7.00% per annum, both of which are based on a fixed liquidation price of $100 per share.

(b) The Company is required to redeem at a price of $100 per share plus accumulated dividends a specified minimum number of shares annually or semi-annually on the initial/next dates shown below. These redeemable shares may be called, purchased or otherwise acquired. Certain issues may not be redeemed at the option of the Company prior to 1995. The Company may annually call for redemption, at its option, an aggregate of up to twice the number of shares shown below for each series at a price of $100 per share plus accumulated dividends, except for the $9.64 series which may be redeemed in a minimum amount of 10,000 shares at any time at a price $100 per share plus accumulated dividends plus a component at a variable price per share which is designed to maintain the expected yield at issuance:

Series	Minimum Redeemable Shares	Initial/Next Date of Mandatory Redemption
$ 9.64	125,000 semi-annually	5/1/95
10.375	150,000 annually	4/1/95
9.875	50,000 annually	10/1/96
6.98	50,000 annually	7/1/03
6.375	50,000 annually	10/1/03

6. PREFERRED STOCK (cumulative, without par value, entitled upon liquidation to $100 a share; authorized 17,000,000 shares) — (concluded)

Preferred stock mandatory redemption requirements for the next five years are $25 million in 1995 and $45 million annually in 1996, 1997 and 1998. The carrying value of preferred stock subject to mandatory redemption is being increased periodically to equal the redemption amounts at the mandatory redemption dates with a corresponding increase in preferred stock dividends.

(c) Under certain circumstances relating to a change in federal tax law governing the dividends received deduction applicable to eligible corporations, the dividend rate of the $9.64 series may increase to a maximum of $10.74.

The table below details changes in preferred stock of the Company:

Dividends From	Dividends To	Shares 1993	Shares 1992	Shares 1991	Amount 1993	Amount 1992	Amount 1991
					Thousands of Dollars		
Not subject to mandatory redemption:							
Issued:							
$7.22	$7.98	4,250,000	—	—	$ 412,909	$ —	$ —
—	8.20	1,250,000	—	—	120,759	—	—
Redeemed:							
$8.32	$ 8.92	(1,100,000)	—	—	(108,872)	—	—
9.32	11.32	(1,550,000)	—	—	(153,205)	—	—
Flexible Adjustable Rate		(1,000,000)	—	—	(98,146)	—	—
Stated Rate Auction		—	(1,000,000)	—	—	(98,164)	—
Total		1,850,000	(1,000,000)	—	$ 173,445	$(98,164)	$ —
Subject to mandatory redemption:							
Issued:							
$6.375	$6.98	2,000,000	—	—	$ 197,675	$ —	$ —
Redeemed:							
$ 8.92	$ 9.48	(1,433,300)	(40,950)	—	(142,802)	(4,095)	—
10.00	10.08	(774,000)	(34,000)	(14,000)	(77,004)	(3,400)	(1,400)
Total		(207,300)	(74,950)	(14,000)	$ (22,131)	$(7,495)	$(1,400)

7. LONG-TERM DEBT, less amounts due currently

Maturity From	Maturity To	Interest Rate From	Interest Rate To	December 31, 1993	December 31, 1992
				Thousands of Dollars	
First mortgage bonds:					
1995	1997	4-1/2%	7-1/8%	$ 474,000	$ 474,000
1998	2002	5-1/2	10-3/8	1,282,000	1,207,000
2003	2007	6-1/4	9-1/2	875,000	800,000
2008	2012	9-3/8	10.44	150,000	325,000
2015	2017	9-1/4	9-3/8	—	450,000
2018	2022	8-7/8	11-3/8	1,075,000	1,225,000
2023	2025	7-3/8	8-3/4	1,450,000	375,000
Pollution control series:					
2007	2028	5-1/2	9-7/8	1,435,060	1,136,595
Taxable pollution control series: (a)					
2021	2023	Various		278,340	228,340
Sinking fund debentures:					
—	1994	—	7-3/4	—	11,950
Secured medium-term notes, series A through C:					
1994	2003	8.72	10.50	320,000	600,000
Total				7,339,400	6,832,885
Pollution control revenue bonds:					
2004	2009	5.70	7-5/8	—	157,150
Promissory note and debt assumed for purchase of electric plant: (b)					
1993	2021	8.25	9.73	344,161	348,899
Unamortized premium and discount				(76,471)	(58,633)
Total long-term debt, less amounts due currently				$7,607,090	$7,280,301

(a) Taxable pollution control series consist of four series: $18,000,000 at 3.35% and $10,340,000 at 3.40% of flexible rate Series 1991A at December 31, 1993; $50,000,000 of Series 1991C at 8.49% through June 1, 1994; $100,000,000 of Series 1991D at 8.85% through June 1, 1995; and $100,000,000 at 3.425% of flexible rate Series 1993 at December 31, 1993. Series 1991A and Series 1993 bonds are in a flexible mode and while in such mode will be remarketed for periods of less than 270 days, and are secured by an irrevocable letter of credit with maturities in excess of one year. The interest rates on Series 1991C and Series 1991D bonds will be repriced on the mandatory tender dates of June 1, 1994 and 1995, respectively. The Company has existing lines of credit that would allow refinancing of bonds not supported by the letter of credit on a long-term basis should remarketing prove unsuccessful.

(b) In 1988, the Company purchased the ownership interest in Comanche Peak of Brazos Electric Power Cooperative and issued a promissory note payable over 33 years. The note is secured by a mortgage on the acquired interest. In 1990, the Company purchased the ownership interest in Comanche Peak of Tex-La Electric Cooperative of Texas, Inc. (Tex-La) and assumed debt of Tex-La payable over approximately 32 years. The assumption is secured by a mortgage on the acquired interest. Texas Utilities has guaranteed these various payments.

7. Long-Term Debt, less amounts due currently — (concluded)

Sinking fund and maturity requirements for the years 1994 through 1998 under long-term debt instruments in effect at December 31, 1993, were as follows:

Year	Sinking Fund	Maturity(a)	Minimum Cash Requirement(b)
	Thousands of Dollars		
1994	$15,833	$140,450	$145,188
1995	15,883	80,000	85,198
1996	15,695	96,000	[illegible]
1997	15,295	399,800	[illegible]
1998	14,342	450,000	[illegible]

(a) The maturity requirements do not include the mandatory tenders of the Company's taxable pollution control series, equal to $50,000,000 in 1994 and $100,000,000 in 1995, which are expected to be remarketed.

(b) The minimum cash requirement does not include the sinking fund requirements that may be satisfied by certification of property additions at the rate of 167% of such requirements, except for twelve issues at 100%.

From time to time, various principal amounts of first mortgage bonds have been redeemed by the Company prior to maturity. In 1993, the Company refunded $1,575,000,000 of higher coupon debt. The debt reacquisition costs have been deferred and are being amortized over the remaining lives of the bonds retired pursuant to current regulatory treatment.

Electric plant of the Company is generally subject to the liens of its mortgages.

8. Federal Income Taxes

In January 1993, the Company adopted Statement 109, which among other things, requires the liability method of recognition for all temporary differences, requires that deferred tax liabilities and assets be adjusted for an enacted change in tax laws or rates and prohibits net-of-tax accounting and reporting. Certain provisions of Statement 109 provide that regulated enterprises are permitted to recognize such adjustments as regulatory assets or liabilities if it is probable that such amounts will be recovered from or returned to customers in future rates. Accordingly, at December 31, 1993, the Company's balance sheet reflects a regulatory asset of approximately $1.2 billion net of an approximate $0.6 billion regulatory liability. The cumulative effect on net income of adopting Statement 109 is not considered material to the annual results of operation.

In August 1993, Congress passed the Revenue Reconciliation Act of 1993 which increased the top corporate income tax rate from 34% to 35% retroactive to January 1, 1993.

8. **Federal Income Taxes — (continued)**

The details of federal income taxes are as follows:

	Year Ended December 31, 1993	1992	1991
	Thousands of Dollars		
Charged (credited) to operating expenses:			
Current	$ 127,169	$ 50,616	$ 80,751
Deferred — net:			
Differences between depreciation methods and lives	208,322	185,246	222,766
Certain capitalized construction costs	33,251	5,189	2,706
Under-recovered fuel revenue	43,436	13,371	14,800
Early redemptions of long-term debt	22,944	35,543	3,364
Benefit plans	(247)	(4,891)	(3,858)
Unbilled revenues	(11,990)	(4,568)	277
Alternative minimum tax	(88,529)	(46,714)	(64,784)
Investment tax credit carryforward	25,403	9,451	16,243
Amortization of tax rate differences	17,316	(2,093)	(20,336)
Provision for refunds and related interest — net	(39,871)	6,282	(15,541)
Prior year adjustments	(1,475)	1,428	(18,883)
Net operating loss carryforward	22,954	(60,554)	(46,595)
Voluntary retirement/severance costs	1,970	29,400	—
Other	2,530	310	(4,629)
Total	236,014	167,400	85,530
Investment tax credits — net	(19,698)	(20,322)	(13,318)
Total to operating expenses	343,485	197,694	152,963
Charged (credited) to other income:			
Current	(30,218)	(21,567)	(4,678)
Deferred — net:			
Regulatory disallowances	(102,034)	—	(327,178)
Amortization of regulatory disallowances	29,477	22,883	8,787
Other	1,030	1,163	397
Total	(71,527)	24,046	(317,994)
Investment tax credits — regulatory disallowances	—	—	(40,180)
Total to other income	(101,745)	2,479	(362,852)
Charged to cumulative effect of a change in accounting for unbilled revenue — deferred	—	41,679	—
Total federal income taxes	$ 241,740	$241,852	$(209,889)

8. FEDERAL INCOME TAXES — (continued)

The significant components of the Company's deferred tax assets and liabilities reflected net in the balance sheet at December 31, 1993 are:

	Thousands of Dollars
DEFERRED TAX ASSETS	
Current:	
Unbilled revenues	$ 38,684
Bad debt reserve	4,941
Total current	$ 43,625
Non-Current:	
Unamortized ITC	$ 365,063
Regulatory disallowances	318,025
Alternative minimum tax	335,177
Tax rate differences	93,238
NOL carryforward	91,750
ITC carryforward	5,171
Combustion turbine leases	10,338
Refunds and interest	49,403
Benefit plans	12,305
Property insurance reserve	(1,090)
Other	4,286
Total non-current	1,283,666
DEFERRED TAX LIABILITIES	
Non-Current:	
Capitalized construction costs	2,106,433
Differences between depreciation methods and lives	1,383,086
Previous flow-through differences	96,922
Unamortized debt reacquisition costs	97,930
Under-recovered fuel revenue	71,666
Voluntary retirement/severance costs	25,046
Lignite depletion	27,261
Rate case costs	24,089
Nuclear fuel basis differences	12,294
Intangible plant	8,113
Cancelled lignite unit costs	8,815
Total deferred tax liability	3,861,655
NET TOTAL NON-CURRENT DEFERRED TAX LIABILITY	$2,577,989

8. FEDERAL INCOME TAXES — (concluded)

Federal income taxes were less than the amount computed by applying the federal statutory rate to pre-tax book income (loss) as follows:

	Year Ended December 31,		
	1993	1992	1991
	Thousands of Dollars		
Federal income taxes at statutory rate: 1993 — 35%; 1992 and 1991 — 34%	$251,393	$361,411	$(169,681)
Reductions in federal income taxes resulting from:			
Allowance for funds used during construction	52,540	98,221	118,603
Depletion allowance	22,696	22,014	21,104
Amortization of investment tax credits	19,698	20,322	20,401
Amortization of tax rate differences	(17,316)	2,093	20,336
Reversal of prior book/tax differences:			
Regulatory disallowances	(21,553)	—	(142,412)
Investment tax credit — regulatory disallowances	—	—	40,180
Other	(27,454)	(24,159)	(23,278)
Prior year adjustments	334	949	(11,694)
Other	(19,292)	119	(3,032)
Total reductions	9,653	119,559	40,208
Total federal income taxes	$241,740	$241,852	$(209,889)
Effective tax rate	33.7%	22.8%	42.1%

The Company has net operating loss carryforwards of approximately $261 million that are available to offset future ordinary taxable income. Approximately $71 million of these loss carryforwards expire in 2006 and the remaining $190 million expire in 2007. In addition, the Company has approximately $12 million of general business credit carryforwards which expire in 2006 and $335 million of minimum tax credit carryforwards which are available to offset future taxes.

As a part of its ongoing large case audit program, the Internal Revenue Service (IRS) is currently auditing the consolidated Federal income tax returns of the Company for the years 1987 through 1990. During the course of the audit, the IRS has proposed a number of adjustments to the returns as filed, the most significant of which relates to a proposed reclassification of certain costs incurred in connection with the construction of Comanche Peak Unit 1 as costs incurred to procure a nuclear operating license. The Company is unable to predict the ultimate resolution of the issues raised in the audit and therefore is unable to predict at this time the amount of any additional tax payment which may be required. While the making of additional tax payments would have an impact on the Company's cash position, the Company does not expect the outcome of the audit to have a material effect on its results of operation.

9. RETIREMENT PLAN AND OTHER POSTRETIREMENT BENEFITS

The Company has a retirement plan covering substantially all employees. An employee's benefits are based on years of accredited service and average annual earnings received during the three years of highest earnings. The costs of the plan were determined by independent actuaries. Contributions to the plan were determined using the frozen attained age method which is one of the several actuarial methods allowed by the Employee Retirement Income Security Act of 1974. For financial reporting purposes, pension cost has been determined using the projected unit credit actuarial method. The cumulative

9. RETIREMENT PLAN AND OTHER POSTRETIREMENT BENEFITS — (continued)

difference between pension cost as determined for financial reporting purposes and contributions to the plan is recorded either as prepaid pension cost or as accrued pension liability.

The table below details the plan's funded status and amount recognized in the Company's balance sheets:

	December 31,	
	1993	1992
	Thousands of Dollars	
Actuarial present value of accumulated benefits:		
Accumulated benefit obligation (including vested benefits of $551,103,000 for 1993 and $512,658,000 for 1992)	$(589,201)	$(543,318)
Projected benefit obligation for service rendered to date	$(720,415)	$(641,734)
Plan assets at fair value — primarily equity investments, government bonds and corporate bonds	736,443	660,776
Plan assets in excess of projected benefit obligation	16,028	19,042
Unrecognized net gain from past experience different from that assumed and effects of changes in assumptions	(131,592)	(158,456)
Prior service cost not yet recognized in net periodic pension expense	20,295	21,839
Unrecognized plan assets in excess of projected benefit obligation at initial application	(4,641)	(5,079)
Accrued pension cost	$ (99,910)	$(122,654)

Assumptions used in determination of the projected benefit obligation include the following:

	1993	1992
Discount rate	7.875%	8.50%
Increase in compensation levels	4.700%	4.70%

Total pension costs, including amounts deferred and capitalized, were comprised of the following components:

	Year Ended December 31,		
	1993	1992	1991
	Thousands of Dollars		
Service cost — benefits earned during the period	$ 17,764	$ 23,838	$ 23,860
Interest cost on projected benefit obligation	52,695	61,573	58,118
Actual return on plan assets	(80,495)	(71,043)	(207,126)
Net amortization and deferral	32,465	(1,285)	136,494
Net periodic pension cost	22,429	13,083	11,346
Deferred termination cost	—	116,665	—
Total pension cost	$ 22,429	$129,748	$ 11,346

The assumed long-term rate of return on plan assets was 8.75% for 1993, 1992 and 1991.

In addition to the retirement plan, the Company offers certain health care and life insurance benefits to substantially all its employees and their eligible dependents at retirement which normally is age 65 but may be as early as age 55 with 15 years of service. Retirees currently pay a portion of the cost of providing such benefits and are expected to continue to do so in the future. In January 1993, the Company adopted Statement of Financial Accounting Standards No. 106, "Employers' Accounting for

9. RETIREMENT PLAN AND OTHER POSTRETIREMENT BENEFITS — (concluded)

Postretirement Benefits Other Than Pensions" (Statement 106), which requires a change in the accounting for a company's obligation to provide health care and certain other benefits to its retirees from the "pay-as-you-go" method to an accrual method and requires the cost of the obligation to be recognized in the period from employment date until full eligibility for benefits.

The Company's net periodic postretirement benefits cost other than pensions for the year ended December 31, 1993, including amounts capitalized, were comprised of the following components:

	Thousands of Dollars
Service cost — benefits earned during the period	$ 5,642
Interest cost on the accumulated postretirement benefit obligation	25,677
Amortization of the transition obligation	15,058
Actual return on plan assets	—
Net amortization and deferral	—
Net postretirement benefits cost	$46,377

The table below details the funded status for other postretirement benefits and amount recognized by the Company at December 31, 1993:

	Thousands of Dollars
Accumulated postretirement benefit obligation (APBO):	
Retirees	$(224,116)
Fully eligible active employees	(3,796)
Other active employees	(121,687)
Total APBO	(349,599)
Plan assets at fair value	—
APBO in excess of plan assets	(349,599)
Unrecognized net loss	40,087
Unrecognized prior service cost	—
Unrecognized transition obligation	286,093
Accrued postretirement benefits cost	$ (23,419)

The expected increase in costs of future benefits covered by the plan is projected using a health care cost trend rate of 7.5% in 1994, 6.5% in 1995, 5.5% in 1996 and 5.0% in 1997 and thereafter. A one percentage point increase in the assumed health care cost trend rate in each future year would increase the APBO at December 31, 1993 by approximately $51.7 million and other postretirement benefits cost for 1993 by approximately $6.5 million.

The assumed discount rate used to measure the APBO is 7.875%.

The Company's cost of providing other postretirement benefits in 1992 and 1991, which was recognized on a "pay-as-you-go" basis, was approximately $13,002,000 and $13,781,000, respectively. The Company was granted recovery of its Statement 106 cost in Docket 11735 (see Note 11). Funding of the other postretirement benefits obligation will begin by the third quarter of 1994.

10. Sales of Accounts Receivable

In November 1993, the Company terminated its then existing receivables facility to sell receivables to certain financial institutions and entered into a new facility with other financial institutions. Under such new facility, the Company is entitled to sell and such financial institutions may purchase, on an ongoing basis, undivided interests in customer accounts receivable representing up to an aggregate of $350,000,000. Additional receivables are continually sold to replace those collected. At December 31, 1993 and 1992, accounts receivable was reduced by $300,000,000 to reflect the sales of such receivables to financial institutions under such agreements.

11. Rate Proceedings

Docket 11735

In January 1993, the Company made applications to the PUC in Docket 11735 and to its municipal regulatory authorities for upward adjustments in rates for electric service throughout its service area, which would have increased annual operating revenues by approximately $760 million, or 15.3%, based upon the test year ended June 30, 1992. Such request reflects, among other things, costs associated with Comanche Peak Unit 2, costs associated with Comanche Peak Unit 1 after the end of the Docket 9300 (see below) test year, additional ad valorem taxes and certain postretirement benefit costs. In August 1993, pursuant to rules of the PUC, the Company placed its requested rate increase into effect, under bond and subject to refund with interest, applicable to energy sales on and after such date. Revenues were recorded net of an estimated reserve for possible refunds.

In October 1993, the PUC issued an order (Order) approving the terms of an agreement (Settlement Agreement) among the Company, the General Counsel's office of the PUC and applicable intervenors which, among other things, settled all remaining issues relating to the design, construction and cost of Comanche Peak through commencement of commercial operation of Unit 2. The Settlement Agreement provides for the disallowance in Docket 11735 of $250 million of costs relating to the completion of Comanche Peak. Pursuant to the Order, the Company refunded $5 million in fuel charges previously incurred in order to resolve the fuel phase of Docket 11735 under which the Company was seeking reconciliation of approximately $4.6 billion of fuel costs incurred during the three year period ended June 30, 1992, under the fuel rule in effect prior to May 1993. Further, in order to resolve the primary issue in another proceeding which resulted from a complaint filed against the Company in October 1992 by the General Counsel's office of the PUC, as a result of the Order, the Company agreed to write off $83 million of AFUDC, which consists of the amount subject to dispute in such proceeding and similar charges subsequently accrued. Also, under the Settlement Agreement and confirmed in the Docket 11735 final order (see below), the Company will recover, ratably over an eight year period, $197 million of operation and maintenance expenditures incurred by the Company in connection with its recent cost reduction program. However, an additional $25 million of such expenditures will not be subject to recovery and was written off by the Company. As a result of the Settlement Agreement, the Company recorded a charge against earnings in September 1993 of approximately $363 million ($265 million after tax).

11. RATE PROCEEDINGS — (continued)

On January 28, 1994, the PUC issued a final order in Docket 11735 which provided for a total annual revenue increase of approximately $435 million, or 8.7%. The Company strongly disagrees with the final order and has filed a motion for rehearing with the PUC, and will appeal the outcome, if necessary. As a result of this order, unless the order is changed on rehearing, the Company will refund the difference between the bonded rates and the rates approved in the final order, including interest, all of which is being fully reserved by the Company. The total amount to be refunded will be determined once approved rates have been implemented, which is expected to be during the second quarter of 1994. The amount to be refunded at December 31, 1993 was approximately $141.2 million. Such refund will be mitigated by a fuel cost surcharge approved by the PUC of approximately $144.5 million, including interest, in under-collected fuel costs through June 30, 1993.

The following details the effect on 1993 net income of the Settlement Agreement and the Docket 11735 final order charges:

	Thousands of Dollars
OPERATING REVENUES	$ (5,000)
OPERATING EXPENSES	
Federal income taxes — current	1,000
Federal income taxes — deferred	750
OPERATING INCOME	(3,250)
OTHER INCOME (LOSS)	
Regulatory disallowances	(359,556)
Federal income taxes — current	2,258
Federal income taxes — deferred	94,406
Total other income (loss)	(262,892)
EFFECT ON NET INCOME	$(266,142)

In November 1993, an intermediate appellate court in Texas, considering an appeal of another utility's rate case, ruled that utilizing tax benefits generated by costs not allowed in rates to reduce rates charged to customers was required by prior court rulings for all disallowed costs, including capital costs. The Company believes that such rulings are erroneous and not consistent with the Texas Public Utility Regulatory Act. According to a Private Letter Ruling issued to the Company by the Internal Revenue Service (IRS) with respect to investment tax credits, such ratemaking treatment, to the extent related to property classified for tax purposes as public utility property, would result in a violation of the normalization rules contained in the Internal Revenue Code of 1986, as amended (Code). Violation of the normalization rules would result in a significant adverse effect on the Company's results of operation and liquidity. The tax benefits associated with the Comanche Peak costs disallowed in Docket 9300 (see below) could be affected as a result of the court's method. In addition, in its final order in Docket 11735, the PUC reduced rates for the tax benefits generated by certain costs which were not allowed in rates. However, the PUC recognized the potential for a normalization violation if investment tax credits and tax depreciation generated by disallowed plant costs are used to reduce rates. Therefore, the PUC ordered the Company to obtain a Private Letter Ruling from the IRS with respect to tax depreciation on disallowed plant. Thus, the Company's rates would not reflect the tax depreciation benefit of disallowed plant unless the IRS rules such benefits can be utilized to reduce rates without violating the normalization rules contained in the Code. Such a finding by the IRS would require the Company to refund the tax

11. RATE PROCEEDINGS — (concluded)

depreciation benefits to its customers. The Company does not believe it is likely that such refund will occur if the IRS maintains a position similar to that stated in its previous Private Letter Ruling to the Company.

Docket 9300

In September 1991, the PUC issued a final order in Docket 9300, which provided for a total revenue increase of approximately $442 million and included $695 million of CWIP in rate base to support the revenue increase. It also included a prudence disallowance of $472 million with respect to certain Comanche Peak costs relating to 87.8% of the Company's ownership interest in both units of Comanche Peak. With respect to the Company's reacquisition of the remaining 12.2% minority owner interests in Comanche Peak, the order included an additional disallowance of $909 million. In September 1991, the Company recorded a charge against earnings, as a provision for regulatory disallowances, of $1.381 billion ($1.011 billion after tax) as a result of the Docket 9300 final order.

In November 1991, the Company filed a petition in the 250th Judicial District Court of Travis County, Texas, requesting a reversal and remand of the Docket 9300 final order. Other parties to the PUC proceeding also filed appeals with respect to various portions of the order. In September 1992, after a hearing, the Court entered a judgment in the appeals which affirmed the prudence disallowance of $472 million but reversed and remanded to the PUC for reconsideration those portions of the PUC's final order providing for additional disallowances aggregating $884 million with respect to the Company's reacquisition of minority owner interests in Comanche Peak. The Court recognized that on remand the PUC may adjust the amount of CWIP included in the Company's rate base to be consistent with the PUC's redeterminations regarding the minority owner reacquisitions and the amount of cash working capital. Therefore, the Company does not expect this judgment to affect the rates approved in the Docket 9300 final order. Other parties to this suit have appealed this judgment. The Company disagrees with certain portions of the judgment and also has appealed. The Company is unable to predict the outcome of such appeals and any reconsideration by the PUC.

12. COMMITMENTS AND CONTINGENCIES

Construction Program

The Company has taken steps to substantially reduce construction expenditures from amounts previously estimated. Construction expenditures, excluding AFUDC, are presently estimated at $363 million for each of the years 1994, 1995 and 1996. Estimated construction expenditures for 1994 through 1996 do not include $210 million in 1996 to resume active construction of two lignite-fueled units at Twin Oak which would be necessary to meet the current scheduled in service dates of the units. The reevaluation of growth expectations, the effects of inflation, additional regulatory requirements, and the availability of fuel, labor, materials and capital may result in changes in estimated construction costs and dates of completion. Commitments in connection with the construction program are generally revocable subject to reimbursement to manufacturers for expenditures incurred or other cancellation penalties.

12. COMMITMENTS AND CONTINGENCIES — (continued)

Clean Air Act

The federal Clean Air Act, as amended (Clean Air Act) includes provisions which, among other things, place limits on the sulfur dioxide emissions produced by generating units. To meet these sulfur dioxide requirements, the Clean Air Act provides for the annual allocation of sulfur dioxide emission allowances to utilities. Under the Clean Air Act, utilities are permitted to transfer allowances within their own systems and to buy or sell allowances. The EPA grants a maximum number of allowances annually to the Company based on the amount of emissions from units in operation during the period 1985 through 1987. The Clean Air Act also provides that the Company be granted additional annual allowances for certain of the Company's units under construction based on part of their anticipated emissions. The Company's capital requirements have not been significantly affected by the requirements of the Clean Air Act. Although the Company is unable to fully determine the cost of compliance with the Clean Air Act, it is not expected to have a significant impact on the Company. Any additional capital costs, as well as any increased operating costs associated with these new requirements, are expected to be recoverable through rates, as similar costs have been recovered in the past.

Purchased Power Contracts

The Company has entered into purchased power contracts to purchase portions of the generating output of certain qualifying cogenerators and qualifying small power producers through the year 2005. These contracts provide for capacity payments subject to a facility meeting certain operating standards and energy payments based on the actual power taken under the contracts. The cost of these and other purchased power contracts is recovered currently through base rates, power cost and fuel recovery factors applied to customer billings. Capacity payments under these contracts for the years ended December 31, 1993, 1992 and 1991 were $249,110,000, $240,341,000 and $229,953,000, respectively.

Assuming operating standards are achieved, future capacity payments under the agreements are estimated as follows:

Years	Thousands of Dollars
1994	$ 231,081
1995	223,910
1996	228,337
1997	237,014
1998	244,795
Thereafter	654,641
Total	$1,819,778

Leases

The Company has entered into operating leases covering various facilities and properties including combustion turbines, transportation, mining and data processing equipment, and office space. Lease costs charged to operation expense for the years ended December 31, 1993, 1992 and 1991 were $68,311,000, $66,219,000 and $60,085,000, respectively.

12. COMMITMENTS AND CONTINGENCIES — (continued)

The Company's future minimum lease commitments under such operating leases that have initial or remaining noncancellable lease terms in excess of one year as of December 31, 1993, were as follows:

Years	Thousands of Dollars
1994	$ 34,961
1995	33,079
1996	31,387
1997	29,884
1998	29,313
Thereafter	595,608
Total minimum lease commitments*	$754,232

* Minimum lease commitments have not been reduced by $46,000 due to the Company under noncancellable subleases.

Cooling Water Contracts

The Company has entered into contracts with public agencies to purchase cooling water for use in the generation of electric energy. In connection with certain contracts, the Company has agreed, in effect, to guarantee the principal, $38,590,000 at December 31, 1993, and interest on bonds issued to finance the reservoirs from which the water is supplied. The bonds mature at various dates through 2011 and have interest rates ranging from 5-1/2 to 7%. The Company is required to make periodic payments equal to such principal and interest for the years 1994 through 1998 which includes amounts assumed by a third party as follows: $4,423,000 for 1994; $4,431,000 for 1995; $4,430,000 for 1996; $4,435,000 for 1997 and $4,435,000 for 1998. Payments made by the Company, net of amounts assumed by a third party under such contracts, for 1993, 1992 and 1991 were $2,954,000, $2,849,000 and $2,596,000, respectively. In addition, the Company is obligated to pay certain variable costs of operating and maintaining the reservoirs. The Company has assigned to a municipality all contract rights and obligations of the Company in connection with $86,450,000 remaining principal amount of bonds at December 31, 1993, issued for similar purposes which had previously been guaranteed by the Company. The Company is, however, contingently liable in the unlikely event of default by the municipality.

Nuclear Insurance

With regard to liability coverage, the Price-Anderson Act (Act) provides financial protection for the public in the event of a significant nuclear power plant incident. The Act sets the statutory limit of public liability for a single nuclear incident currently at $9.4 billion and requires nuclear power plant operators to provide financial protection for this amount. As required, the Company provides this financial protection for a nuclear incident at Comanche Peak resulting in public bodily injury and property damage through a combination of private insurance and industry-wide retrospective payment plans. As the first layer of financial protection, the Company has purchased $200 million of liability insurance from American Nuclear Insurers (ANI), which provides such insurance on behalf of two major stock and mutual insurance pools, Nuclear Energy Liability Insurance Association and Mutual Atomic Energy Liability Underwriters. The second layer of financial protection is provided under an industry retro-

12. COMMITMENTS AND CONTINGENCIES — (continued)

spective payment program called Secondary Financial Protection (SFP). Under the SFP, each operating licensed reactor in the United States is subject to an assessment of up to $79.275 million, subject to increases for inflation every five years, in the event of a nuclear incident at any nuclear plant in the United States. Assessments are limited to $10 million per operating licensed reactor per year per incident. All assessments under the SFP are subject to a 3% insurance premium tax which is not included in the amounts above.

With respect to nuclear decontamination and property damage insurance, NRC regulations require that nuclear plant license-holders maintain not less than $1.06 billion of such insurance and require the proceeds thereof to be used to place a plant in a safe and stable condition, to decontaminate it pursuant to a plan submitted to and approved by the NRC before the proceeds can be used for plant repair or restoration or to provide for premature decommissioning. The Company maintains nuclear decontamination and property damage insurance for Comanche Peak in the amount of $2.75 billion, above which the Company is self-insured. The primary layer of coverage of $500 million is provided by ANI. The remaining coverage includes premature decommissioning coverage and is provided by ANI in the amount of $850 million and Nuclear Electric Insurance Limited (NEIL), a nuclear electric utility industry mutual insurance company, in the amount of $1.4 billion. The Company is subject to a maximum annual assessment from NEIL of $17 million in the event NEIL's losses under this type of insurance for major incidents at nuclear plants participating in this program exceed its accumulated funds and reinsurance.

The Company maintains Extra Expense Insurance through NEIL to cover the additional costs of obtaining replacement power from another source if one or both of the units at Comanche Peak are out of service for more than twenty-one weeks as a result of covered direct physical damage. The coverage provides for weekly payments of up to $3.5 million for the first and $2.345 million for the second and third fifty-two week periods of each outage, respectively, after the initial twenty-one week period. The total maximum coverage is $426 million per unit. The coverage amounts applicable to each unit will be reduced to 80% if both units are out of service at the same time as a result of the same accident. Under this coverage, the Company is subject to a maximum assessment of $10 million per year.

Nuclear Decommissioning and Disposal of Spent Fuel

The Company has established a reserve (included in accumulated depreciation) for the decommissioning of Comanche Peak, whereby decommissioning costs are being recovered from customers over the life of the plant and deposited in external trust funds (included in other investments). At December 31, 1993, such reserve totaled $35,978,000 which includes an accrual of $12,612,000 for the year ended December 31, 1993. At December 31, 1993, $35,720,000 has been deposited in the external trust funds for decommissioning of Unit 1 and Unit 2. Realized earnings on funds deposited in the external trust are recognized in the reserve. Based on a site-specific study during 1992 using the prompt dismantlement method and then-current dollars, decommissioning costs for Comanche Peak Unit 1, and Unit 2 and common facilities were estimated to be $255,000,000 and $344,000,000, respectively. Decommissioning activities are projected to begin in 2030 and 2032 for Comanche Peak Unit 1, and Unit 2 and common facilities, respectively. The Company is recovering such costs based upon the 1992 study through the rates placed in effect under Docket 11735 (see Note 11).

12. COMMITMENTS AND CONTINGENCIES — (concluded)

The Company has a contract with the United States Department of Energy for the future disposal of spent nuclear fuel at a cost of one mill per kilowatt-hour of Comanche Peak net generation. The disposal fee is included in nuclear fuel expense.

General

In addition to the above, the Company is involved in various legal and administrative proceedings which, in the opinion of the Company, should not have a material effect upon its financial position or results of operation.

13. CHANGE IN ACCOUNTING FOR UNBILLED REVENUE

Effective January 1, 1992, the Company began recording base rate revenue for energy sold but not billed through the end of each month to achieve a better matching of revenues and expenses. Prior to the change in accounting method, revenues were recognized based on customer billings on a cycle basis. The change in accounting increased net income in 1992 by $102,044,000, of which $80,907,000 represents the cumulative effect of the change in accounting principle at January 1, 1992. Pro forma effects, assuming retroactive application of recording unbilled revenues, are presented below:

	Year Ended December 31,		
	1993	1992	1991
	Thousands of Dollars		
As previously reported:			
Net income (loss)	$476,526	$821,123	$(289,173)
Pro forma:			
Net income (loss)	—	$740,216	$(286,457)

14. FAIR VALUE OF FINANCIAL INSTRUMENTS

In December 1991, the FASB issued Statement of Financial Accounting Standards No. 107, "Disclosures about Fair Value of Financial Instruments" (Statement 107) to provide readers of the financial statements another method of valuing financial instruments on a current basis. The following information represents the Company's estimate of the amount at which the instruments could be exchanged in a current transaction between willing parties, other than in a forced sale.

The amounts reflected in the balance sheet for cash, temporary cash investments and special deposits approximate fair value due to the short maturity of such instruments. The fair values of financial instruments for which estimated fair values have not been specifically presented is not materially different than their related book value.

Other investments includes amounts principally for nuclear decommissioning fund assets and funds invested pursuant to certain incentive and compensation agreements. The fair values of the nuclear decommissioning assets and incentive and compensation assets are estimated based on quoted market prices at year-end for the instruments in which such funds are invested.

The fair values of the long-term debt and preferred stock subject to mandatory redemption are estimated at the lesser of the Company's call price or the present value of future cash flows discounted at rates consistent with comparable maturities adjusted for credit risk.

14. FAIR VALUE OF FINANCIAL INSTRUMENTS — (concluded)

The carrying amount of other financial liabilities classified as current on the balance sheet, such as notes payable-banks and long-term debt due currently, approximates fair value due to the short maturity of such instruments. Customer deposits have no defined maturities and, therefore, are reflected at the amount payable on demand at the balance sheet date.

The Company has agreed, in effect, to guarantee the principal and interest on bonds used to finance the reservoirs from which the Company uses cooling water for certain generating units. The Company is also the guarantor for the principal amount of certain bonds issued for similar purposes which were assigned to a municipality. The outstanding principal at December 31, 1993 and 1992 of the bonds for which the Company is contingently liable is $125,000,000 and $131,000,000, respectively. The fair value of the bonds, approximately $136,000,000 and $131,000,000 for December 31, 1993 and 1992, respectively, is based on the present value of the instruments' approximate cash flows discounted at the year end risk free rate for issues of comparable maturities adjusted for credit risk.

The Company is in effect obligated for the long-term notes of Fuel Company and Mining Company which total $442,680,000 and $359,150,000 at December 31, 1993 and 1992, respectively. The fair value of such notes, approximately $460,724,000 and $390,423,000 at December 31, 1993 and 1992, respectively, is calculated as the present value of the instruments' future cash flows discounted at the year end risk free rate for issues of comparable maturities adjusted for credit risk.

The estimated fair value of the Company's significant financial instruments are as follows:

	December 31, 1993		December 31, 1992	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Thousands of Dollars			
Long-term debt	$7,607,090	$8,481,960	$7,280,301	$7,976,303
Preferred stock subject to mandatory redemption	396,917	408,347	418,748	445,009
Other investments	44,564	46,278	31,620	32,623

15. SUPPLEMENTARY FINANCIAL INFORMATION (Unaudited)

In the opinion of the Company, the information below includes all adjustments (constituting only normal recurring accruals and the change in accounting, see Note 13) necessary to a fair statement of such amounts. Quarterly results are not necessarily indicative of expectations for a full year's operations because of seasonal and other factors, including rate changes, variations in maintenance and other operating expense patterns, the impact of the change in AFUDC accruals (see Note 1) and the charges for regulatory disallowances. For additional information regarding the charges for regulatory disallowances, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation and Note 11.

	Operating Revenues		Operating Income		Net Income	
Quarter Ended	1993	1992	1993	1992	1993	1992
	Thousands of Dollars					
March 31	$1,142,184	$1,056,920	$ 234,244	$ 218,249	$162,992	$196,907
June 30	1,255,657	1,195,775	264,607	281,85[illegible]	197,063	187,757
September 30	1,773,420	1,478,148	453,509	410,248	84,929	325,488
December 31	1,237,895	1,175,852	195,614	209,081	31,542	110,971
	$5,409,156	$4,906,695	$1,147,974	$1,119,431	$476,526	$821,123

INDEPENDENT AUDITORS' REPORT

Texas Utilities Electric Company:

We have audited the accompanying balance sheets of Texas Utilities Electric Company as of December 31, 1993 and 1992, and the related statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1993. Our audits also included the financial statement schedules listed in Item 14.(a)2. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedules based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes 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 financial statements present fairly, in all material respects, the financial position of the Company at December 31, 1993 and 1992, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1993, in conformity with generally accepted accounting principles. Also, in our opinion, such financial statement schedules, when considered in relation to the basic financial statements taken as a whole, present fairly in all material respects the information set forth therein.

As discussed in Notes 8 and 9 to the financial statements, in 1993, the Company changed its methods of accounting for income taxes and postretirement benefits other than pensions to conform with Statements of Financial Accounting Standards No. 109 and No. 106, respectively. Also discussed in Note 13 to the financial statements, in 1992, the Company changed its method of accounting for base rate revenue sold but not billed.

DELOITTE & TOUCHE

Dallas, Texas
March 11, 1994

TEXAS UTILITIES ELECTRIC COMPANY

STATEMENT OF RESPONSIBILITY

The management of Texas Utilities Electric Company is responsible for the preparation, integrity and objectivity of the financial statements of the Company and other information included in this report. The financial statements have been prepared in conformity with generally accepted accounting principles. As appropriate, the statements include amounts based on informed estimates and judgments of management.

The management of the Company has established and maintains a system of internal control designed to provide reasonable assurance, on a cost-effective basis, that assets are safeguarded, transactions are executed in accordance with management's authorization and financial records are reliable for preparing financial statements. Management believes that the system of control provides reasonable assurance that errors or irregularities that could be material to the financial statements are prevented or would be detected within a timely period. Key elements in this system include the effective communication of established written policies and procedures, selection and training of qualified personnel and organizational arrangements that provide an appropriate division of responsibility. This system of control is augmented by an ongoing internal audit program designed to evaluate its adequacy and effectiveness. Management considers the recommendations of the internal auditors and independent certified public accountants concerning the Company's system of internal control and takes appropriate actions which are cost-effective in the circumstances. Management believes that, as of December 31, 1993, the Company's system of internal control was adequate to accomplish the objectives discussed herein.

The independent certified public accounting firm of Deloitte & Touche is engaged to audit, in accordance with generally accepted auditing standards, the financial statements of the Company and to issue their report thereon.

/s/ ERLE NYE
Erle Nye, Chairman of the Board
and Chief Executive

/s/ H. JARRELL GIBBS
H. Jarrell Gibbs, Executive Vice President
and Principal Financial Officer

/s/ H. DAN FARELL
H. Dan Farell, Vice President
and Controller

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

PART III

Item 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT.

Identification of directors, business experience and other directorships:

Name	Age	Other Positions and Offices Presently Held With the Company (Current Term Expires May 20, 1994)	Date First Elected as Director	Present Principal Occupation or Employment and Principal Business (preceding 5 yrs.), Other Directorships
T. L. Baker	48	Executive Vice President	February 20, 1987	Executive Vice President of the Company; prior thereto, Senior Vice President of the Company.
J. S. Farrington	59	None	September 17, 1982	Chairman of the Board and Chief Executive of Texas Utilities, the parent company of the Company; other directorships: Texas Utilities.
H. Jarrell Gibbs	56	Executive Vice President	May 24, 1989	Vice President and Principal Financial Officer of Texas Utilities and Executive Vice President of the Company; prior thereto, Executive Vice President of Texas Electric Service Division; prior thereto, Vice President of the Company.
Erle Nye	56	Chairman and Chief Executive	September 17, 1982	President of Texas Utilities; other directorships: Texas Utilities.
Michael D. Spence	52	Executive Vice President	September 17, 1982	Executive Vice President of the Company; prior thereto, President of Generating Division.
W. M. Taylor	51	Executive Vice President	May 20, 1986	Executive Vice President of the Company; prior thereto, President of Dallas Power Division.
E. L. Watson	59	Vice Chairman	February 20, 1987	Vice Chairman of the Company; prior thereto, Executive Vice President of the Company; prior thereto, Senior Vice President of the Company.

Item 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT (Concluded).

Identification of executive officers and business experience:

Name of Officer	Age	Positions and Offices Presently Held (Current Term Expires May 20, 1994)	Date First Elected to Present Offices	Business Experience (Preceding Five Years)
Erle Nye	56	Chairman and Chief Executive	February 20, 1987	Same and President of Texas Utilities.
T. L. Baker	48	Executive Vice President	October 1, 1991	Senior Vice President of the Company.
H. Jarrell Gibbs	56	Executive Vice President	October 1, 1991	Vice President and Principal Financial Officer of Texas Utilities; prior thereto, Executive Vice President of Texas Electric Service Division; prior thereto, Vice President of the Company.
Michael D. Spence	52	Executive Vice President	October 1, 1991	President of Generating Division.
W. M. Taylor	51	Executive Vice President	October 1, 1991	President of Dallas Power Division.
E. L. Watson	59	Vice Chairman	November 1, 1992	Executive Vice President; prior thereto, Senior Vice President of the Company.

There is no family relationship between any of the above named executive officers.

Item 11. FXECUTIVE COMPENSATION

The Company has paid or awarded compensation during the last three calendar years to the following executive officers for services in all capacities:

SUMMARY COMPENSATION TABLE

		Annual Compensation			Long-Term Compensation (2)			
					Awards		Payouts	
Name and Principal Position	Year	Salary ($)	Bonus ($)	Other Annual Compensation ($)	Restricted Stock Awards ($)	Options/ SARs (#)	LTIP Payouts ($)	All Other Compensation ($) (3)
Erle Nye, Chairman of the Board and Chief Executive of the Company (1)	1993	554,167	100,000	-	203,500	-	61,938	63,907
	1992	525,000	0	-	194,500	-	50,266	60,739
	1991	493,750	0	-	169,500	-	0	NA
Michael D. Spence, Executive Vice President of the Company	1993	289,083	31,000	-	67,560	-	44,034	34,246
	1992	285,000	0	-	66,300	-	33,223	22,800
	1991	285,000	40,000	-	81,300	-	0	NA
T. L. Baker, Executive Vice President of the Company	1993	237,083	25,000	-	58,200	-	29,720	26,042
	1992	233,000	0	-	56,940	-	24,404	25,112
	1991	223,417	0	-	61,940	-	0	NA
W. M. Taylor, Executive Vice President of the Company	1993	217,250	65,000	-	60,800	-	28,815	21,296
	1992	205,000	0	-	66,900	-	22,543	12,795
	1991	198,750	0	-	51,900	-	0	NA
E. L. Watson, Vice Chairman of the Company	1993	227,000	27,000	-	56,760	-	29,682	28,944
	1992	220,000	0	-	54,600	-	23,920	28,146
	1991	213,333	0	-	56,600	-	0	NA

(1) Amounts reported in the table consist entirely of compensation paid by Texas Utilities.

(2) Amounts reported as Long-Term Compensation are attributable to the officers' participation in the Deferred and Incentive Compensation Plan of the Texas Utilities Company System (Plan). Under the Plan, officers of the Company with a title of Vice President or above may defer a percentage of their compensation not to exceed a maximum percentage determined by the Organization and Compensation Committee of the Board of Directors of Texas Utilities (Committee) for each Plan year and in any event not to exceed 15% of the participant's compensation. The Company makes a matching award equal to 150% of the deferred compensation. In addition, the Committee can establish incentive awards under the Plan. In no event will the sum of all incentive awards in any Plan year exceed 25% of the aggregate compensation of eligible employees. These matching and incentive awards are subject to forfeiture under certain circumstances. Under the Plan, a trustee purchases Texas Utilities common stock with an amount of cash equal to the deferred compensation, matching award and incentive award and the Company establishes accounts for each participant containing performance units equal to such number of common shares. Plan investments, including reinvested dividends, are restricted to Texas Utilities common stock. On the expiration of the applicable maturity period (three years for incentive awards, and five years for deferrals and matching awards) the value of the participants' accounts are paid in cash based upon the then current value of the units; provided, however, that in no event shall a participant's account be deemed to have a

cash value which is less than the sum of such participant's deferred amount together with a 6% per annum (compounded annually) interest equivalent thereon. The maturity requirement is waived if the participant dies or becomes totally and permanently disabled.

Compensation deferred under the Plan is included in amounts reported as Salary in the Summary Compensation Table. Amounts shown in the table below represent the number of shares purchased under the Plan with such deferred salaries for 1993:

Long-Term Incentive Plan - Awards in Last Fiscal Year

Name	Number of Shares, Units or Other Rights	Performance or Other Period Until Maturation or Payout
Erle Nye	1,502	5 years
Michael D. Spence	763	5 Years
T. L. Baker	627	5 Years
W. M. Taylor	590	5 Years
E. L. Watson	606	5 Years

Incentive and matching awards under the Plan are included under Restricted Stock Awards in the Summary Compensation Table. As a result of these awards and undistributed awards made under the Plan in prior years, at December 31, 1993 the number and market value of performance units (each of which is equal to one share of common stock) held in the Plan accounts for Messrs. Nye, Spence, Baker, Taylor and Watson were 15,336 ($663,282), 6,208 ($268,496), 4,910 ($212,358), 4,934 ($213,396) and 4,673 ($202,107).

Amounts reported as LTIP Payouts in the Summary Compensation Table represent payouts maturing during such years of earnings on salary deferred under the Plan in prior years.

(3) Amounts reported as All Other Compensation are attributable to the officers' participation in certain benefit plans hereinafter described. Pursuant to the transition rules promulgated by the Securities and Exchange Commission with respect to the disclosure of executive compensation, such amounts for 1991 are omitted.

Under the Employees' Thrift Plan of the Texas Utilities Company System, as amended effective January 1, 1993, all employees with at least six months of full time service with the Company may invest up to 16% of their regular salary or wages in common stock of Texas Utilities, or in a variety of selected mutual funds. The amounts reported under All Other Compensation in the Summary Compensation Table include contributions by employer-corporations to each participant's account of 40%, 50% or 60% of the employee's savings, up to 6% of the employee's regular salary or wages, depending upon length of service, which amount is invested in the common stock of Texas Utilities. During 1993, these employer contributions for Messrs. Nye, Spence, Baker, Taylor and Watson amounted to $8,490, $6,763, $2,334, $3,671 and $6,244, respectively.

Texas Utilities established a Salary Deferral Program (Program) effective April 1, 1991 under which each employee of the Company and its subsidiaries whose annual salary is $80,000 ($84,870 for the Program Year beginning April 1993) or more may elect to defer a percentage of annual salary for a period of seven years, a period ending with the retirement of such employee, or for a combination thereof. Such deferrals may not exceed in the aggregate 10% of such annual salary, provided that no more than 6% may be deferred under the retirement option for the period ending with the retirement of such employee. Deferred compensation is included in amounts reported under Salary in the Summary Compensation Table. The Company makes a matching award, subject to forfeiture under certain circumstances, equal to 100% of the deferred compensation. A trustee will distribute at the end of the applicable maturity period cash equal to the amounts deferred and matching awards plus earnings equal to the greater of the actual earnings of Program assets, or the average interest rate during the applicable maturity period of U.S. Treasury Notes with a maturity of ten years. The distribution of the amounts due under the Program will be in a lump sum if the maturity period is seven years or, if the retirement option is elected, in twenty annual installments. The Company is financing the retirement portion of the Program through the purchase of corporate owned life insurance on the lives of the participants and the proceeds from such insurance are expected to allow the Company to fully recover the cost of the retirement option. During 1993, matching awards, which are included under All Other Compensation in the Summary Compensation Table, were made for Messrs. Nye, Spence, Baker, Taylor and Watson in the amounts of $55,417, $27,483, $23,708, $17,625 and $22,700, respectively.

PENSION TABLE

The Company maintains a retirement plan qualified under applicable provisions of the Internal Revenue Code (Code). Annual retirement benefits are computed as follows: for each year of accredited service up to a total of 40 years of service, 1.3% of the first $7,800, plus 1.5% of the excess over $7,800 of average annual salary received by the participant during his three years of highest earnings. Retirement benefits are computed with respect to base salaries only and amounts reported under Salary for the named officers in the Summary Compensation Table herein approximate earnings as defined by the retirement plans. Such benefits are not subject to any reduction for Social Security payments. Benefits payable from a qualified retirement plan are limited by provisions of the Code and the Company maintains a Supplemental Retirement Plan which provides for the payment of retirement benefits calculated in accordance with the retirement plan formula which would otherwise be limited by the provisions of the Code. As of February 28, 1994, years of accredited service under the plans for Messrs. Nye, Spence, Baker, Taylor and Watson were 31, 27, 23, 25 and 34, respectively. The table illustrates the total annual benefit payable at retirement under these retirement plans.

3-year average annual earnings	20 Years Service	25 Years Service	30 Years Service	35 Years Service	40 Years Service
$ 50,000	$ 14,688	$ 18,360	$ 22,032	$ 25,704	$ 29,376
100,000	29,688	37,110	44,532	51,954	59,376
200,000	59,688	74,610	89,532	104,454	119,376
400,000	119,688	149,610	179,532	209,454	239,376
500,000	149,688	187,110	224,532	261,954	299,376
600,000	179,688	224,610	269,532	314,454	359,376
800,000	239,688	299,610	359,532	419,454	479,376
900,000	269,688	337,110	404,532	471,954	539,376

The following report is presented herein for informational purposes only. This information is not required to be included herein and shall not be deemed to form a part of this report or be "filed" with the Securities and Exchange Commission. The report set forth hereinafter is the report of the Organization and Compensation Committee of the Board of Directors of Texas Utilities. While this report deals with compensation of executives of Texas Utilities, it is illustrative of the methodology utilized in establishing the compensation of executive officers of the Company. References in the report to the Company are references to Texas Utilities and references to pages of the proxy statement are references to the Texas Utilities' proxy statement to be filed with the Securities and Exchange Commission on or about April 1, 1994.

ORGANIZATION AND COMPENSATION COMMITTEE REPORT ON EXECUTIVE COMPENSATION

The Organization and Compensation Committee of the Board of Directors is responsible under the Company's Bylaws for establishing the level of compensation of the executive officers of the Company. The Committee consists of all of the nonemployee directors of the Company and is chaired by James A. Middleton. The Committee has directed the preparation of this report and has approved its contents and its submission to the shareholders.

The Committee normally considers executive compensation matters at its May meeting held in connection with the Annual Meeting of Shareholders. At that meeting, the Committee reviews and recommends to the full Board the amounts of executive officers' base salaries and bonuses, if any, and establishes the maximum deferral percentage and incentive awards, if any, under the Deferred and Incentive Compensation Plan (Plan) which is described on pages 8, 9 and 10 of this proxy statement. Although Company management may be present during Committee discussions of officers' compensation, Committee decisions with respect to the compensation of the Chairman of the Board and Chief Executive and the President are reached in private session without the presence of any member of Company management.

Levels of executive compensation, in the option of the Committee, should be based upon an evaluation of the performance of the Company and its officers generally and in comparison to persons with comparable responsibilities in similar business enterprises. Compensation plans should align executive compensation with returns to shareholders with due consideration accorded to balancing both long-term and short-term objectives. Such compensation principles and practices have allowed, and should continue to allow, the Company to attract, retain and motivate its key executives.

In establishing levels of executive compensation, the Committee regularly reviews Company performance data and its officers' compensation compared to the performance of companies in similar businesses and the compensation levels of the management of such companies, including companies generally comparable in size represented in the Moody's 24 Utilities whose comparative investment return is depicted in the graph on page 15. Information is gathered from industry sources and other published and private materials which provides a basis for comparing the largest electric and gas utilities and other survey groups representing a large variety of business organizations. Included in the data was that, in 1992, TU Electric, the Company's principal subsidiary, was the largest electric utility in the United States as measured by megawatt hour sales; and compared to other electric utilities in the United States it was 5th in electric revenues, 3rd in total assets, 2nd in net generating capability, 6th in number of customers and 15th in number of employees. The Committee also reviews a variety of industry financial and operating performance comparisons (including productivity indicators, service reliability indexes and measures of efficiency and service quality) throughout the year and at the time salaries are established in May of each year. These industry comparisons constitute an important component of the Committee's review of executive compensation. The Committee's decisions, however, are subjective because it has not adopted or approved a specific formula or other criteria linking any target level or performance measure, or the aggregate of all measures, to the levels of executive compensation.

The compensation of the officers of the Company consists primarily of base salaries, cash bonuses and the opportunity to participate in the Plan. Benefits provided under the Plan represent a substantial portion of the officers' compensation and the value of the future payment thereof is directly related to the future performance of the Company's common stock. The named executive officers participate to the fullest extent permissible in the elective feature of the Plan. The officers are also eligible to participate in the Salary Deferral Program and the Employees' Thrift Plan, both of which are described on pages 10 and 11 of this proxy statement. The officers also participate in the retirement plan, the benefits payable under which are described on page 11 of this proxy statement. Except for benefits under these plans, the officers do not receive any other form of direct or indirect compensation from the Company.

At its meeting held in May 1993, the Committee established the Chief Executive's salary at an annual rate of $775,000 representing a $75,000, or eleven percent, increase over the annual rate established in May 1992. Also, the Committee provided for a cash bonus to the Chief Executive of $125,000 and an incentive award under the Plan of $125,000. This amount of compensation was established based upon the Committee's subjective evaluation of the information described herein. In addition to the Committee's evaluation of such comparative performance and compensation information, specific accomplishments considered by the Committee in establishing the compensation, specifically the salary increase, bonus and incentive award of the Chief Executive, included the progress made in the redirection of the Company's business through its Competitive Action Plan which was implemented to reduce costs on a System-wide basis, and the receipt of an operating license for Unit 2 of the Comanche Peak nuclear generating station. The Committee also recognized that the base salary of the Chief Executive was not increased in 1992, nor was a bonus awarded.

Section 162(m) of the Internal Revenue Code, which was enacted as a part of the Omnibus Budget Reconciliation Act of 1993, limits, effective January 1, 1994, the amount of compensation which a publicly traded corporation can deduct for federal income tax purposes. Various exceptions to the limitation are provided. These exceptions relate generally to types of compensation plans and programs which the Company does not maintain. Nevertheless, the Company does not expect to provide compensation in 1994 which would not be deductible for federal income tax purposes. The Company expects to continue to maintain a competitive compensation program in future years, and it is not possible to predict the impact which Section 162(m) may have on such future compensation or the deductibility thereof.

Shareholder comments to the Committee are welcomed and should be addressed to the Corporate Secretary of the Company at the Company's offices.

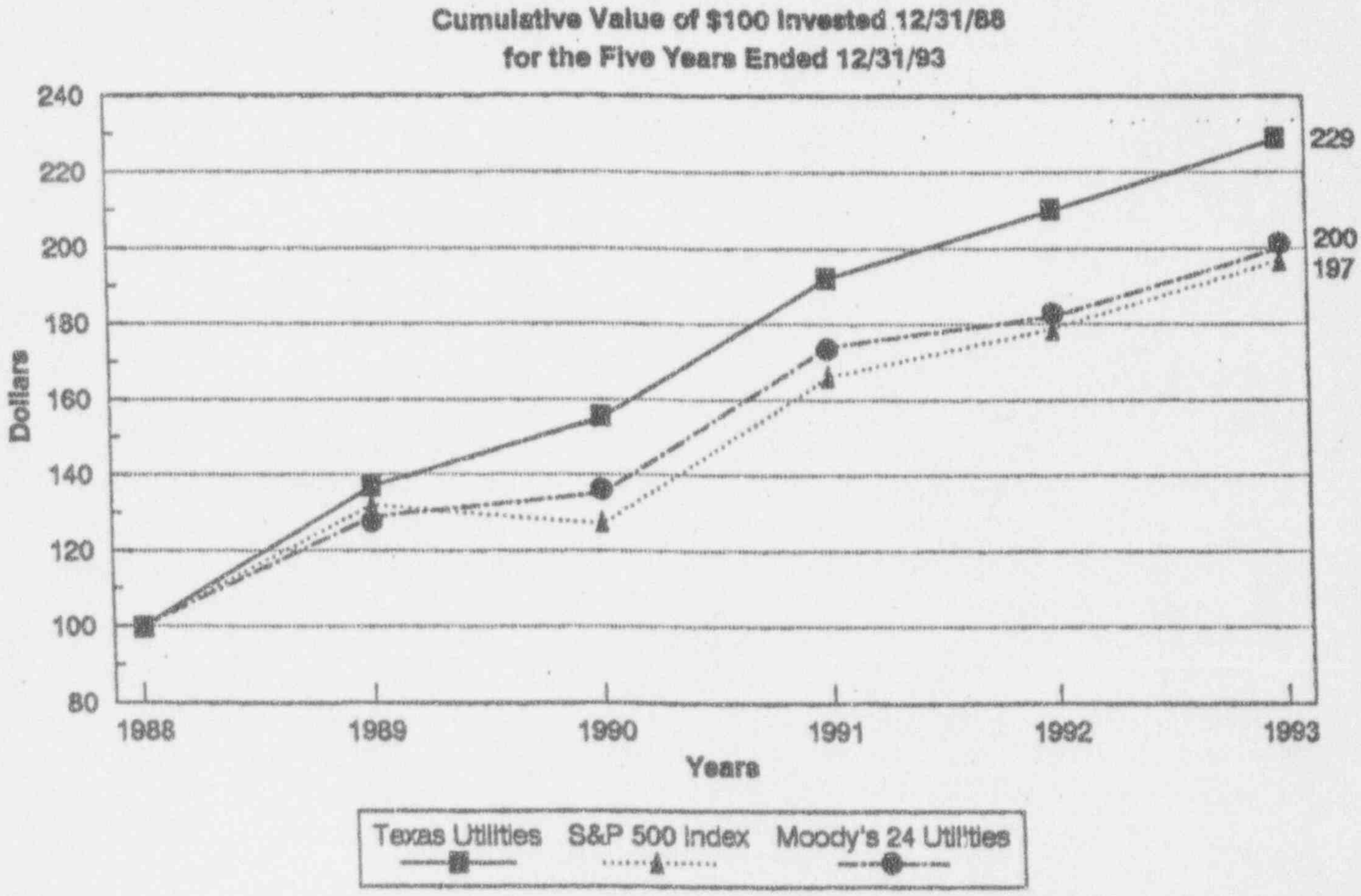
ORGANIZATION AND COMPENSATION COMMITTEE

James A. Middleton, Chair
Jack W. Evans
Bayard H. Friedman
William M. Griffin
Kerney Laday
Margaret N. Maxey
Charles R. Perry
Herbert H. Richardson

PERFORMANCE GRAPH

The following graph is presented herein for informational purposes only. This information is not required to be included herein and shall not be deemed to form a part of this report or be "filed" with the Securities and Exchange Commission. The graph pertains to the common stock of Texas Utilities. Inasmuch as the common stock of the Company is wholly owned by Texas Utilities, this information is the most relevant data which is available in regard to this subject matter.

The following graph compares the performance of the Company's common stock to the S&P 500 Index and to the Moody's 24 Utilities for the last five years. The graph assumes the investment of $100 at December 31, 1988 and that all dividends were reinvested. The amount of the investment at the end of each year is shown in the graph and in the table which follows.



	1988	1989	1990	1991	1992	1993
Texas Utilities	100	137	155	192	210	229
S&P 500 Index	100	132	127	166	179	197
Moody's 24 Utilities	100	129	135	174	182	200

Item 12. SECURIT'. OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT.

Security ownership of certain beneficial owners at February 28, 1994:

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common Stock, without par value, of the Company	Texas Utilities Company 2001 Bryan Tower Dallas, Texas 75201	152,000,000 shares sole voting and investment power	100.0%

Security ownership of management at February 28, 1994:

The following lists the common stock of Texas Utilities owned by the Directors and Executive Officers of the Company. The named individuals have sole voting and investment power for the shares of common stock reported. Ownership of such common stock constituted less than 1% of the outstanding shares for each individual. None of the named individuals own ~ny of the preferred stock of the Company.

Name	Number of Shares of Common Stock
T. L. Baker	2,102
J. S. Farrington	15,972
H. Jarrell Gibbs	4,239
Erle Nye	14,716
Michael D. Spence	5,898
W. M. Taylor	6,246
E. L. Watson	5,136
All Directors and Executive Officers as a group (7)	54,309

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.

None.

PART IV

Item 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K.

The following financial statement schedules are omitted because of the absence of the conditions under which they are required or because the required information is included in the Financial Statements or notes thereto: I, II, III, IV, VII, XI, XII and XIII.

(b) Reports on Form 8-K:

Reports on Form 8-K filed since September 30, 1993, are as follows:

Date of Report	Items Reported
October 12, 1993	Item 7. FINANCIAL STATEMENTS AND EXHIBITS
October 26, 1993	Item 5. OTHER EVENTS
November 24, 1993	Item 5. OTHER EVENTS
January 14, 1994	Item 5. OTHER EVENTS
January 31, 1994	Item 5. OTHER EVENTS

(c) Exhibits:

	Previously Filed*			
Exhibits	With File Number	As Exhibit		Number Dated
3(a)			—	Restated Articles of Incorporation of the Company.
3(b)	33-64694	4(c)	—	Bylaws of the Company, as amended.
4(a)	2-90185	4(a)	—	Mortgage and Deed of Trust, dated as of December 1, 1983, between the Company and Irving Trust

Item 14. **EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K (Continued).**

Exhibits	Previously Filed* With File Number	Previously Filed* As Exhibit		Number	Dated
				Company (now The Bank of New York), Trustee.	
4(a)-1			—	Supplemental Indentures to Mortgage and Deed of Trust:	
	2-90185	4(b)		First	April 1, 1984
	2-92738	4(a)-1		Second	September 1, 1984
	2-97185	4(a)-1		Third	April 1, 1985
	2-99940	4(a)-1		Fourth	August 1, 1985
	2-99940	4(a)-2		Fifth	September 1, 1985
	33-01774	4(a)-2		Sixth	December 1, 1985
	33-9583	4(a)-1		Seventh	March 1, 1986
	33-9583	4(a)-2		Eighth	May 1, 1986
	33-11376	4(a)-1		Ninth	October 1, 1986
	33-11376	4(a)-2		Tenth	December 1, 1986
	33-11376	4(a)-3		Eleventh	December 1, 1986
	33-14584	4(a)-1		Twelfth	February 1, 1987
	33-14584	4(a)-2		Thirteenth	March 1, 1987
	33-14584	4(a)-3		Fourteenth	April 1, 1987
	33-24089	4(a)-1		Fifteenth	July 1, 1987
	33-24089	4(a)-2		Sixteenth	September 1, 1987
	33-24089	4(a)-3		Seventeenth	October 1, 1987
	33-24089	4(a)-4		Eighteenth	March 1, 1988
	33-24089	4(a)-5		Nineteenth	May 1, 1988
	33-30141	4(a)-1		Twentieth	September 1, 1988
	33-30141	4(a)-2		Twenty-first	November 1, 1988
	33-30141	4(a)-3		Twenty-second	January 1, 1989
	33-35614	4(a)-1		Twenty-third	August 1, 1989
	33-35614	4(a)-2		Twenty-fourth	November 1, 1989
	33-35614	4(a)-3		Twenty-fifth	December 1, 1989
	33-35614	4(a)-4		Twenty-six	February 1, 1990
	33-39493	4(a)-1		Twenty-seventh	September 1, 1990
	33-39493	4(a)-2		Twenty-eighth	October 1, 1990
	33-39493	4(a)-3		Twenty-ninth	October 1, 1990
	33-39493	4(a)-4		Thirtieth	March 1, 1991
	33-45104	4(a)-1		Thirty-first	May 1, 1991
	33-45104	4(a)-2		Thirty-second	July 1, 1991
	33-46293	4(a)-1		Thirty-third	February 1, 1992
	33-49710	4(a)-1		Thirty-fourth	April 1, 1992
	33-49710	4(a)-2		Thirty-fifth	April 1, 1992
	33-49710	4(a)-3		Thirty-sixth	June 1, 1992
	33-49710	4(a)-4		Thirty-seventh	June 1, 1992
	33-57576	4(a)-1		Thirty-eighth	August 1, 1992
	33-57576	4(a)-2		Thirty-ninth	October 1, 1992
	33-57576	4(a)-3		Fortieth	November 1, 1992
	33-57576	4(a)-4		Forty-first	December 1, 1992

Item 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K (Continued).

Exhibits	Previously Filed* With File Number	As Exhibit		Number	Dated
	33-60528	4(a)-1		Forty-second	March 1, 1993
	33-64692	4(a)-1		Forty-third	April 1, 1993
	33-64692	4(a)-2		Forty-fourth	April 1, 1993
	33-64692	4(a)-3		Forty-fifth	May 1, 1993
	33-68100	4(a)-1		Forty-sixth	July 1, 1993
	0-11442 Form 10-Q (Quarter Ended September 30,1993)	99(b)		Forty-seventh	October 1, 1993
4(a)-2				Forty-eighth	November 1, 1993
4(b)	2-2801	B-2	—	Mortgage and Deed of Trust, dated as of February 1, 1937, between Dallas Power & Light Company and Old Colony Trust Company, Trustee (The First National Bank of Boston, successor Trustee).	
4(b)-1			—	Supplemental Indentures to Mortgage and Deed of Trust:	
	2-7855	7(a)		First	April 1, 1949
	2-8466	7(a)-2		Second	June 1, 1950
	2-10071	4(b)-3		Third	March 1, 1953
	2-12200	2(b)-1		Fourth	February 1, 1956
	2-77857	4(b)-5		Fifth	December 1, 1956
	2-77857	4(b)-6		Sixth	December 1, 1959
	2-20997	2(b)-7		Seventh	February 1, 1963
	2-77857	4(b)-8		Eighth	January 1, 1966
	2-25805	2(b)-9		Ninth	February 1, 1967
	2-37161	2(c)		Tenth	June 1, 1970
	2-42043	2(c)		Eleventh	November 1, 1971
	2-45403	2(c)		Twelfth	September 1, 1972
	2-52708	2(c)		Thirteenth	March 1, 1975
	2-77857	4(b)-14		Fourteenth	May 1, 1977
	2-71621	4(c)		Fifteenth	June 1, 1981
	2-77857	4(b)-16		Sixteenth	November 1, 1981
	2-77857	4(c)		Seventeenth	July 1, 1982
	2-81476	4(b)-18		Eighteenth	November 1, 1982
	2-81476	4(c)		Nineteenth	February 1, 1983
	2-90185	4(c)-1		Twentieth	June 1, 1983
	2-90185	4(c)-2		Twenty-first	January 1, 1984
	2-90185	4(c)-3		Twenty-second	April 1, 1984
	2-92738	4(b)-1		Twenty-third	September 1, 1984
	2-99940	4(b)-1		Twenty-fourth	September 1, 1985
	33-11376	4(b)-1		Twenty-fifth	October 1, 1986
	33-14584	4(b)-1		Twenty-sixth	March 1, 1987
	33-24089	4(b)-1		Twenty-seventh	July 1, 1987
	33-30141	4(b)-1		Twenty-eighth	January 1, 1989

Item 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K (Continued).

Exhibits	Previously Filed* With File Number	As Exhibit		Number	Dated
	33-35614	4(b)-1		Twenty-ninth	November 1, 1989
	33-46293	4(b)-2		Thirtieth	February 1, 1992
	33-49710	4(b)-1		Thirty-first	June 1, 1992
4(c)	2-5609	7(b)	—	Mortgage and Deed of Trust, dated as of March 1, 1945, between Texas Electric Service Company and The Fort Worth National Bank, Trustee (Bank One, Texas, N.A., successor Trustee).	
4(c)-1			—	Supplemental Indentures to Mortgage and Deed of Trust:	
	2-7186	7(b)		First	October 1, 1947
	2-7423	7(c)		Second	April 1, 1948
	2-7894	7(d)		Third	April 1, 1949
	2-8982	7(e)		Fourth	June 1, 1951
	2-9547	4(c)		Fifth	May 1, 1952
	2-10118	4(c)		Sixth	April 1, 1953
	2-12227	2(c)		Seventh	March 1, 1955
	2-60449	2(b)-1		Eighth	March 1, 1956
	2-60449	2(b)-1		Ninth	July 1, 1957
	2-60449	2(b)-1		Tenth	November 1, 1958
	2-21105	2(b)		Eleventh	April 1, 1963
	2-23056	2(b)		Twelfth	February 1, 1965
	2-24384	2(c)		Thirteenth	February 1, 1966
	2-26297	2(c)		Fourteenth	May 1, 1967
	2-31474	2(c)		Fifteenth	March 1, 1969
	2-38358	2(c)		Sixteenth	October 1, 1970
	2-39627	2(c)		Seventeenth	April 1, 1971
	2-42552	2(c)		Eighteenth	January 1, 1972
	2-60449	2(b)-1		Nineteenth	April 1, 1974
	2-60449	2(b)-1		Twentieth	December 1, 1974
	2-60449	2(b)-1		Twenty-first	June 1, 1975
	2-60449	2(b)-1		Twenty-second	March 1, 1976
	2-63425	2(c)		Twenty-third	February 1, 1979
	2-66633	2(c)		Twenty-fourth	March 1, 1980
	2-74809	4(c)-1		Twenty-fifth	November 1, 1981
	2-74809	4(d)-1		Twenty-sixth	December 1, 1981
	2-76675	4(c)		Twenty-seventh	April 1, 1982
	2-80329	4(c)		Twenty-eighth	November 1, 1982
	2-80329	4(d)		Twenty-ninth	December 1, 1982
	2-90185	4(d)-1		Thirtieth	June 1, 1983
	2-90185	4(d)-2		Thirty-first	January 1, 1984
	2-90185	4(d)-3		Thirty-second	April 1, 1984
	2-92738	4(c)-1		Thirty-third	September 1, 1984
	2-99940	4(c)-1		Thirty-fourth	August 1, 1985
	33-9583	4(c)-1		Thirty-fifth	March 1, 1986

Item 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K (Continued).

	Previously Filed*			
Exhibits	With File Number	As Exhibit	Number	Dated
	33-11376	4(c)-1	Thirty-sixth	December 1, 1986
	33-14584	4(c)-1	Thirty-seventh	February 1, 1987
	33-24089	4(c)-1	Thirty-eighth	September 1, 1987
	33-24089	4(c)-2	Thirty-ninth	October 1, 1987
	33-24089	4(c)-3	Fortieth	March 1, 1988
	33-30141	4(c)-1	Forty-first	September 1, 1988
	33-39493	4(c)-1	Forty second	September 1, 1990
	33-39493	4(c)-2	Forty-third	March 1, 1991
	33-46293	4(c)-2	Forty-fourth	February 1, 1992
	33-57576	4(c)-1	Forty-fifth	October 1, 1992
	33-57576	4(c)-2	Forty-sixth	November 1, 1992
	33-60528	4(c)-1	Forty-seventh	March 1, 1993
	33-68100	4(c)-1	Forty-eighth	July 1, 1993
	0-11442 Form 10-Q (Quarter ended September 30, 1993)	99(a)	Forty-ninth	October 1, 1993
4(d)	2-5718	7(c)	— Mortgage and Deed of Trust, dated as of May 1, 1945, between Texas Power & Light Company and Republic National Bank of Dallas, Trustee (NationsBank of Texas, N.A., successor Trustee).	
4(d)-1			— Supplemental Indentures to Mortgage and Deed of Trust:	
	2-7204	7(a)	First	October 1, 1947
	2-7446	7(a)	Second	April 1, 1948
	2-9474	4(c)	Third	April 1, 1952
	2-10204	4(c)	Fourth	May 1, 1953
	2-11162	2(b)	Fifth	October 1, 1954
	2-12856	4(c)	Sixth	November 1, 1956
	2-14553	2(b)	Seventh	December 1, 1958
	2-19452	2(b)-1	Eighth	January 1, 1961
	2-21028	2(b)	Ninth	February 1, 1963
	2-24326	2(c)	Tenth	January 1, 1965
	2-24326	2(d)	Eleventh	February 1, 1966
	2-25885	2(c)	Twelfth	February 1, 1967
	2-27853	2(c)	Thirteenth	January 1, 1968
	2-35941	2(c)	Fourteenth	February 1, 1970
	2-38171	2(c)	Fifteenth	September 1, 1970
	2-39083	2(c)	Sixteenth	February 1, 1971
	2-42763	2(c)	Seventeenth	February 1, 1972
	2-46740	2(c)	Eighteenth	February 1, 1973
	2-73790	4(b)-19	Nineteenth	February 1, 1974
	2-73790	4(b)-20	Twentieth	October 1, 1974
	2-52865	2(c)	Twenty-first	April 1, 1975

Item 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K (Continued).

	Previously Filed*			
Exhibits	With File Number	As Exhibit	Number	Dated
	2-55210	2(c)	Twenty-second	January 1, 1976
	2-57963	2(c)	Twenty-third	February 1, 1977
	2-63369	2(c)	Twenty-fourth	February 1, 1979
	2-67594	(b)(2)-2	Twenty-fifth	May 1, 1980
	2-73790	4(c)	Twenty-sixth	September 1, 1981
	2-77733	4(b)	Twenty-seventh	November 1, 1981
	2-77733	4(c)	Twenty-eighth	June 1, 1982
	2-90185	4(e)-1	Twenty-ninth	November 1, 1982
	2-90185	4(e)-2	Thirtieth	June 1, 1983
	2-90185	4(e)-3	Thirty-first	October 1, 1983
	2-90185	4(e)-4	Thirty-second	January 1, 1984
	2-90185	4(e)-5	Thirty-third	April 1, 1984
	2-92738	4(d)-1	Thirty-fourth	September 1, 1984
	2-97185	4(d)-1	Thirty-fifth	April 1, 1985
	33-01774	4(d)-1	Thirty-sixth	December 1, 1985
	33-9583	4(d)-1	Thirty-seventh	May 1, 1986
	33-11376	4(d)-1	Thirty-eighth	December 1, 1986
	33-14584	4(d)-1	Thirty-ninth	April 1, 1987
	33-24089	4(d)-1	Fortieth	May 1, 1988
	33-30141	4(d)-1	Forty-first	August 1, 1988
	33-35614	4(d)-1	Forty-second	August 1, 1989
	33-35614	4(d)-2	Forty-third	December 1, 1989
	33-35614	4(d)-3	Forty-fourth	February 1, 1990
	33-39493	4(d)-1	Forty-fifth	October 1, 1990
	33-45104	4(d)-1	Forty-sixth	May 1, 1991
	33-45104	4(d)-2	Forty-seventh	July 1, 1991
	33-46293	4(d)-2	Forty-eighth	February 1, 1992
	33-49710	4(d)-1	Forty-ninth	April 1, 1992
	33-57576	4(d)-1	Fiftieth	August 1, 1992
	33-57576	4(d)-2	Fifty-first	December 1, 1992
	33-64692	4(d)-1	Fifty-second	April 1, 1993
	33-64692	4(d)-2	Fifty-third	May 1, 1993
4(d)-2			Fifty-fourth	November 1, 1993
4(e)			— Agreement to furnish certain debt instruments.	
4(f)	33-68104	4(b)-16	— Deposit Agreement between the Company and Chemical Bank, dated as of January 11, 1993.	
4(g)	33-68104	4(b)-17	— Deposit Agreement between the Company and Chemical Bank, dated as of August 4, 1993.	
4(h)			— Deposit Agreement between the Company and Chemical Bank, dated as of October 14, 1993.	
10(a) **	0-11442 Form 10-K (1992)	10(a)	— Deferred and Incentive Compensation Plan of the Texas Utilities Company System, as amended June 30, 1992.	

Item 14. EXHI[illegible]NANCIAL STATEMENT SCHEDULES AND REPORTS ON FCRM 8-K (Continued).

Exhibits	Previously Filed* With File Number	As Exhibit		Number Dated
10(b) **	0-11442 Form 10-K (1992)	10(b)	—	Salary Deferral Program of the Texas Utilities Company System, as amended May 31, 1992.
10(c) **	0-11442 Form 10-K (1992)	10(c)	—	Restated Supplemental Retirement Plan for the employees of Texas Utilities Company System, dated as of January 1, 1991.
12			—	Computation of Ratio of Earnings to Fixed Charges.
23(a)			—	Co:sent of Counsel.
23(b)			—	Independent Auditors' Consent.
99(a)			—	Agreement, dated as of February 12, 1988, between TU Electric and Texas Municipal Power Agency.
99(b)	33-55408	99(a)	—	Agreement, dated as of July 5, 1988, between the Company and the Brazos Electric Power Cooperative, Inc.
99(c)	33-55408	99(b)	—	Agreement, dated as of February 1, 1990, between TU Electric and Tex-La Electric Cooperative, Inc.
99(d)	33-55408	99(c)	—	Amended and Restated Credit Agreement, dated as of April 1, 1990, among the Company, Texas Utilities, certain banks and Morgan Guaranty Trust Company of New York, Agent.
99(e)	33-23532	4(c)(i)	—	Trust Indenture, Security Agreement and Mortgage, dated as of December 1, 1987, as supplemented by Supplement No. 1 thereto dated as of May 1, 1988 among the Lessor, TU Electric and the Trustee.
99(f)	33-24089	4(e)	—	Supplement No. 2 to Trust Indenture, Security Agreement and Mortgage, dated as of August 1, 1988.
99(g)	33-24089	4(e)-1	—	Supplement No. 3 to Trust Indenture, Security Agreement and Mortgage, dated as of August 1, 1988.
99(h)	0-11442 Form 10-Q (Quarter ended June 30, 1993)	99(c)	—	Supplement No. 4 to Trust Indenture, Security Agreement and Mortgage, dated as of July 1, 1993.
99(i)	33-23532	4(d)	—	Lease Agreement, dated as of December 1, 1987 between the Lessor and TU Electric as supplemented by Supplement No. 1 thereto dated as of May 20, 1988 between the Lessor and TU Electric.
99(j)	33-24089	4(f)	—	Lease Agreement Supplement No. 2, dated as of August 18, 1988.

Item 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K (Concluded).

	Previously Filed*			
Exhibits	With File Number	As Exhibit		Number Dated
99(k)	33-24089	4(f)-1	—	Lease Agreement Supplement No. 3, dated as of August 25, 1988.
99(l)	33-63434	4(d)(iv)	—	Lease Agreement Supplement No. 4, dated as of December 1, 1988.
99(m)	33-63434	4(d)(v)	—	Lease Agreement Supplement No. 5, dated as of June 1, 1989.
99(n)	0-11442 Form 10-Q (Quarter ended June 30, 1993)	99(d)	—	Lease Agreement Supplement No. 6, dated as of July 1, 1993.
99(o)	33-23532	4(e)	—	Participation Agreement dated as of December 1, 1987, as amended by a Consent to Amendment of the Participation Agreement, dated as of May 20, 1988, each among the Lessor, the Trustee, the Owner Participant, certain banking institutions, Capcorp, Inc. and TU Electric.
99(p)	33-24089	4(g)	—	Consent to Amendment of the Participation Agreement, dated as of August 18, 1988.
99(q)	33-24089	4(g)-1	—	Supplement No. 1 to the Participation Agreement, dated as of August 18, 1988.
99(r)	33-24089	4(g)-2	—	Supplement No. 2 to the Participation Agreement, dated as of August 18, 1988.
99(s)	33-63434	4(e)(v)	—	Supplement No. 3 to the Participation Agreement, dated as of December 1, 1988.
99(t)	0-11442 Form 10-Q (Quarter ended June 30, 1993)	99(e)	—	Supplement No. 4 to the Participation Agreement, dated as of June 17, 1993.

*Incorporated herein by reference.

**Management contract or compensation plan or arrangement required to be filed as an exhibit to this report pursuant to Item 14(c) of Form 10-K.

TEXAS UTILITIES ELECTRIC COMPANY

SCHEDULE V — ELECTRIC PLANT

For Each of the Three Years in the Period Ended December 31, 1993

COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E	COLUMN F
Classification	Balance at Beginning of Year	Additions at Cost	Retirements	Other Changes — Add	Balance at End of Year
			Thousands of Dollars		
Year Ended December 31, 1993					
Electric plant					
In service:					
Production	$10,490,215	$5,020,295	$ 9,126	$ —	$15,501,384
Transmission	1,493,601	46,754	2,908	—	1,537,447
Distribution	3,567,646	234,197	28,484	—	3,773,359
General	440,665	19,687	11,257	—	449,095
Total	15,992,127	5,320,933	51,775	—	21,261,285
Construction work in progress	5,528,222	(4,583,757)	—	—	944,465
Nuclear fuel — net	358,087	28,063	—	(65,259)(a)	320,891
Held for future use	29,639	9,363	—	—	39,002
Electric plant before reserve	21,908,075	774,602	51,775	(65,259)	22,565,643
Less reserve for regulatory disallowances	(1,308,460)	—	—	—	(1,308,460)
Total electric plant	$20,599,615	$ 774,602	$51,775	$ (65,259)	$21,257,183
Year Ended December 31, 1992					
Electric plant					
In service:					
Production	$10,421,387	$ 80,882	$12,054	$ —	$10,490,215
Transmission	1,443,565	55,073	5,037	—	1,493,601
Distribution	3,377,396	218,007	27,757	—	3,567,646
General	425,448	24,194	8,977	—	440,665
Total	15,667,796	378,156	53,825	—	15,992,127
Construction work in progress	4,809,088	719,134	—	—	5,528,222
Nuclear fuel — net	333,701	48,600	—	(24,214)(a)	358,087
Held for future use	29,069	570	—	—	29,639
Electric plant before reserve	20,839,654	1,146,460	53,825	(24,214)	21,908,075
Less reserve for regulatory disallowances	(1,308,460)	—	—	—	(1,308,460)
Total electric plant	$19,531,194	$1,146,460	$53,825	$ (24,214)	$20,599,615
Year Ended December 31, 1991					
Electric plant					
In service:					
Production	$10,342,116	$ 90,446	$11,175	$ —	$10,421,387
Transmission	1,388,959	57,829	3,223	—	1,443,565
Distribution	3,190,258	220,796	33,658	—	3,377,396
General	408,294	26,419	9,265	—	425,448
Total	15,329,627	395,490	57,321	—	15,667,796
Construction work in progress	4,012,241	796,847	—	—	4,809,088
Nuclear fuel — net	311,416	47,678	—	(25,393)(a)	333,701
Held for future use	28,989	80	—	—	29,069
Electric plant before reserve	19,682,273	1,240,095	57,321	(25,393)	20,839,654
Less reserve for regulatory disallowances	—	—	—	(1,308,460)(b)	(1,308,460)
Total electric plant	$19,682,273	$1,240,095	$57,321	$(1,333,853)	$19,531,194

(a) Other changes to nuclear fuel includes $65,259,000, $24,214,000 and $25,393,000 deducted for amortization in 1993, 1992 and 1991, respectively.

(b) Disallowed Comanche Peak related costs. (See Note 11 to Financial Statements.)

TEXAS UTILITIES ELECTRIC COMPANY

SCHEDULE VI — ACCUMULATED DEPRECIATION

For Each of the Three Years in the Period Ended December 31, 1993

COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E	COLUMN F
Classification	Balance at Beginning of Year	Additions Charged to Costs and Expenses (a)	Net Retirements	Other Changes — Add (b)	Balance at End of Year
			Thousands of Dollars		
Year Ended December 31, 1993					
Accumulated depreciation	$3,741,020	$427,294	$54,706	$5,247	$4,118,855
Year Ended December 31, 1992					
Accumulated depreciation	$3,392,463	$406,088	$63,444	$5,913	$3,741,020
Year Ended December 31, 1991					
Accumulated depreciation	$3,026,995	$418,899	$60,582	$7,151	$3,392,463

(a) Includes depreciation on lignite fuel production facilities charged to fuel and decommissioning expense for Comanche Peak.
(b) Depreciation and depletion charged to various accounts, including depreciation of transportation and work equipment, based on estimated lives thereof, are charged to clearing accounts and allocated on the basis of the use of such equipment.

TEXAS UTILITIES ELECTRIC COMPANY

SCHEDULE VIII — VALUATION AND QUALIFYING ACCOUNTS

For Each of the Three Years in the Period Ended December 31, 1993

COLUMN A	COLUMN B	COLUMN C		COLUMN D	COLUMN E
		Additions			
Classification	Balance at Beginning of Year	Charged to Costs and Expenses	Charged to Other Accounts	Deductions (a)	Balance at End of Year
		Thousands of Dollars			
Valuation account, deducted from related asset on the balance sheet —					
Year Ended December 31, 1993					
Reserve for regulatory disallowances	$1,381,145	$ —	$ —	$ —	$1,381,145
Allowance for uncollectible accounts	1,613	21,430	—	16,739	6,304
Year Ended December 31, 1992					
Reserve for regulatory disallowances	$1,381,145	$ —	$ —	$ —	$1,381,145
Allowance for uncollectible accounts	2,931	4,102	—	5,420	1,613
Year Ended December 31, 1991					
Reserve for regulatory disallowances	$ —	$1,381,145	$ —	$ —	$1,381,145
Allowance for uncollectible accounts	2,290	14,226	—	13,585	2,931

(a) Deductions represents uncollectible accounts written off net of recoveries of amounts previously written off.

TEXAS UTILITIES ELECTRIC COMPANY

SCHEDULE IX — SHORT-TERM BORROWINGS

For Each of the Three Years in the Period Ended December 31, 1993

COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E	COLUMN F
Category of Aggregate Short-term Borrowings	**Balance At End of Year**	**Weighted Average Interest Rate**	**Maximum Amount Outstanding During Year**	**Weighted Average Amount Outstanding During Year (a)**	**Weighted Average Interest Rate During Year (a)**
			Thousands of Dollars		
Year Ended December 31, 1993					
Amounts payable to banks for borrowings ..	$ —	—	$300,000	$ 55,611	3.92%
Holders of commercial paper	—	—	299,700	54,401	3.72
Year Ended December 31, 1992					
Amounts payable to banks for borrowings ..	$250,000	3.86%	$350,000	$277,306	4.28%
Holders of commercial paper	—	—	139,857	8,069	3.79
Year Ended December 31, 1991					
Amounts payable to banks for borrowings ..	$250,000	5.77%	$300,000	$229,681	6.51%
Holders of commercial paper	—	—	133,800	35,756	6.84

(a) Weighted averages are based upon daily amounts outstanding and equivalent annual interest thereon.

TEXAS UTILITIES ELECTRIC COMPANY

SCHEDULE X — SUPPLEMENTARY INFORMATION

For Each of the Three Years in the Period Ended December 31, 1993

COLUMN A	COLUMN B		
	Charged to Expenses and Other Accounts		
	Year Ended December 31,		
Item	1993	1992	1991
	Thousands of Dollars		
Taxes other than income:			
Ad valorem	$210,849	$189,411	$176,414
Local gross receipts	154,731	126,849	122,683
State gross receipts	77,547	72,345	71,512
State franchise	(7,259)	20,252	49,182
Social security and unemployment	28,318	41,356	38,170
Public Utility Commission assessment	8,438	7,613	7,664
Miscellaneous	25,177	22,143	18,821
Total	$497,801	$479,969	$484,446
Charged to:			
Operating expenses	$445,220	$423,505	$437,347
Electric plant and sundry accounts	52,581	56,464	47,099

Maintenance and repairs, depletion, amortization, royalties, research and development, and advertising, other than amounts set out separately in the financial statements, are not material.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

TEXAS UTILITIES ELECTRIC COMPANY

Date: March 24, 1994

By: /s/ ERLE NYE
(Erle Nye, Chairman of the Board and Chief Executive)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

Signature	Title	Date
/s/ ERLE NYE (Erle Nye, Chairman of the Board and Chief Executive)	Principal Executive Officer and Director	March 24, 1994
/s/ H. JARRELL GIBBS (H. Jarrell Gibbs, Executive Vice President)	Principal Financial Officer and Director	
/s/ H. DAN FARELL (H. Dan Farell, Vice President and Controller)	Principal Accounting Officer	
/s/ T. L. BAKER (T. L. Baker)	Director	
/s/ J. S. FARRINGTON (J.S. Farrington)	Director	
/s/ MICHAEL D. SPENCE (Michael D. Spence)	Director	
/s/ W. M. TAYLOR (W. M. Taylor)	Director	
/s/ E. L. WATSON (E. L. Watson)	Director	