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William J. Cahill, Jr.
Group Vice President

April 1, 1993

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. J. L. Milhoan, Region IV, w/o enclosures
Resident Inspectors, CPSES, w/o enclosures

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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, 1992

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 1/4 of a share of $8.20 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 January 29, 1993 held by non-affiliates: None

Common Stock outstanding at January 29, 1993: 148,600,000 shares, without par value

DOCUMENTS INCORPORATED BY REFERENCE
None

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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). Texas Utilities also has three other subsidiaries which perform specialized services for the Texas Utilities Company System (System Companies), including the Company: 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.

The Company's service area covers the north central, eastern and western parts of Texas, with a population estimated at 5,590,000 — 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, Alliance Airport and the site of the Superconducting Super Collider. For energy sales and operating revenues contributed by each customer classification, see Item 6, Selected Financial Data — Operating Statistics.

At December 31, 1992, the Company had 7,369 full-time employees (see Operations Review and Cost Reduction).

Item 1. BUSINESS (Continued).

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 (b)	Reserve(c)
1992	21,697	17,525	3.4%	17,102	4,595
1991	21,849	16,952	(5.9)	16,831	5,018
1990	21,949	18,007	5.0	17,795	4,154

(a) The Company peak load includes interruptible load at the time of peak of 463 MW in 1992, 341 MW in 1991 and 347 MW in 1990.

(b) The Company firm peak load excludes interruptible load at the time of system peak and includes 40 MW in 1992, 220 MW in 1991 and 135 MW in 1990 of load associated with certain wholesale customers who were purchasing non-firm energy from sources other than The Company.

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

The peak load changes resulted primarily from customer growth in the service area offset by weather factors. The peak load in 1992 occurred on August 10. Included in the 1992 net capability was 1,771 MW of firm purchased capacity, including 1,691 MW of cogeneration and small power production. The Company expects to continue to purchase capacity in the future from various sources. (See Fuel Supply and Purchased Power and Note 14 to Financial Statements.)

Firm peak load increases over the next ten years are expected to average approximately 2.1% annually, after giving effect to an aggressive load management program (including interruptible contracts). The Company's ten year system integrated resource plan (Resource Plan) provides for meeting the increases in required net capability through the completion of nuclear, lignite and gas/oil-fueled combustion turbine capacity additions, through purchased power capacity (including cogeneration and small power production) and through the Company's load management programs. Such load management programs 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 two year deferral for the in-service dates of the Twin Oak lignite units (Twin Oak) and 1,290 MW of combined cycle combustion turbines. The in-service dates for simple-cycle combustion turbines, totaling 290 MW of capacity, have been accelerated three years when compared to the prior Resource Plan. The components of the Resource Plan (see Item 2, Properties — Construction Program) are as follows:

Resource Additions	Resource Plan 1993-2002 Capability (MW)	Resource Plan 1993-2002 Percent
Combustion Turbines	1,580	23%
Lignite	1,500	22
Purchased Power	1,450	21
Load Management	1,235	18
Nuclear	1,150	16
Total	6,915	100%

FUEL SUPPLY AND PURCHASED POWER

Net input for 1992 was 86,070 million kilowatt-hours (kWh) of which 74,652 million kWh were generated by the Company. During this period, 806,582,612 million British thermal units (Btu) of fuel (including 35,172,954 million Btu furnished by Aluminum Company of America (Alcoa) at no cost) were consumed for electric generation (see Lignite).

Average fuel and purchased power cost (excluding capacity charges) per kWh of net input was 1.85 cents for 1992, 1.82 cents for 1991 and 1.83 cents for 1990. 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		
Fuel for Electric Generation:	1992	1991	1990	1992	1991	1990
Gas	34.4%	37.3%	37.7%	$ 2.69	$2.47	$2.48
Oil	0.0 (a)	0.1	0.2	10.24	6.07	5.30
Lignite (b)	44.2	43.9	44.4	1.05	1.05	0.96
Nuclear	8.1	6.1	3.9	0.41	0.33	0.64 (c)
Total/Weighted Average Fuel Cost	86.7	87.4	86.2	$ 1.65	$1.62	$1.63
Purchased Power	13.3	12.6	13.8			
Total	100.0%	100.0%	100.0%			

(a) Fuel oil amounted to 0.02% of total fuel requirements.

(b) Lignite cost per ton to the Company was $13.19 for 1992, $13.48 for 1991 and $12.38 for 1990.

(c) Unit cost per million Btu in 1990 includes avoided cost of fuel during trial operations. The 1990 cost subsequent to commercial operation was $0.38 per million Btu.

Gas

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 1992 by Fuel Company. Fuel Company supplied approximately 49% of such fuel gas requirements under contracts with producers at the wellhead and under other contracts with dedicated reserves and 51% under contracts with commercial suppliers. Additional gas/oil-fueled combustion turbines, with an aggregate net capability of 1,580 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 declines and/or contracts expire, new contracts are expected to be negotiated to replenish or augment such supplies. During 1992, no curtailments were experienced under these contracts.

FUEL SUPPLY AND PURCHASED POWER — (Continued)

Gas — (concluded)

Fuel Company has negotiated gas purchase contracts, ranging in term 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 nor a firm purchase obligation from Fuel Company. During periods of winter peak gas demand, curtailments of gas deliveries have been experienced; 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.

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 21.3 billion cubic feet of gas in inventory at December 31, 1992. 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.

Oil

During 1992, the Company's utilization of fuel oil as an alternate source of boiler fuel amounted to 25,829 barrels or 0.02% of total fuel requirements. Fuel oil is stored at all nineteen of the principally gas-fueled generating stations. At December 31, 1992, 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 ficient movement of oil. Generally, oil required to replenish that oil removed from storage will be obtained through purchases in the open market.

FUEL SUPPLY AND PURCHASED POWER — (Continued)

Lignite

Lignite is used as the primary fuel in two units in service at the Big Brown generating station (Big Brown), three units at the Monticello generating station (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, which are or will be base loaded to operate at the maximum practical capacity factor, have been or will be constructed adjacent to surface mined lignite reserves. At the present time, the Company owns in fee or has under lease an estimated 905 million tons of proven reserves dedicated to existing power plants, plants under construction or plants in the advanced stages of design. 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). The Company continues to evaluate the use of western coal to supplement its existing lignite fuel supply. For information concerning applicable air quality standards, see Environmental Matters.

Lignite production operations at Big Brown, Monticello and Martin Lake are accompanied by an extensive reclamation program which returns the land to productive uses and includes a vegetation restoration program. Similar programs are planned for future lignite-fueled generating stations. For information concerning federal and state laws with respect to surface mining, see Environmental Matters.

Nuclear

The Company is operating one nuclear-fueled generating unit and is finalizing construction on a second unit 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, Comanche Peak Nuclear Generating Station and Item 2, Properties — Construction Program.)

In February 1993, pursuant to a license issued by the Nuclear Regulatory Commission (NRC), the Company loaded fuel and commenced low power testing of Unit 2. Enriched uranium has been purchased for Unit 1 through 1997 and the first three years of operation for Unit 2. Commitments have been obtained for fuel fabrication services for Unit 1 through 2002 and Unit 2 for the first ten years of operation. Uranium hexafluoride conversion services have been contracted for through 2003; and a uranium enrichment contract having a duration of approximately 22 years has been made with the U. S. Department of Energy. Commitments have been obtained for uranium ore concentrates for both units for the period 1994 through 2001. Additional contracts for uranium ore concentrates and nuclear fuel cycle services will be required in the future; however, it is not possible to predict the ultimate availability or cost thereof. The National Energy Policy Act of 1992 (Energy Act), which was enacted in October 1992, 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 will be 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 (currently estimated to be $1.8 million

FUEL SUPPLY AND PURCHASED POWER — (Concluded)

Nuclear — (concluded)

per year) will be in proportion to the amount of uranium separative services it uses. (See Competition for information pertaining to the Energy Act.)

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 will be 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 20 years and this storage capacity can be increased, subject to approval by the NRC.

Purchased Power

In 1992, the Company purchased 11,417 million kWh or approximately 13% 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 its system load and continues to investigate potential available sources. For information concerning the Resource Plan, see Peak Load and Capability and Note 14 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, 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 Public Utility Commission of Texas (PUC). (See Regulation and Rates for information pertaining to the method of recovery of purchased power and fuel costs.)

COMPETITION

The Company shares PUC certification in certain portions of its service area. In addition, some energy consumers in its service area have the ability to produce their own electricity or use alternative forms of energy. The level of competition is affected by, among other things, changes in regulation, the cost of energy alternatives and new technologies.

The Energy Act seeks to increase competition in electric generation and increase access to electric transmission systems. The Energy Act addresses a wide range of energy issues, including several matters affecting bulk power competition in the electric utility industry, nuclear licensing reform, nuclear plant decommissioning and energy efficiency. This legislation includes changes to the Public Utility Holding Company Act of 1935, the Public Utility Regulatory Policies Act of 1978, and the Federal Power Act. Implementation of this legislation through rulemaking is in process at the Federal Energy Regulatory Commission (FERC).

COMPETITION — (Concluded)

The Company is unable to predict the ultimate outcome of these developments or what impact, if any, they may have on its operations.

OPERATIONS REVIEW AND COST REDUCTION

In April 1992, the System Companies commenced a plan to better prepare the System Companies to operate in the rapidly changing business environment of the electric utility industry and to reduce costs. All aspects of System Companies' operations were examined to identify opportunities for effective changes in business processes and operating practices. Implementation of resulting changes in processes and practices has begun and will extend beyond 1993.

Related to this plan, the System Companies announced on June 1, 1992 an offer of enhanced voluntary early retirement to approximately 3,700 of the System Companies' 15,200 employees. All other regular full-time employees were offered a voluntary severance program. The election period for this program ended on September 1, 1992, with separation dates occurring through November 1, 1992. A total of 4,499 employees (about 30%) accepted the voluntary early retirement/severance program. The number of employee acceptances was about equally divided between employees electing early retirement and those electing voluntary severance. In September 1992, the System Companies deferred the cost of this program, which at December 31, 1992 was approximately $255 million. The Company has requested recovery of these costs in rates in Docket 11735 over a three year period as an offset to reductions in operating costs from changes in business processes and operating practices, which will result in the annual savings of approximately $117 million (see Regulation and Rates below).

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 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 do not have the prior approval of the PUC (see Rates). 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

REGULATION AND RATES — (Continued)

Regulation — (concluded)

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 the 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 have appealed the PUC's approval by filing an action which is currently pending in the 126th Judicial District Court of Travis County, Texas. (See Peak Load and Capability and Item 2, Properties — Construction Program.)

The System Companies are also subject to various other federal, state and local regulations. (See Comanche Peak Nuclear Generating Station and Environmental Matters.)

Rates

Pursuant to a PUC rule, the recovery of fuel costs is provided through fixed fuel factors. The rule requires refunds of material over-recoveries of fuel cost revenues and reductions in the fixed fuel factors in the event that the utility is materially over-recovered and projects that it will materially over-recover its known or reasonably predictable fuel costs. Material, as defined in the rule, is the lesser of $40 million or 4% of the annual known or reasonably predictable fuel costs most recently approved by the PUC. Final reconciliation of fuel costs is to be made in a utility's general rate case or at a reconciliation proceeding. The rule also provides for an emergency request to increase the fixed fuel factors, which must be acted upon within thirty days on an interim basis by the PUC, if reasonably unforeseeable circumstances have resulted in a material under-recovery of known or reasonably predictable fuel costs. Reconciliation of fuel costs takes place in a general rate case and may be requested otherwise if it has either been over one year since the utility's last fuel reconciliation or the utility has materially under-recovered its known or reasonably predictable fuel costs. In such reconciliation, the utility has the burden of proving that it has generated electricity efficiently, maintained effective cost controls, its non-affiliated fuel and fuel-related contracts have produced the lowest reasonable cost of fuel to ratepayers, and, for fuels acquired from affiliates, all fuel-related expenses are reasonable and necessary and that the prices charged are no higher than prices charged by the supplying affiliate to other of its affiliates or divisions or to unaffiliated persons or corporations for the same item or class of items. Under-recovery reconciliation will be granted only for that portion of fuel costs increased by conditions or events beyond the utility's control. Interest will be paid or received by the utility on any over- or under-recovery of fuel costs at the utility's composite cost of capital as established by the PUC in the utility's most recent general rate case. The rule imposes penalties of up to 10% in the event that interim refunds, when required, are not timely requested and in the event that an emergency increase is granted when there was no emergency. In addition, the PUC rules contain a provision which generally allows recovery through a Power Cost Recovery Factor (PCRF), on a monthly basis, of purchased power capacity costs not included in base rates from qualifying cogenerators and qualifying small power producers. The portion of purchased power costs for fuel is included in the fixed fuel factor.

In January 1993, the PUC amended its rule governing the recovery of fuel costs, effective May 1,

REGULATION AND RATES — (Continued)

Rates — (concluded)

1993. Under the amended rule, eligible fuel costs will continue to be recovered through fuel factors. The amended 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 will be 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 over- or under-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. The rule also contains a procedure 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. In a final reconciliation, a utility will have 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 amended rule provides for recovery of purchased power capacity costs that are not otherwise included in base rates, for purchases from qualifying facilities, on a monthly basis through a PCRF. The energy-related costs of such purchases will be included in the fuel factor. Penalties of up to 10% will be imposed in the event that either 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.

Pending Rate Request

On January 22, 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. Such request reflects, among other things, costs associated with the anticipated commercial operation of Comanche Peak Unit 2, costs associated with Comanche Peak Unit 1 capital investment after the end of the Docket 9300 test year (see below), additional ad valorem taxes and certain postretirement benefit costs. The proposed rate adjustments, if approved, would affect all classes of service and are estimated to increase annual operating revenues by approximately $760 million, or 15.3%, based upon the test year ended June 30, 1992. The Company is unable to predict the extent to which this rate increase request will be granted. The Company expects to place new rates in effect, under bond, when Unit 2 of Comanche Peak achieves commercial operation which is scheduled for the peak season of 1993. The request to place additional amounts of Comanche Peak investment in rate base will be subject to a review by the PUC for prudence of costs incurred. In connection with the September 1991 rate order in Docket 9300, the PUC reviewed costs incurred through June 1989 on Unit 2 and through fuel load in February 1990 on Unit 1. At December 31, 1992, the Company had approximately $2.6 billion invested in Comanche Peak that had not been reviewed for prudence. The Company cannot predict the outcome of any future prudence review. The Company is also seeking reconciliation, under the fuel rule currently in effect, of approximately $4.6 billion of fuel costs incurred during the three year period ended June 30, 1992 (see Rates).

REGULATION AND RATES — (Continued)

Prior Rate Request

In January 1990, the Company made applications to the PUC (Docket 9300) and to its municipal regulatory authorities for upward adjustments in rates for electric service throughout its service area which would increase operating revenues by approximately $442 million, or 10.2%, based upon the test year ended June 30, 1989. Such request reflected costs associated with the commercial operation of Unit 1 of Comanche Peak. On August 13, 1990, pursuant to rules of the PUC, the Company placed its requested rate increase into effect, under bond, applicable to energy sales on or after such date.

In September 1991, the PUC issued a final order in Docket 9300. The order 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 addition, the order provided for refunds aggregating $56 million, including interest, principally with respect to fuel gas costs considered imprudent by the PUC. Such amount is being refunded to customers, with interest, over a two year period that began in November 1991.

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 order. Other parties to the PUC proceedings 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. In the judgment, the Court affirmed the prudence disallowance of $472 million with regard to certain costs associated with Comanche Peak 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 concluded that upon remand the PUC must consider all factors relevant to the overall public interest, including all factors and considerations raised by the evidence presented by the Company, and should not base its decision solely on a "least-cost" comparison of generation alternatives in its determination of reasonable value in connection with these transactions. The Court also found that the PUC erred in ordering a refund of approximately $2.5 million with respect to certain fuel gas costs considered imprudent by the PUC. In addition, the Court indicated that the PUC erred in its calculation of the amount of the Company's cash working capital. 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 current rates approved in the PUC's 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.

In October 1992, the General Counsel's office of the PUC filed a complaint against the Company requesting that the PUC review certain aspects of the Company's implementation of bonded rates in Docket 9300 for the period during which such rates were in effect. The complaint alleges primarily that during such period the Company should not have accrued approximately $70 million of an allowance for funds used during construction (AFUDC) related to the Unit 2 investment which was

REGULATION AND RATES — (Concluded)

Prior Rate Request — (concluded)

subsequently included as CWIP in rate base pursuant to the rate order in Docket 9300. The Company disagrees with the General Counsel's position and expects that the issue will be resolved during the pendency of, or in connection with, Docket 11735.

In December 1992, the PUC ruled in another electric utility's proceeding that an "actual taxes paid" method of accounting for income taxes proposed by an intervenor in that proceeding was the appropriate ratemaking approach based on its interpretation of two state court rulings. Generally, an "actual taxes paid" approach to ratemaking treatment for income taxes proposed by intervenors involves utilizing tax benefits generated by costs which are not allowed in rates to reduce rates charged to customers. The tax benefits associated with the Comanche Peak costs disallowed in Docket 9300 are the tax benefits that primarily could be affected under this approach. According to a Private Letter Ruling issued to the Company by the Internal Revenue Service, such ratemaking treatment to the extent it relates 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. Violation of the normalization rules would result in a significant adverse effect on the Company's results of operations and liquidity. The Company believes that the court rulings cited by the PUC in its recent decision are not controlling as regards rate making treatment of the tax benefits associated with the costs of Comanche Peak. Accordingly, the Company is prepared to strongly oppose such ratemaking treatment for income taxes in Docket 11735 on the same basis as it is currently opposing the imposition of such rate making treatment in the appeals by the other parties of the rate order in Docket 9300.

See Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 12 to Financial Statements.

COMANCHE PEAK NUCLEAR GENERATING STATION

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. In April 1990, the NRC issued a full power operating license for Unit 1. The construction permit for Unit 2 is in effect and has been extended until a "latest date for completion" of August 1, 1995. In February 1993, pursuant to a license issued by the NRC, the Company loaded fuel and commenced low power testing of Unit 2. For information relating to cost and schedule estimates see Item 2, Properties — Construction Program.

In August 1992, following action by the NRC staff which extended the construction permit for 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. The Company does not believe that any such proceedings will affect the licensing of Unit 2 for full power operation.

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 scheduled environmental expenditures).

Air

Under the Texas Clean Air Act, the Texas Air Control Board (TACB) 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 Amendments of 1990 (Clean Air Act), which have also been adopted by the TACB, 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. Generating facilities under construction have received state and federal permits and are designed to comply with applicable statutes and regulations.

The federal 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 Phase II requirements currently are met by all but four of the Company's generating units. Because the sulfur dioxide emissions from these four units are relatively low and alternatives are available to enable these units to reduce sulfur dioxide emissions or utilize compensatory additional 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. On January 11, 1993, the EPA issued its "core" regulations to implement the sulfur dioxide reduction program. The Company is reviewing these regulations and is preparing a compliance plan 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. Utilities will be permitted to transfer allowances within their own systems and to buy or sell allowances in a new allowance trading market to be established under the Clean Air Act. The EPA will grant a maximum number of allowances annually to the Company based on the amount of emissions from units in operation in 1985. 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 currently required nitrogen oxide limits in 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 by

ENVIRONMENTAL MATTERS — (Continued)

Air — (concluded)

1996. 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 and such installation has begun.

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 of 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. 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 recovered through rates, as similar costs have been recovered in the past.

Water

The Texas Water Commission (TWC) and the EPA have jurisdiction over all water discharges (including storm water) from generating stations and mining areas. The Company's generating stations 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 TWC 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 TWC. The Company possesses all necessary permits for these activities from the TWC 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. 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 TWC has issued regulations under the Texas act applicable to the Company generating units. The Company has registered its solid waste disposal sites and has obtained or applied for such permits as are required by such regulations.

ENVIRONMENTAL MATTERS — (Concluded)

Other — (concluded)

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 radioactive 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 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.

Item 2. PROPERTIES.

At December 31, 1992, the Company owned or leased and operated the following units:

Electric Generating Units	Fuel Source	Net Capability (MW)	%
47	Natural Gas (a)	11,936	59.9
9	Lignite	5,845	29.3
2	Nuclear	1,150	5.8
10	Diesel	20	0.1
15	Combustion Turbines (b) ..	975	4.9
	Total	19,926	100.0

(a) Thirty-eight (38) natural gas units are designed to operate on fuel oil for short periods when gas supplies are interrupted or curtailed. Five (5) natural gas units are designed to operate on fuel oil for extended periods.

(b) 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.

During the period from January 1, 1990 to December 31, 1992, the Company made gross property additions of approximately $2,655,106,000 and retirements of property aggregating approximately $172,249,000. Such gross additions amounted to approximately 12.9% of electric plant at December 31, 1992.

Item 2. PROPERTIES (Continued).

CONSTRUCTION PROGRAM

Construction expenditures, excluding AFUDC (see Note 1 to Financial Statements), for the years 1993 through 1995 are estimated as follows:

	1993	1994	1995
Electric Property:	Thousands of Dollars		
Production			
Comanche Peak Unit 2	$ 82,000	$ —	$ —
Other Production	117,000	144,000	367,000
Other Production - Environmental (a)	41,000	98,000	68,000
Total Production	240,000	242,000	435,000
Transmission	49,000	43,000	62,000
Distribution	262,000	238,000	240,000
General	29,000	37,000	53,000
Total	$580,000	$560,000	$790,000
Such expenditures do not include amounts for:			
Nuclear Fuel (excluding AFUDC)	$ 5,000	$ 5,000	$ 68,000

(a) The System Companies are subject to federal, state and local regulations dealing with environmental protection (see Item 1. Business—Environmental Matters). Such expenditures for existing units approximated $25,400,000 for 1992, $10,400,000 for 1991 and $15,500,000 for 1990.

Comanche Peak Nuclear Generating Unit 2

Unit 2 is scheduled for service for the peak season of 1993. At December 31, 1992, the Company had $4.22 billion invested in Unit 2 (net of $485 million included in the reserve for regulatory disallowances required by the PUC order in Docket 9300, see Note 12 to Financial Statements), including AFUDC. The estimated cash requirements in 1993 to complete Unit 2 are approximately $82 million. AFUDC accruals for Unit 2, which approximated $30 million for the month of January 1993, will continue until the unit is in commercial operation. Also, in January 1993, pursuant to adopting a new accounting standard for income taxes which precludes net-of-tax accounting for income taxes, the Company increased previously recorded AFUDC for Unit 2 by $219 million with a corresponding increase in deferred income taxes.

Other Generating Units

The Company's Resource Plan includes two lignite-fueled 750 MW units at Twin Oak scheduled for service for the peak seasons of 1999 and 2000, respectively. Estimated construction expenditures, excluding AFUDC, for the 1993-1995 period include approximately $221 million applicable to these generating units. Active construction and the accrual of AFUDC on Twin Oak, suspended in September 1987 due to forecast changes in load growth, is expected to resume in 1995. Construction activities for the 290 MW of gas/oil-fueled combustion turbines planned for the peak season of 1998 are expected to begin in 1994. Estimated construction expenditures, excluding AFUDC, for the 1993-1995 period include approximately $5 million applicable to this generating capacity.

Item 2. PROPERTIES (Continued).

CONSTRUCTION PROGRAM — (Concluded)

Other Generating Units — (concluded)

The remainder of the Company's Resource Plan includes 1,290 MW of gas/oil-fueled generating combustion turbine units, none of which require significant construction expenditures in the 1993-1995 period reflected above. (See Item 1, Business — Peak Load and Capability.)

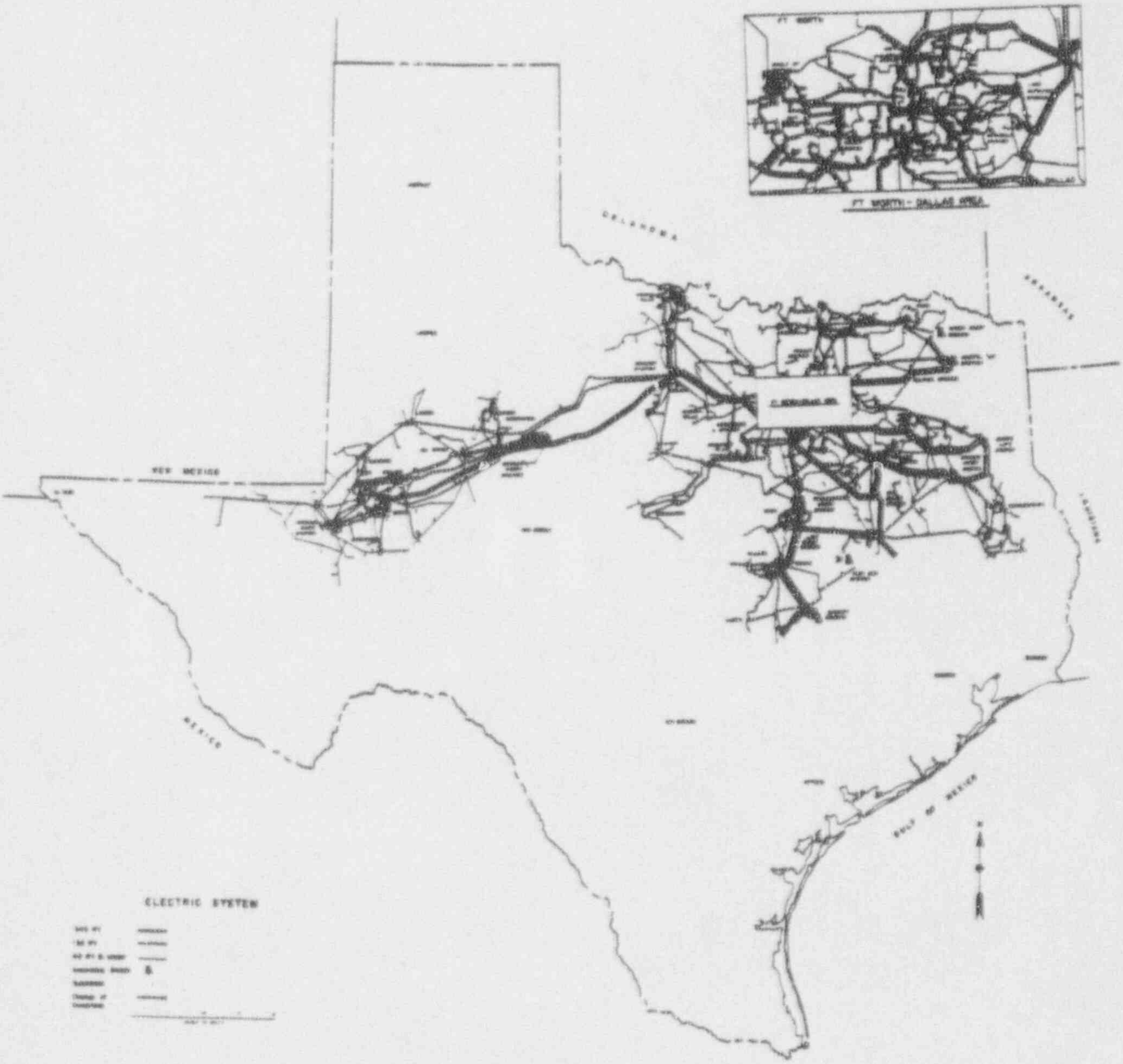
The effects of inflation on construction costs, the reevaluation of growth expectations or additional regulatory requirements may result in changes in estimated completion costs and in-service dates for certain generating units in design or under construction. Actual expenditures and dates of completion may further vary because of other uncertain factors such as licensing delays, changes in peak load requirements and cost and availability of fuel, labor, materials and capital. Commitments in connection with the construction program, principally for generating stations and related facilities, are generally revocable subject to reimbursement to manufacturers for expenditures incurred or other cancellation penalties.

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

Item 2. PROPERTIES (Concluded).

THE COMPANY SYSTEM

December 31, 1992



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, [illegible]e 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. On January 29, 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 6 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,				
	1992	1991*	1990	1989	1988
Total assets — end of year (thousands)	$17,962,812	$17,093,474	$17,387,276	$16,173,648	$14,828,250
Electric plant — gross — end of year (thousands)	$21,957,681	$20,865,047	$19,693,580	$18,116,758	$16,370,676
Accumulated depreciation and amortization — end of year	3,790,626	3,417,856	3,038,302	2,762,101	2,558,282
Reserve for regulatory disallowances — end of year	1,308,460	1,308,460	—	—	—
Construction expenditures (including allowance for funds used during construction)	1,107,555	1,195,680	1,431,647	1,793,890	1,542,974
Capitalization — end of year (thousands)					
Long-term debt	$ 7,280,301	$ 7,253,626	$ 6,750,635	$ 6,079,503	$ 5,872,613
Preferred stock:					
Not subject to mandatory redemption	909,564	1,007,728	1,007,728	1,007,732	909,582
Subject to mandatory redemption	418,748	425,758	426,737	329,009	328,770
Common stock equity	6,198,208	5,741,437	6,452,690	5,814,013	5,278,697
Total	$14,806,821	$14,428,549	$14,637,790	$13,230,257	$12,389,662
Embedded interest cost on long-term debt — end of year	9.2%	9.7%	9.8%	9.8%	9.9%
Embedded dividend cost on preferred stock — end of year	8.4%	8.5%	8.6%	8.3%	8.3%
Income (loss) before cumulative effect of a change in accounting principle (thousands)	$740,216	$(289,173)	$964,276	$886,176	$747,062
Cumulative effect of a change in accounting for unbilled revenue (Net of taxes of $41,679,000)(Note 14)	80,907	—	—	—	—
Net income (loss)(thousands)	$821,123	$(289,173)	$964,276	$886,176	$747,062
Dividends declared on common stock (thousands)	$645,260	$ 650,940	$607,230	$542,298	$500,968
Ratio of earnings to fixed charges	2.5	0.3	2.5	2.6	2.6
Allowance for funds used during construction as percent of earnings to common stock	43.3%	— %	73.1%	65.1%	59.3%
Return on average common stock equity	11.8%	(6.7)%	13.8%	14.0%	12.9%
Cash flows from operations (less dividends paid) as a percent of cash construction expenditures	38.9%	27.1%	24.0%	12.6%	10.7%

* Certain financial statistics for the year 1991 were affected by the Company's recording a charge against earnings, representing provisions for disallowances in the rate order issued by the Public Utility Commission of Texas in Docket 9300. (See Note 12 to Financial Statements.)

Item 6. SELECTED FINANCIAL DATA (Concluded).

OPERATING STATISTICS

	Year Ended December 31,				
	1992	1991	1990	1989	1988
ELECTRIC ENERGY GENERATED AND PURCHASED (MWh)					
Generated — net station output	74,652,339	76,326,601	76,044,403	74,925,395	73,493,397
Purchased and net interchange	11,417,251	11,027,061	12,179,724	12,588,899	12,095,385
Total generated and purchased	86,069,590	87,353,662	88,224,127	87,514,294	85,588,782
Company use, losses and unaccounted for	5,747,156	4,996,123	4,496,294	5,571,768	4,864,236
Total electric energy sales	80,322,434	82,357,539	83,727,833	81,942,526	80,724,546
ELECTRIC ENERGY SALES (MWh)					
Residential	27,266,411	28,505,885	28,157,802	27,294,613	26,722,342
Commercial	22,959,464	23,012,114	23,429,101	22,539,351	21,899,895
Industrial	21,108,894	21,482,750	21,839,196	21,377,542	21,516,862
Government and municipal	5,032,780	5,056,868	4,914,503	4,683,259	4,583,505
Total general business	76,367,549	78,057,617	78,340,602	75,894,765	74,722,604
Other electric utilities	3,954,885	4,299,922	5,387,231	6,047,761	6,001,942
Total electric energy sales	80,322,434	82,357,539	83,727,833	81,942,526	80,724,546
OPERATING REVENUES (thousands)					
Residential	$1,995,767	$2,043,421	$1,859,239	$1,752,679	$1,704,219
Commercial	1,405,546	1,391,995	1,266,030	1,228,672	1,182,869
Industrial	849,365	852,952	801,821	817,802	815,887
Government and municipal	304,286	303,597	273,596	251,941	245,249
Total general business	4,554,964	4,591,965	4,200,686	4,051,094	3,948,224
Other electric utilities	209,170	228,075	232,755	245,821	239,937
Total from electric energy sales	4,764,134	4,820,040	4,433,441	4,296,915	4,188,161
Other operating revenues (including unbilled revenue and over/under-recovered fuel revenue)*	142,561	71,482	107,474	21,650	(36,343)
Total operating revenues	$4,906,695	$4,891,522	$4,540,915	$4,318,565	$4,151,818
ELECTRIC CUSTOMERS (end of year)					
Residential	1,952,916	1,921,119	1,900,005	1,875,524	1,858,727
Commercial	210,185	205,555	205,359	210,824	209,520
Industrial	21,969	22,156	22,214	22,024	22,179
Government and municipal	28,204	27,719	24,538	23,434	20,037
Total general business	2,213,274	2,176,549	2,152,116	2,131,806	2,110,463
Other electric utilities	243	247	63	64	64
Total electric customers	2,213,517	2,176,796	2,152,179	2,131,870	2,110,527
RESIDENTIAL STATISTICS (excludes master-metered customers, kWh sales and revenues)					
Average kWh per customer	13,329	14,099	14,050	13,754	13,505
Average revenue per kWh	7.41¢	7.26¢	6.69¢	6.50¢	6.48¢
Industrial classification includes service to Alcoa-Sandow:					
Electric energy sales (MWh)	3,157,852	3,359,824	3,517,431	3,276,303	3,525,416
Operating revenues (thousands)	$56,043	$55,987	$55,274	$56,985	$56,608

* 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 OPERATIONS.

Liquidity and Capital Resources

The primary capital requirements of Texas Utilities Electric Company (Company) in 1992 and as estimated for 1993 through 1995 are as follows:

	1992	1993	1994	1995
		Thousands of Dollars		
Cash construction expenditures (excluding allowance for funds used during construction)	$ 831,000	$580,000	$560,000	$790,000
Nuclear fuel (excluding allowance for funds used during construction)	23,000	5,000	5,000	68,000
Maturities and redemptions of long-term debt, sinking fund requirements and redemptions of preferred stock	1,807,000	174,000	157,000	122,000
Total	$2,661,000	$759,000	$722,000	$980,000

For detail concerning major construction work now in progress or contemplated by the Company and the commitments with respect thereto, see Item 2, Properties — Construction Program and Note 14 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. For 1992, approximately 39% of the cash needed for construction expenditures was generated from operations by the Company. The Company expects internal cash generation to improve due to reductions in construction expenditures and the anticipated effects of the rate increase requested in Docket 11735 (see below).

In April 1992, the Texas Utilities Company System (System Companies) commenced a plan to better prepare the System Companies to operate in the rapidly changing business environment of the electric utility industry and to reduce costs. All aspects of the System Companies' operations were examined to identify opportunities for effective changes in business processes and operating practices. Implementation of resulting changes in processes and practices has begun and will extend beyond 1993.

Related to this plan, the System Companies announced on June 1, 1992 an offer of enhanced voluntary early retirement to approximately 3,700 of the System Companies' 15,200 employees. All other regular full-time employees were offered a voluntary severance program. The election period for this program ended on September 1, 1992, with separation dates occurring through November 1, 1992. A total of 4,499 employees (about 30%) accepted the voluntary early retirement/severance program. The number of employee acceptances was about equally divided between employees electing early retirement and those electing voluntary severance. In September 1992, the System Companies deferred the cost of this program, which at December 31, 1992 was approximately $255 million. The Company has requested recovery of these costs in rates in Docket 11735 (see following paragraph and Note 12 to Financial Statements) over a three year period as an offset to reductions in operating costs from changes in business processes and operating practices, which will result in net annual savings of approximately $117 million. The voluntary retirement/severance program was funded through a combination of pension plan assets (approximately $355 million) and general funds (approximately $84 million) of the Company and will not materially affect the Company's financial position or results of operations. (See Note 9 to Financial Statements.)

Liquidity and Capital Resources — (continued)

On January 22, 1993, the Company made applications to the Public Utility Commission of Texas (PUC) in Docket 11735 and to its municipal regulatory authorities for upward adjustments in rates for electric service throughout its service area. Such request reflects, among other things, costs associated with the anticipated commercial operation of Unit 2 of Comanche Peak nuclear generating station (Comanche Peak), costs associated with Comanche Peak Unit 1 capital investment after the end of the Docket 9300 test year (see below), additional ad valorem taxes and certain postretirement benefit costs. The proposed rate adjustments, if approved, would affect all classes of service and are estimated to increase annual operating revenues by approximately $760 million, or 15.3%, based upon the test year ended June 30, 1992. The Company is unable to predict the extent to which this rate increase request will be granted. The Company expects to place new rates in effect, under bond, when Unit 2 of Comanche Peak achieves commercial operation which is scheduled for the peak season of 1993. The request to place additional amounts of Comanche Peak investment in rate base will be subject to a review by the PUC for prudence of costs incurred. In connection with the September 1991 rate order in Docket 9300, the PUC reviewed costs incurred through June 1989 on Unit 2 and through fuel load in February 1990 on Unit 1. At December 31, 1992, the Company had approximately $2.6 billion invested in Comanche Peak that had not been reviewed for prudence. The Company cannot predict the outcome of any future prudence review. Accordingly, no provision for loss, if any, has been made in the financial statements of the Company. The Company is also seeking reconciliation, under the fuel rule currently in effect, of approximately $4.6 billion of fuel costs incurred during the three year period ended June 30, 1992.

In September 1992, the 250th Judicial District Court of Travis County, Texas, entered a judgment in the appeals of the Company's Docket 9300 which granted a $44[illegible] million, or 10.2% increase in operating revenues. In the judgment, the Court affirmed the prudence disallowance of $472 million with regard to certain costs associated with Comanche Peak 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 concluded that upon remand the PUC must consider all factors relevant to the overall public interest, including all factors and considerations raised by the evidence presented by the Company, and should not base its decision solely on a "least-cost" comparison of generation alternatives in its determination of reasonable value in connection with these transactions. The Court also found that the PUC erred in ordering a refund of approximately $2.5 million with respect to certain fuel gas costs considered imprudent by the PUC. In addition, the Court indicated that the PUC erred in its calculation of the amount of the Company's cash working capital. The Court recognized that on remand the PUC may adjust the amount of construction work in progress (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 current rates approved in the PUC's 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. The disallowed Comanche Peak related costs are reflected as reserves for regulatory disallowances on the Company's balance sheet pending the outcome of any further appeals or reconsideration by the PUC (see Item 1, Business — Rates, and Note 12 to Financial Statements).

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

Liquidity and Capital Resources — (continued)

In October 1992, the General Counsel's office of the PUC filed a complaint against the Company requesting that the PUC review certain aspects of the Company's implementation of bonded rates in Docket 9300 for the period during which such rates were in effect. The complaint alleges primarily that during such period the Company should not have accrued approximately $70 million of allowance for funds used during construction (AFUDC) related to the Unit 2 investment which was subsequently included as CWIP in rate base pursuant to the rate order in Docket 9300. The Company disagrees with the General Counsel's position and expects that the issue will be resolved during the pendency of, or in connection with, Docket 11735.

In December 1992, the PUC ruled in another electric utility's proceeding that an "actual taxes paid" method of accounting for income taxes proposed by an intervenor in that proceeding was the appropriate ratemaking approach based on its interpretation of two state court rulings. Generally, an "actual taxes paid" approach to ratemaking treatment for income taxes proposed by intervenors involves utilizing tax benefits generated by costs which are not allowed in rates to reduce rates charged to customers. The tax benefits associated with the Comanche Peak costs disallowed in Docket 9300 are the tax benefits that primarily could be affected under this approach. According to a Private Letter Ruling issued to the Company by the Internal Revenue Service, such ratemaking treatment, to the extent it relates 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. Violation of the normalization rules would result in a significant adverse effect on the Company's results of operations and liquidity. The Company believes that the court rulings cited by the PUC in its recent decision are not controlling as regards ratemaking treatment of the tax benefits associated with the costs of Comanche Peak. Accordingly, the Company is prepared to strongly oppose such ratemaking treatment for income taxes in Docket 11735 on the same basis as it is currently opposing the imposition of such ratemaking treatment in the appeals by the other parties of the rate order in Docket 9300.

Although the Company cannot predict the outcome of its appeal of the Docket 9300 rate decision, future regulatory actions or any changes in economic and securities market conditions, no changes are expected in trends or commitments which might significantly alter its basic 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, 1992, consisted of approximately 49% long-term debt, 9% preferred stock and 42% common stock equity.

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

Liquidity and Capital Resources — (continued)

Financings in 1992 by the Company included the following:

Long-Term Debt:

Month	Principal Amount	Description
February	$ 150,000,000	8-1/8% First Mortgage and Collateral Trust Bonds due 2002
February	175,000,000	8-7/8% First Mortgage and Collateral Trust Bonds due 2022
April	50,000,000	6-3/4% Collateralized Pollution Control Revenue Bonds due 2022
April	100,000,000	8-1/4% First Mortgage and Collateral Trust Bonds due 2004
April	100,000,000	9% First Mortgage and Collateral Trust Bonds due 2022
June	150,000,000	7-1/8% First Mortgage and Collateral Trust Bonds due 1997
June	147,000,000	8% First Mortgage and Collateral Trust Bonds due 2002
June	33,000,000	6-5/8% Collateralized Pollution Control Revenue Bonds due 2022
August	175,000,000	6-3/8% First Mortgage and Collateral Trust Bonds due 1997
August	150,000,000	7-3/8% First Mortgage and Collateral Trust Bonds due 2001
August	175,000,000	8-1/2% First Mortgage and Collateral Trust Bonds due 2024
November	40,000,000	6.55% Collateralized Pollution Control Revenue Refunding Bonds due 2022
November	16,935,000	6.70% Collateralized Pollution Control Revenue Bonds due 2022
November	100,000,000	7-3/8% First Mortgage and Collateral Trust Bonds due 1999
November	200,000,000	8-3/4% First Mortgage and Collateral Trust Bonds due 2023
December	46,660,000	6-1/2% Collateralized Pollution Control Revenue Refunding Bonds due 2027
Total	$1,808,595,000	

Common Stock:

Month	Shares	Net Proceeds	Description
March	3,875,000	$199,562,500	Without par value
December	3,600,000	201,600,000	Without par value
Total		$401,162,500	

In 1992, the Company redeemed or made principal payments of $1,807,382,000 on long-term debt and preferred stock, of which $1,570,000,000 represents the early redemption of higher coupon debt. The replacement of higher coupon debt during 1992 reduced interest expense by approximately $25,000,000 for the year or $37,000,000 on an annualized basis. Early redemptions of long-term debt and preferred stock may occur from time to time in amounts presently undetermined. For information regarding short-term financings of the Company, see Note 3 to Financial Statements.

In January 1993, the Company issued and sold 5,000,000 depository shares each representing 1/4th of a share of $8.20 Cumulative Preferred Stock for $121,062,500.

The Company expects to sell additional debt and equity securities as needed including (i) the possible future sale of up to 750,000 shares of Cumulative Preferred Stock ($100 par value), or depository shares representing fractional interests in shares of such Cumulative Preferred Stock, currently registered with the Securities and Exchange Commission (Commission) for offering pursuant to Rule 415 under the Securities Act of 1933 and (ii) $800,000,000 of First Mortgage and Collateral Trust Bonds with respect to which a registration statement has been filed with the Commission in contemplation of offering pursuant to Rule 415. Because of the planned reduction in construction expenditures and the anticipated

Liquidity and Capital Resources — (concluded)

effects of the rate increase requested in Docket 11735, the scheduled reduction in the Company's joint lines of credit is not expected to materially affect the Company's ability to fund its capital requirements. For information regarding short-term financings of the Company, see Note 3 to Financial Statements.

In November 1990, the federal Clean Air Act Amendments of 1990 (Clean Air Act) were enacted 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 sulphur dioxide emission standards by 2000 (Phase II). The Company's generating units are not affected by Phase I requirements. The Phase II requirements are currently met by all but four of the Company's generating units. Other provisions of the Clean Air Act may require the Company to take other actions; however, only certain parts of the regulations implementing requirements have been published as final rules. Until these regulations have been promulgated and specific state requirements developed, the Company will not be able to fully determine the cost or method of compliance with the major requirements.

The Company's capital requirements have not been significantly affected by the Clean Air Act's requirements. 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 recovered through rates, as similar costs have been recovered in the past. (See Item 1, Business — Environmental Matters, and Note 14 to Financial Statements.)

The National Energy Policy Act of 1992 (Energy Act) was enacted in October 1992. The Energy Act seeks to increase competition in electric generation and increase access to electric transmission systems. The Energy Act addresses a wide range of energy issues, including several matters affecting bulk power competition in the electric utility industry, nuclear licensing reform, nuclear plant decommissioning and energy efficiency. This legislation includes changes to the Public Utility Holding Company Act of 1935, the Public Utility Regulatory Policies Act of 1978 and the Federal Power Act. The Company is unable to predict the impact of this legislation on its operations. (See Item 1, Business — Competition, and Note 14 to Financial Statements.)

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

Results of Operations

Operating revenues increased 0.3% and 7.7% for the years ended December 31, 1992 and 1991, respectively. The following table details the factors contributing to these changes:

Factors	Increase (Decrease) 1992	1991
	Thousands of Dollars	
Base rate revenue	$(57,824)	$ 548,973
Fuel revenue	42,161	(73,827)
Power cost recovery factor revenue	(89)	(129,073)
Unbilled revenue and other	30,925	4,534
Total	$ 15,173	$ 350,607

Results of Operations — (continued)

Base rate revenue decreased in 1992 as a result of lower energy sales and increased in 1991 due to higher rate levels implemented in late 1990. Energy sales decreased 2.5% for 1992 and 1.6% for 1991 due to decreased customer usage resulting from milder weather and unfavorable economic conditions, partially offset by an increase in customers. Fuel revenues increased in 1992 primarily due to fuel refunds in 1991, partially offset by decreased energy sales. Fuel revenues decreased in 1991 primarily due to a lower fuel factor and a PUC ordered refund of disallowed fuel gas purchases. (See Note 12 to Financial Statements.) The increase in unbilled revenue and other in 1992 was primarily due to the accrual of unbilled revenue. (See Note 15 to Financial Statements.)

Fuel and purchased power expense increased 1.1% for 1992 and decreased 1.3% for 1991. Fuel and purchased power expense increased for 1992 primarily due to the increased price of gas which more than offset the decrease in generation. The decrease in 1991 was the result of lower cost of nuclear fuel and gas and reduced off-system power purchases. (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, decreased 1.9% for 1992 and increased 18.7% for 1991. Operation and maintenance expenses decreased in 1992 primarily due to decreased employee related costs and management's efforts to further reduce other costs through the cost reduction program. (See Note 13 to Financial Statements.) 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. Operation, maintenance and depreciation expense increased in 1991 primarily due to the commercial operation of Comanche Peak Unit 1. Amortization of rate case expenses related to Docket 9300 and increased employee related costs also contributed to the 1991 increase in operation expense. Federal income taxes increased in 1992 due to changes in the amortization of tax differences resulting from the recording of the Company's Docket 9300 rate order, partially offset by deductions related to the cost reduction program and the refinancing of Company debt. The increase in taxes other than income in 1991 reflects the effects of legislation which increased ad valorem taxes. In January 1992, the Texas Supreme Court declared such legislation unconstitutional and instructed the State legislature to provide a revised law for school funding by June 1, 1993, with the current law to remain in effect, subject to a referendum in the State of Texas on May 1, 1993. An increase in franchise taxes and state and local gross receipts taxes also contributed to the increase in 1991.

AFUDC decreased 16.4% and 41.1% in 1992 and 1991, respectively. The decrease for both years 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. A reduction in AFUDC rates also contributed to the decrease in 1992. The reduction in 1991 was also due to the full year's effect of the discontinuation of the accrual of AFUDC on Comanche Peak Unit 1 when the unit was placed in commercial operation in August 1990. (See Note 1 to Financial Statements.)

Other income and deductions — net decreased for 1992 and increased in 1991, primarily due to changes in interest income for each year related to the changes in temporary cash investments between years.

Federal income taxes — other income increased in 1992 and decreased in 1991 due to the effect of recording the taxes associated with the provision for regulatory disallowances in 1991. (See Notes 8 and 12 to Financial Statements.)

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

Results of Operations — (concluded)

Total interest charges, excluding AFUDC, decreased 6.0% for 1992 and increased 6.0% for 1991. Interest on mortgage bonds decreased in 1992 due to retirements and redemptions of certain higher rate issues. Interest on mortgage bonds increased in 1991 as a result of new issues sold during the period and annualized interest on issues sold in prior periods. The continuing retirement of debt incurred on the purchases of the minority ownership interests in Comanche Peak resulted in the reduction of interest on other long-term debt in 1991 and 1992. Other interest expense decreased in 1992 and increased in 1991 as a result of recording interest related to the settlement of prior years' federal income tax returns and interest associated with the PUC's order to refund disallowed fuel gas costs in 1991.

The factors mentioned above along with the change in accounting for unbilled revenue (see Note 15 to Financial Statements) and the recording of the provision for regulatory disallowances in 1991 (see Note 12 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 is not provided for in current rates but which is included in Docket 11735.

Preferred stock dividends decreased 2.6% in 1992 primarily due to a reduction in adjustable dividend rates and increased 2.8% in 1991 as a result of the full periods' effect of prior period preferred stock issuances.

Accounting Changes

In December 1990, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions" (Statement 106), which is effective for fiscal years beginning after December 15, 1992. Statement 106 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 unfunded actuarial present value of employee service rendered to the date of adoption (transition obligation at January 1, 1993) is approximately $300 million. Statement 106 allows the transition obligation to be either recognized immediately as the cumulative effect of a change in accounting principle or amortized evenly over the longer of the average remaining service lives of covered employees or 20 years. The Company intends to recognize the transition obligation over 20 years. The Company's total annual benefits cost under Statement 106, assuming amortization of the transition obligation over 20 years, is approximately $46 million.

In December 1992, the PUC issued a proposed rule that would allow a request for a one time conversion from the "pay-as-you-go" method for ratemaking purposes to a method allowing recovery of accrual costs as defined by the PUC rule. The proposed rule would exclude recovery of the transition obligation from net periodic postretirement benefit cost as defined by Statement 106. If the rule is approved as proposed, net income would be adversely affected by approximately $10 million annually. The proposed rule is expected to be finalized in the first quarter of 1993.

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

Accounting Changes — (concluded)

In November 1992, the FASB issued Statement of Financial Accounting Standards No. 112, "Employers' Accounting for Postemployment Benefits" (Statement 112), which 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 operations.

In February 1992, the FASB issued Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes" (Statement 109), which is effective for fiscal years beginning after December 15, 1992. Statement 109, 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, initial application of Statement 109 in 1993 increased both total assets and liabilities by approximately $1.4 billion and the effect on net income is not considered material. Continuing application of Statement 109 is not expected to have a material effect on the Company's financial position or results of operations.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

TEXAS UTILITIES ELECTRIC COMPANY

STATEMENTS OF INCOME

	Year Ended December 31,		
	1992	1991	1990
		Thousands of Dollars	
OPERATING REVENUES	$4,906,695	$4,891,522	$4,540,915
OPERATING EXPENSES			
Fuel and purchased power	1,775,885	1,756,423	1,779,854
Operation	684,095	729,615	645,857
Maintenance	297,079	304,683	289,949
Depreciation and amortization	409,006	425,216	316,527
Federal income taxes	197,694	152,963	136,060
Taxes other than income	423,505	437,347	338,323
Total operating expenses	3,787,264	3,806,247	3,506,570
OPERATING INCOME	1,119,431	1,085,275	1,034,345
OTHER INCOME (LOSS)			
Allowance for equity funds used during construction	194,462	251,744	402,447
Provision for regulatory disallowances (Note 12)	—	(1,381,145)	—
Other income and deductions — net	7,882	12,462	4,687
Federal income taxes (Notes 8 and 12)	(2,479)	362,852	(1,435)
Total other income (loss)	199,865	(754,087)	405,699
TOTAL INCOME	1,319,296	331,188	1,440,044
INTEREST CHARGES			
Interest on mortgage bonds	598,235	608,729	551,986
Interest on other long-term debt	54,379	61,822	92,749
Other interest	36,202	62,111	46,604
Allowance for borrowed funds used during construction	(109,736)	(112,301)	(215,571)
Total interest charges	579,080	620,361	475,768
Income (loss) before cumulative effect of a change in accounting principle	740,216	(289,173)	964,276
Cumulative effect of a change in accounting for unbilled revenue (Net of taxes of $41,679,000)(Note 15)	80,907	—	—
NET INCOME (LOSS)	821,123	(289,173)	964,276
PREFERRED STOCK DIVIDENDS	118,418	121,603	118,268
NET INCOME (LOSS) AFTER PREFERRED STOCK DIVIDENDS	$ 702,705	$ (410,776)	$ 846,008

See accompanying Notes to Financial Statements.

TEXAS UTILITIES ELECTRIC COMPANY

STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	1992	1991	1990
		Thousands of Dollars	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 821,123	$ (289,173)	$ 964,276
Adjustments to reconcile net income (loss) to cash provided by operating activities:			
Depreciation	406,088	418,899	314,044
Deferred federal income taxes — net	177,097	(247,264)	27,464
Federal investment tax credits — net	(20,322)	(53,498)	33,841
Allowance for equity funds used during construction	(194,462)	(251,744)	(402,447)
Amortization of regulatory assets	13,941	17,540	11,087
Amortization of nuclear fuel	24,214	14,086	8,016
Provision for regulatory disallowances (Note 12)	—	1,381,145	—
Provision for refunds and related interest — net (Note 12)	(18,475)	44,893	—
Cumulative effect of a change in accounting for unbilled revenue – net (Note 15)	(80,907)	—	—
Cash flows from operations	1,128,297	1,034,884	956,281
Changes in assets and liabilities:			
Receivables — net	101,299	(29,854)	59,820
Inventories	(17,791)	(19,224)	(45,215)
Accounts payable — net	36,613	(17,095)	(39,429)
Interest and taxes accrued	1,514	84,021	16,608
Other working capital	54,372	42,999	(13,882)
Over/under-recovered fuel revenue	(42,203)	(43,529)	(53,704)
Deferred taxes on over/under-recovered fuel revenue	14,349	14,800	18,259
Voluntary retirement/severance program (See Note 13)	(90,905)	—	—
Other — net	(2,089)	21,105	45,044
Cash provided by operating activities	1,183,456	1,088,107	943,782
CASH FLOWS FROM FINANCING ACTIVITIES:			
Sales of securities:			
First mortgage bonds	1,808,595	737,298	590,790
Commercial paper	—	215,000	—
Preferred stock	—	—	98,625
Common stock	401,163	350,463	399,900
Retirement of long-term debt and preferred stock	(1,807,382)	(237,178)	(73,838)
Change in notes payable to parent	51,750	(134,000)	(240,750)
Change in notes payable to banks	—	—	35,000
Preferred stock dividends paid	(120,362)	(121,610)	(99,719)
Common stock dividends paid	(645,260)	(650,940)	(607,230)
Debt premium, discount and financing expenses	(125,009)	(22,298)	(8,283)
Cash provided by (used in) financing activities	(436,505)	136,735	94,495
CASH FLOWS FROM INVESTING ACTIVITIES:			
Construction expenditures	(1,107,555)	(1,195,680)	(1,4[illegible]1,647)
Allowance for equity funds used during construction (excluding amount for nuclear fuel)	179,519	232,068	97,289
Change in construction receivables/payables — net	(4,301)	(6,074)	(3,606)
Cash construction expenditures	(932,337)	(969,686)	(1,03[illegible],964)
Non-utility property — net	1,518	(27)	(6[illegible])
Nuclear fuel (excluding allowance for equity funds used during construction)	(33,656)	(16,694)	(2,180)
Other investments	(8,591)	(11,278)	1,454
Cash used in investing activities	(973,066)	(997,685)	(1,038,759)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(226,115)	227,157	(482)
CASH AND CASH EQUIVALENTS — BEGINNING BALANCE	231,801	4,644	5,126
CASH AND CASH EQUIVALENTS — ENDING BALANCE	$ 5,686	$ 231,801	$ 4,644

See accompanying Notes to Financial Statements.

TEXAS UTILITIES ELECTRIC COMPANY

BALANCE SHEETS

ASSETS

	December 31 1992	December 31 1991
	Thousands of Dollars	
ELECTRIC PLANT		
In service:		
Production	$10,490,214	$10,421,387
Transmission	1,493,602	1,443,565
Distribution	3,567,646	3,377,396
General	440,665	425,448
Total	15,992,127	15,667,796
Less accumulated depreciation	3,741,020	3,392,463
Electric plant in service less accumulated depreciation	12,251,107	12,275,333
Construction work in progress	5,528,222	4,809,088
Nuclear fuel (net of accumulated amortization — 1992, $49,606,000; 1991, $25,393,000)	358,087	333,701
Held for future use	29,639	29,069
Electric plant less accumulated depreciation and amortization	18,167,055	17,447,191
Less reserve for regulatory disallowances (Note 12)	1,308,460	1,308,460
Net electric plant	16,858,595	16,138,731
INVESTMENTS	35,993	28,919
CURRENT ASSETS		
Cash in banks	5,686	5,451
Temporary cash investments	–	226,350
Special deposits	7,510	22,171
Accounts receivable:		
Customers (Notes 10 and 15)	113,576	85,010
Other	30,289	39,840
Allowance for uncollectible accounts	(1,613)	(2,931)
Inventories — at average cost:		
Materials and supplies	187,301	174,977
Fuel stock	91,535	86,068
Prepaid taxes	9,778	10,771
Other current assets	17,693	22,953
Total current assets	461,755	670,660
DEFERRED DEBITS		
Unamortized regulatory assets:		
Debt reacquisition costs	214,245	109,708
Cancelled lignite unit costs	23,189	25,563
Rate case costs	52,006	48,328
Litigation and settlement costs	72,685	72,685
Voluntary retirement/severance program (Note 13)	204,881	–
Under-recovered fuel revenue	75,152	32,950
Other deferred debits	36,996	38,615
Total deferred debits	679,154	327,849
Less reserve for regulatory disallowances (Note 12)	72,685	72,685
Net deferred debits	606,469	255,164
Total	$17,962,812	$17,093,474

See accompanying Notes to Financial Statements.

TEXAS UTILITIES ELECTRIC COMPANY

BALANCE SHEETS

CAPITALIZATION AND LIABILITIES

	December 31, 1992	December 31, 1991
	Thousands of Dollars	
CAPITALIZATION		
Common stock without par value:		
Authorized shares — 180,000,000		
Outstanding shares — 1992, 148,600,000; 1991, 141,125,000	$ 4,717,625	$ 4,316,463
Retained earnings	1,480,583	1,424,974
Total common stock equity	6,198,208	5,741,437
Preferred stock:		
Not subject to mandatory redemption	909,564	1,007,728
Subject to mandatory redemption	418,748	425,758
Long-term debt, less amounts due currently	7,280,301	7,253,626
Total capitalization	14,806,821	14,428,549
CURRENT LIABILITIES		
Notes payable:		
Parent	51,750	—
Banks	250,000	250,000
Long-term debt due currently	164,054	82,522
Total (expected to be refinanced)	465,804	332,522
Accounts payable:		
Affiliates	138,586	109,288
Other	151,587	149,950
Dividends declared	27,795	30,225
Customers' deposits	52,640	52,159
Taxes accrued	257,384	251,363
Interest accrued	181,415	185,923
Other current liabilities	87,789	72,862
Total current liabilities	1,363,000	1,184,292
DEFERRED CREDITS AND OTHER NONCURRENT LIABILITIES		
Accumulated deferred federal income taxes	889,576	658,585
Unamortized federal investment tax credits	707,358	727,896
Other deferred credits and noncurrent liabilities	196,057	94,152
Total deferred credits and other noncurrent liabilities	1,792,991	1,480,633
COMMITMENTS AND CONTINGENCIES (Notes 2 and 14)	—	—
Total	$17,962,812	$17,093,474

See accompanying Notes to Financial Statements.

TEXAS UTILITIES ELECTRIC COMPANY

STATEMENTS OF RETAINED EARNINGS

	Year Ended December 31,		
	1992	1991	1990
	Thousands of Dollars		
BALANCE AT BEGINNING OF YEAR	$1,424,974	$2,486,690	$2,247,913
ADD — NET INCOME (LOSS)	821,123	(289,173)	964,276
Total	2,246,097	2,197,517	3,212,189
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)	1,784	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)	2,796	2,796	2,796
9.36 series ($ 9.36 per share per annum)	2,808	2,808	2,808
8.68 series ($ 8.68 per share per annum)	2,604	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)	2,496	2,496	2,496
8.84 series ($ 8.84 per share per annum)	2,652	2,652	2,652
9.48 series ($ 9.48 per share per annum)	8,944	9,236	9,236
8.92 series ($ 8.92 per share per annum)	4,460	4,460	4,460
10.00 series ($10.00 per share per annum)	4,900	5,000	5,000
10.92 series ($10.92 per share per annum)	3,276	3,276	3,276
10.12 series ($10.12 per share per annum)	3,542	3,542	3,542
10.08 series ($10.08 per share per annum)	2,999	3,140	3,278
11.32 series ($11.32 per share per annum)	3,396	3,396	3,396
9.64 series ($ 9.64 per share per annum)	9,640	9,640	9,640
10.375 series ($10.375 per share per annum)	7,781	7,781	5,793
9.875 series ($ 9.875 per share per annum)	2,469	2,468	555
Adjustable rate series A	6,500	6,500	6,613
Adjustable rate series B	5,950	6,014	6,162
Stated rate auction series A	6,180	8,240	8,240
Flexible adjustable rate series A	4,244	4,500	4,619
Flexible adjustable rate series B	4,244	4,500	4,619
Common stock (per share: 1992, $4.48; 1991, $4.80; 1990, $4.68)	645,260	650,940	607,230
Total cash dividends	763,288	772,136	725,162
Dividends other than cash — accretions	390	407	337
Total dividends	763,678	772,543	725,499
Preferred stock redemption costs	1,836	—	—
BALANCE AT END OF YEAR	$1,480,563	$1,424,974	$2,486,690

See accompanying Notes to Financial Statements.

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).

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. In 1990 and 1991, the Company used a net-of-tax rate of 9.0% and 10.4%, respectively, on projects commenced before March 1, 1986, and a gross rate of 10.5% and 12.0%, respectively, on projects commenced thereafter. The net and gross rates were changed for 1992 to 8.8% and 10.4%, respectively. 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 2.7%, 2.9% and 2.9% for 1992, 1991 and 1990, respectively. Depreciation also includes an amount for Comanche Peak nuclear generating station (Comanche Peak) decommissioning costs which is being accrued over the life of the unit and deposited to an external trust fund. (See Note 14.)

Amortization of Nuclear Fuel and Refueling Outage Costs — The amortization of nuclear fuel in the reactor (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 Unit 1 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 15). 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 cogenerators not included in base rates. The fuel portion of purchased power cost is included in the fixed fuel factor. Pursuant to a PUC rule, the Company is required to refund over-recovered fuel revenue if the amount of over-recovery, including interest, exceeds the lesser of $40 million or 4% of its annual known or reasonably predictable fuel costs most recently

1. SIGNIFICANT ACCOUNTING POLICIES — (concluded)

approved by the PUC. Reconciliation of fuel costs is to be made in a general rate case or a reconciliation proceeding. Reconciliation may be requested only if it has either been over one year since the utility's last final reconciliation or the utility has materially under-recovered its known or reasonably predictable fuel costs.

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 timing differences between book and taxable income (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. Cumulative timing differences in earlier years for which deferred federal income taxes were not provided approximated $194,000,000 at December 31, 1992. Investment tax credits are normally amortized to income over the estimated service lives of the properties. (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.

Supplemental schedules of cash payments and noncash investing and financing activities are provided below:

	Year End December 31,		
	1992	1991	1990
	Thousands of Dollars		
CASH PAYMENTS:			
Interest (net of amounts capitalized)	$556,762	$605,845	$458,528
Income taxes	37,714	70,325	59,390
NONCASH INVESTING AND FINANCING ACTIVITIES:			
Purchase of minority ownership interest in Comanche Peak:			
Production and transmission plant	$ —	$ —	$183,501
Nuclear fuel	—	—	13,709
Reimbursement of certain expenses (deferred debits) and working funds advances	—	—	32,695
Total purchase price	—	—	229,905
Plus financing charges	—	—	8,634
Less amounts due from minority owners	—	—	45,818
Less promissory note, obligation and debt assumed	—	—	174,721
Less payment made in prior period	—	—	18,000
Cash paid on the purchase	$ —	$ —	$ —

2. AFFILIATES

Texas Utilities 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 1992, 1991 and 1990 were approximately $118,407,000, $133,615,000, and $123,289,000, 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 1992, 1991 and 1990 were approximately $844,671,000, $860,462,000 and $884,059,000, respectively; and 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 1992, 1991 and 1990 were approximately $382,379,000, $368,470,000 and $364,285,000, respectively. Payments for interest on short-term financings from Texas Utilities for 1992, 1991 and 1990 were approximately $4,310,000, $3,512,000 and $18,427,000, 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, $359,160,000 at December 31, 1992, and interest on long-term notes of Fuel Company and of Mining Company through payments described above. Such notes mature at various dates through 2001 and have interest rates ranging from 8.50% to 10.85%.

3. SHORT-TERM FINANCING

At December 31, 1992, the Company and Texas Utilities have joint lines of credit aggregating $1,025,000,000 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 in May 1993, 1994 and 1995 by $325,000,000, $350,000,000 and $350,000,000, respectively. This credit facility may be used to finance new construction, as backup for commercial paper and for general corporate purposes. At December 31, 1992, $250,000,000 was outstanding under this credit facility. From time to time Texas Utilities makes short-term loans to the Company.

4. COMMON STOCK

The Company issued and sold shares of its authorized but unissued common stock to Texas Utilities as follows: December 1992, 3,600,000 shares for $201,600,000; March 1992, 3,875,000 shares for $199,562,500; December 1991, 3,950,000 shares for $200,463,000; June 1991, 3,125,000 shares for $150,000,000; May 1990, 8,600,000 shares for $399,900,000.

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. Preferred Stock (cumulative, without par value, entitled upon liquidation to $100 a share; authorized 17,000,000 shares)

Series Groups		Shares Outstanding December 31,		Amount December 31,		Redemption Price Per Share (Before Adding Accumulated Dividends)			
						Current		Eventual Minimum	
From	To	1992	1991	1992	1991	From	To	From	To
				Thousands of Dollars					
Not Subject to Mandatory Redemption									
$4.00	$ 4.84	1,142,942	1,142,942	$114,588	$ 114,588	$101.79	$112.00	$101.79	$112.00
5.08	7.80	1,629,675	1,629,675	163,270	163,270	102.40	103.60	102.40	103.60
8.16	8.92	1,999,475	1,999,475	198,642	198,642	101.92	104.09	101.00	103.60
9.32	11.32	1,550,000	1,550,000	153,205	153,205	102.33	107.55	100.00	102.73
Adjustable rate (a)		1,850,000	1,850,000	181,713	181,713	103.00	103.00	100.00	100.00
Stated rate auction (b)		—	1,000,000	—	98,164	—	—	—	—
Flexible adjustable rate (c)		1,000,000	1,000,000	98,146	98,146	—	—	100.00	100.00
Total		9,172,092	10,172,092	$909,564	$1,007,728				
Subject to Mandatory Redemption (d)(e)									
$8.92	$ 9.48	1,433,300	1,474,250	$142,802	$ 146,781	$102.00	$105.00	$100.00	$100.00
9.64	10.375	2,774,000	2,808,000	275,946	278,977	100.00	107.56	100.00	100.00
Total		4,207,300	4,282,250	$418,748	$ 425,758				

(a) Adjustable rate series A bears a dividend rate for the period ended January 31, 1993, of 6.50% per annum and adjustable rate series B bears a dividend rate for the period ended December 31, 1992, of 7.00% per annum, both of which are based on a fixed liquidation price of $100 per share.

(b) Stated rate auction series A was redeemed in September 1992.

(c) Flexible adjustable rate series A and B bear a dividend rate for the period ended December 31, 1992 of 8.05% per annum, based on a fixed liquidation price of $100 per share. The shares will continue to bear an adjustable dividend rate, based on the rates of certain U. S. Treasury securities, through June 30, 1993. During this initial period under certain circumstances relating to a change in federal tax law governing the dividends received deduction applicable to eligible corporations, the dividend rate may increase or decrease accordingly. In no case will the per annum dividend rate during this initial period be greater than 14% or less than 7%. After June 30, 1993, dividends will be determined on the basis of certain auction procedures. The shares are not redeemable before June 30, 1993, unless a change in the federal tax law governing the dividends received deduction occurs, at which time the shares may be redeemed on any quarterly dividend payment date through April 30, 1993.

(d) 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 occurring on the initial/next dates shown below, except for the $8.92 series which does not have a sinking fund provision. These redeemable shares may be called, purchased or otherwise acquired. Certain issues may not be redeemed prior to 1995. The Company may annually call for redemption, at its option, an aggregate of up to

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

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 of $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
$10.08	14,000 annually	4/1/93
9.48	66,700 annually	4/1/93
10.00	20,000 annually	7/1/93
9.64	125,000 semi-annually	5/1/95
10.375	150,000 annually	4/1/96
8.92	All outstanding shares	7/1/96
9.875	50,000 annually	10/1/96

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.

In 1992, the Company redeemed or otherwise acquired 14,000 shares of its $10.08 series, 20,000 shares of its $10.00 series and 40,950 shares of its $9.48 series cumulative preferred stock which fulfills its mandatory redemption requirements until April 1, 1993.

In the last three years, the Company issued and sold shares of its authorized preferred stock as follows: October 1990, 250,000 shares of $9.875 series, subject to mandatory redemption, for $24,531,250; April 1990, 750,000 shares of $10.375 series, subject to mandatory redemption, for $74,093,750. In January 1993, the Company issued and sold 5,000,000 depository shares each representing 1/4th of a share of $8.20 cumulative preferred stock for $121,062,500.

6. **RETAINED EARNINGS RESTRICTIONS**

The Company's articles of incorporation, the mortgages, as supplemented, and the debenture agreements contain provisions which, under certain conditions, restrict distributions on or acquisitions of its common stock. At December 31, 1992, $163,428,000 of retained earnings were thus restricted as a result of the provisions of such articles of incorporation.

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.

7. Long-Term Debt, less amounts due currently

Maturity Groups From	Maturity Groups To	Interest Rate Groups From	Interest Rate Groups To	December 31, 1992	December 31, 1991
				Thousands of Dollars	
First mortgage bonds:					
1993	1997	4-1/4%	9-1/2%	$ 474,000	$ 3[illegible]6,000
1998	2002	6-5/8	10-3/8	1,207,000	690,000
2003	2007	7-1/2	10-1/8	800,000	750,000
2008	2012	9-3/8	11-5/8	325,000	400,000
2015	2017	9-1/4	12	450,000	1,675,000
2018	2022	8-7/8	11-3/8	1,225,000	950,000
2023	2024	8-1/2	8-3/4	375,000	—
Pollution control series:					
2007	2027	6-1/2	10	1,136,595	990,000
Taxable pollution control series: (a)					
—	2021	Various		228,340	275,000
Sinking fund debentures:					
1993	1994	6-5/8	7-3/4	11,950	29,053
Secured medium-term notes, series A through C:					
1994	2003	8.72	10.50	600,000	600,000
Total				6,832,885	6,715,053
Pollution control revenue bonds:					
2004	2009	5.70	7-5/8	157,150	158,930
Promissory note, obligation and debt assumed for purchase of electric plant:(b)					
1993	2021	8.25	9.73	348,899	437,773
Unamortized premium and discount				(58,633)	(58,130)
Total long-term debt, less amounts due currently				$7,280,301	$7,253,626

(a) Taxable pollution control series consist of four series: $18,340,000 at 3.65% and $10,000,000 at 3.90% of flexible rate Series 1991A at December 31, 1992; $50,000,000 of Series 1991B at 8.10% through June 1, 1993; $50,000,000 of Series 1991C at 8.49% through June 1, 1994; and $100,000,000 of Series 1991D at 8.85% through June 1, 1995. Series 1991A 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 interest rates on Series 1991B through Series 1991D bonds will be repriced at various mandatory tender dates beginning in 1993. The Company has existing lines of credit that would allow refinancing of all the bonds 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. Also in 1988, the Company purchased the ownership interest in Comanche Peak of the Texas Municipal Power Agency under an installment sale agreement obligating the Company to make semi-annual payments through August 1993, which are included in long-term debt due currently at December 31, 1992. The transaction is treated as a completed purchase of electric plant; however, under terms of the agreement, legal title to the purchased assets passes to the Company at the time of, and in proportion to, each payment made. 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 1993 through 1997 under long-term debt instruments in effect at December 31, 1992, were as follows:

Year	Sinking Fund(a)	Maturity(b)	Minimum Cash Requirement(c)
	Thousands of Dollars		
1993	$64,996	$116,967	$164,054
1994	24,238	140,450	147,143
1995	24,288	80,000	87,153
1996	24,100	96,000	103,652
1997	23,860	399,800	407,888

(a) Excluding requirements satisfied prior to December 31, 1992: $1,422,500 for 1993.

(b) The maturity requirements do not include the mandatory tenders of the Company's taxable pollution control series, equal to $78,340,000 in 1993, $50,000,000 in 1994 and $100,000,000 in 1995, which are expected to be remarketed.

(c) Other requirements may be satisfied by certification of property additions at the rate of 167% of such requirements, except for sixteen issues at 100%.

From time to time, various principal amounts of first mortgage bonds have been redeemed by the Company prior to maturity. In 1992, the Company redeemed $1,570,000,000 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

The details of federal income taxes are as follows:

	Year Ended December 31,		
	1992	1991	1990
	Thousands of Dollars		
Charged (credited) to operating expenses:			
Current	$ 50,616	$ 80,751	$ 56,828
Deferred — net:			
Differences between depreciation methods and lives	185,246	222,766	155,587
Certain capitalized construction costs	5,189	2,706	4,601
Over/under-recovered fuel revenue	13,371	14,800	18,259
Early redemptions of long-term debt	35,543	3,364	(1,736)
Prepaid (accrued) pension cost	(4,891)	(3,858)	2,942
Unbilled revenues	(4,568)	277	(14,165)
Minority owners settlement	—	190	5,971
Alternative minimum tax	(46,714)	(64,784)	(80,162)
Investment tax credit carryforward	9,451	16,243	(37,171)
Amortization of tax rate differences	(2,093)	(20,336)	(10,083)
Provision for refunds and related interest — net	6,282	(15,541)	—
Prior year adjustments	1,428	(18,883)	(1,562)
Net operating loss carryforward	(60,554)	(46,595)	—
Voluntary retirement/severance costs	29,400	—	—
Other	310	(4,819)	2,910
Total	167,400	85,530	45,391
Investment tax credits — net	(20,322)	(13,318)	33,841
Total to operating expenses	197,694	152,963	136,060
Charged (credited) to other income:			
Current	(21,567)	(4,678)	1,102
Deferred — net:			
Provision for regulatory disallowances	—	(327,178)	—
Amortization of regulatory disallowances	22,883	8,787	—
Other	1,163	397	333
Total	24,046	(317,994)	333
Investment tax credits — regulatory disallowances	—	(40,180)	—
Total to other income	2,479	(362,852)	1,435
Charged to cumulative effect of a change in accounting for unbilled revenue — deferred	41,679	—	—
Total federal income taxes	$241,852	$(209,889)	$137,495

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,		
	1992	1991	1990
	Thousands of Dollars		
Federal income taxes at statutory rate of 34%	$361,411	$(169,681)	$374,602
Reductions in federal income taxes resulting from:			
Allowance for funds used during construction	98,221	118,603	207,702
Depletion allowance	22,014	21,104	24,975
Amortization of investment tax credits	20,322	20,401	16,647
Amortization of tax rate differences	2,093	20,336	10,083
Reversal of prior book/tax differences:			
Provision for regulatory disallowances	—	(142,412)	—
Investment tax credit — regulatory disallowances	—	40,180	—
Other	(24,159)	(23,278)	(11,816)
Prior year adjustments	949	(11,694)	389
Other	119	(3,032)	(10,873)
Total reductions	119,559	40,208	237,107
Total federal income taxes	$241,852	$(209,889)	$137,495
Effective tax rate	22.8%	42.1%	12.5%

The Company has net operating loss carryforwards of approximately $315 million that are available to offset future ordinary taxable income. Approximately $137 million of these loss carryforwards expire in 2006 and the remaining $178 million expire in 2007. In addition, the Company has approximately $34 million of general business credit carryforwards which expire in 2006 and $248 million of minimum tax credit carryforwards which are available to offset future taxes.

In February 1992, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes" (Statement 109), which is effective for fiscal years beginning after December 15, 1992. Statement 109, 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, initial application of Statement 109 in 1993 increased both total assets and liabilities by approximately $1.4 billion and the effect on net income is not considered material. Continuing application of Statement 109 is not expected to have a material effect on the Company's financial position or results of operations.

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 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. (See Note 13.)

The following table sets forth the plan's funded status and amount recognized in the Company's balance sheets:

	December 31,	
	1992	1991
	Thousands of Dollars	
Actuarial present value of accumulated benefits:		
Accumulated benefit obligation (including vested benefits of $512,658,000 for 1992 and $584,120,000 for 1991)	$(543,318)	$(622,537)
Projected benefit obligation for service rendered to date	$(641,734)	$(760,502)
Plan assets at fair value, primarily equity investments, government bonds and corporate bonds	660,776	995,740
Plan assets in excess of projected benefit obligation	19,042	235,238
Unrecognized net gain from past experience different from that assumed and effects of changes in assumptions	(158,456)	(241,433)
Prior service cost not yet recognized in net periodic pension expense	21,839	21,949
Unrecognized plan assets in excess of projected benefit obligation at initial application	(5,079)	(8,660)
Prepaid (accrued) pension cost	$(122,654)	$ 7,094

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

	1992	1991
Discount rate	8.50%	8.50%
Increase in compensation levels	4.70	5.30

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

	Year Ended December 31,		
	1992	1991	1990
	Thousands of Dollars		
Service cost — benefits earned during the period	$ 23,838	$ 23,860	$ 22,231
Interest cost on projected benefit obligation	61,573	58,118	53,048
Actual return on plan assets	(71,043)	(207,126)	13,628
Net amortization and deferral	(1,285)	136,494	(81,767)
Net periodic pension cost	13,083	11,346	7,140
Deferred termination cost	116,665	—	—
Total pension cost	$129,748	$ 11,346	$ 7,140

9. Retirement Plan and Other Postretirement Benefits — (concluded)

The assumed long-term rate of return on plan assets was 8.75% for 1992, 1991, and 1990.

In addition to the retirement plan, the Company offers certain health care and life insurance benefits to active and retired employees. The costs of such benefits are generally recognized as claims are paid. The costs of providing such benefits to retired employees, net of employee contributions, approximated $13,002,000 for 1992, $13,781,000 for 1991 and $12,342,000 for 1990.

In December 1990, FASB issued Statement of Financial Accounting Standards No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions" (Statement 106), which is effective for fiscal years beginning after December 15, 1992. Statement 106 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 unfunded actuarial present value of employee service rendered to the date of adoption (transition obligation at January 1, 1993) is approximately $300 million. Statement 106 allows the transition obligation to be either recognized immediately as the cumulative effect of a change in accounting principle or amortized evenly over the longer of the average remaining service lives of covered employees or 20 years. The Company intends to recognize the transition obligation over 20 years. The Company's total annual benefits cost under Statement 106, including amortization of the transition obligation over 20 years, is approximately $46 million.

In December 1992, the PUC issued a proposed rule that would allow a request for a one time conversion from the "pay-as-you-go" method for ratemaking purposes to a method allowing recovery of accrual costs as defined by the PUC rule. The proposed rule would exclude recovery of the transition obligation from net periodic postretirement benefit cost as defined by Statement 106. If the rule is approved as proposed, net income would be adversely affected by approximately $10 million annually. The proposed rule is expected to be finalized in the first quarter of 1993.

10. Sales of Accounts Receivable

In 1989, the Company entered into a five year agreement with certain financial institutions whereby the Company is entitled to sell and such financial institutions are required to purchase, on an ongoing basis, up to an aggregate of $300,000,000 of undivided interests in customer accounts receivable. Additional receivables are continually sold to replace those collected. At December 31, 1992 and 1991, $300,000,000 and $200,000,000, respectively, of such receivables were owned by financial institutions.

11. Comanche Peak Nuclear Generating Station

The Company is operating one nuclear-fueled generating unit and is finalizing construction on a second unit at Comanche Peak, each of which is designed for a capability of 1,150 megawatts. The Company owns all of the plant. (See Note 7.)

The Company is subject to the jurisdiction of the Nuclear Regulatory Commission (NRC) with respect to nuclear power plants. NRC regulations govern the granting of licenses for the construction and

11. COMANCHE PEAK NUCLEAR GENERATING STATION — (concluded)

operation of nuclear power plants and subject such plants to continuing review and regulation. In April 1990, the NRC issued a full power operating license for Unit 1. The construction permit for Unit 2 is in effect and has been extended until a "latest date of completion" of August 1, 1995. In February 1993, pursuant to a license issued by the NRC, the Company loaded fuel and commenced low power testing of Unit 2.

In August 1992, following the action by NRC staff which extended the construction permit for 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 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. The Company does not believe that any such proceeding will affect the licensing of Unit 2 for full power operation.

Unit 1 and common facilities were placed in commercial operation on August 13, 1990, and Unit 2 is scheduled for service for the peak season of 1993. At December 31, 1992, the Company had $4.22 billion invested in Unit 2 (net of $485 million included in the reserve for regulatory disallowances required by order of the PUC in Docket 9300), including AFUDC. The estimated cash requirements in 1993 to complete Unit 2 are approximately $82 million. AFUDC accruals for Unit 2, which approximated $30 million for the month of January 1993, will continue until the unit is in commercial operation. Also, in January 1993, pursuant to adopting a new accounting standard for income taxes which precludes net-of-tax accounting for income taxes, the Company increased previously recorded AFUDC by $219 million with a corresponding increase in deferred income taxes.

12. RATE PROCEEDINGS

On January 22, 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. Such request reflects, among other things, costs associated with the anticipated commercial operation of Comanche Peak Unit 2, costs associated with Comanche Peak Unit 1 capital investment after the end of the Docket 9300 test year (see below), additional ad valorem taxes and certain postretirement benefit costs. The proposed rate adjustments, if approved, would affect all classes of service and are estimated to increase annual operating revenues by approximately $760 million, or 15.3%, based upon the test year ended June 30, 1992. The Company is unable to predict the extent to which this rate increase request will be granted. The Company expects to place new rates in effect, under bond, when Unit 2 of Comanche Peak achieves commercial operation which is scheduled for the peak season of 1993. The request to place additional amounts of Comanche Peak investment in rate base will be subject to a review by the PUC for prudence of costs incurred. In connection with the September 1991 rate order in Docket 9300, the PUC reviewed costs incurred through June 1989 on Unit 2 and through fuel load in February 1990 on Unit 1. At December 31, 1992, the Company had approximately $2.6 billion invested in Comanche Peak that had not been reviewed for prudence. The Company cannot predict the outcome of any future prudence review. Accordingly, no provision for loss, if any, has been made in the financial statements of the Company. The Company is also seeking reconciliation, under the fuel rule currently in effect, of approximately $4.6 billion of fuel costs incurred during the three year period ended June 30, 1992.

12. Rate Proceedings — (continued)

In January 1990, the Company made applications to the PUC (Docket 9300) and to its municipal regulatory authorities for upward adjustments in rates for electric service throughout its service area which would increase operating revenues by approximately $442 million, or 10.2%, based upon the test year ended June 30, 1989. Such request reflected costs associated with the commercial operation of Unit 1 of Comanche Peak. On August 13, 1990, pursuant to rules of the PUC, the Company placed its requested rate increase into effect, under bond, applicable to energy sales on or after such date.

In September 1991, the PUC issued a final order in Docket 9300. The order 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 interests 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 addition, the order provided for refunds aggregating $56 million, including interest, principally with respect to fuel gas costs considered imprudent by the PUC. Such amount is being refunded to customers, with interest, over a two year period that began in November 1991.

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 order in Docket 9300. The charge is comprised of the $472 million of costs associated with Comanche Peak that were disallowed and the disallowance of $909 million related to the minority owner reacquisitions. Also, the Company recorded a charge of $56 million including interest ($37 million after tax), representing principally fuel gas costs disallowed by the 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 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. In the judgment, the Court affirmed the prudence disallowance of $472 million with regard to certain costs associated with Comanche Peak 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 concluded that upon remand the PUC must consider all factors relevant to the overall public interest, including all factors and considerations raised by the evidence presented by the Company, and should not base its decision solely on a "least-cost" comparison of generation alternatives in its determination of reasonable value in connection with these transactions. The Court also found that the PUC erred in ordering a refund of approximately $2.5 million with respect to certain fuel gas costs considered imprudent by the PUC. In addition, the Court indicated that the PUC erred in its calculation of the amount of the Company's cash working capital. 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 current rates approved in the PUC's final order.

12. RATE PROCEEDINGS — (concluded)

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. The disallowed Comanche Peak related costs are reflected as reserves for regulatory disallowances on the Company's balance sheet pending the outcome of any further appeals or reconsideration by the PUC.

In October 1992, the General Counsel's office of the PUC filed a complaint against the Company requesting that the PUC review certain aspects of the Company's implementation of bonded rates in Docket 9300 for the period during which such rates were in effect. The complaint alleges primarily that during such period the Company should not have accrued approximately $70 million of AFUDC related to the Unit 2 investment which was subsequently included as CWIP in rate base pursuant to the rate order in Docket 9300. The Company disagrees with the General Counsel's position and expects that the issue will be resolved during the pendency of, or in connection with, Docket 11735.

13. OPERATIONS REVIEW AND COST REDUCTION

In April 1992, the System Companies commenced a plan to better prepare the System Companies to operate in the rapidly changing business environment of the electric utility industry and to reduce costs. All aspects of the System Companies' operations were examined to identify opportunities for effective changes in business processes and operating practices. Implementation of resulting changes in processes and practices has begun and will extend beyond 1993.

Related to this plan, the System Companies announced on June 1, 1992 an offer of enhanced voluntary early retirement to approximately 3,700 of the System Companies' 15,200 employees. All other regular full-time employees were offered a voluntary severance program. The election period for this program ended on September 1, 1992, with separation dates occurring through November 1, 1992. A total of 4,499 employees (about 30%) accepted the voluntary early retirement/severance program. The number of employee acceptances was about equally divided between employees electing early retirement and those electing voluntary severance. In September 1992, the System Companies deferred the cost of this program and other related costs, which at December 31, 1992 was approximately $255 million. The Company has requested recovery of these costs in rates in Docket 11735 (see Note 12) over a three year period as an offset to reductions in operating costs from changes in business processes and operating practices, which will result in net annual savings of approximately $117 million. The voluntary retirement/severance program was funded through a combination of pension plan assets (approximately $355 million) and general funds (approximately $84 million) of the Company and will not materially affect the Company's financial position or results of operations. (See Note 9.)

14. COMMITMENTS AND CONTINGENCIES

Cor uction Program

Construction expenditures, excluding AFUDC, for the years 1993 through 1995 are estimated at $580,000,000, $560,000,000 and $79( ),000, respectively. The effects of inflation, additional regulatory requirements, revisions in the expectea demand growth or other unknown factors could affect estimated completion costs and in service dates of generating units under construction. Commitments in connection with the construction program are generally revocable subject to reimbursement to manufacturers for expenditures incurred or other cancellation penalties.

Clean Air Act

In November 1990, the federal Clean Air Act Amendments of 1990 (Clean Air Act) were enacted which, among other things, placed limits on the sulfur dioxide emissions produced by generating units. The Clean Air Act requires that fossil-fueled plants meet new sulphur 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 Phase II requirements are currently met by all but four of the Company's generating units. Because the sulfur dioxide emissions from these four units are relatively low and alternatives are available to enable these units to reduce sulphur dioxide emissions, or utilize compensatory additional 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.

On January 11, 1993, the Environmental Protection Agency (EPA) issued its "core" regulations to implement the sulfur dioxide reduction program. The Company is reviewing these regulations and is preparing a compliance plan in accordance with the regulations. The Company intends to utilize internal allocation of emission allowances within its system and, if 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 currently required nitrogen oxide limits in 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 by 1996. 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 and such installation has begun.

14. COMMITMENTS AND CONTINGENCIES — (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 of compliance with the major requirements. The Company believes that it can meet the requirements necessary to be in compliance with these provisions as they are developed. Capital requirements related to the Clean Air Act are included in the Company's construction program. Any additional capital costs, as well as any increased operating costs associated with new requirements or compliance measures, are expected to be recovered through rates, as similar costs have been recovered in the past.

Energy Policy Act

The National Energy Policy Act of 1992 (Energy Act) was enacted in October 1992. The Energy Act seeks to increase competition in electric generation and increase access to electric transmission systems. The Energy Act addresses a wide range of energy issues, including several matters affecting bulk power competition in the electric utility industry, nuclear licensing reform, nuclear plant decommissioning and energy efficiency. This legislation includes changes to the Public Utility Holding Company Act of 1935, the Public Utility Regulatory Policies Act of 1978 and the Federal Power Act. The Company is unable to predict the impact of this legislation on its operations.

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, 1992, 1991 and 1990 were $240,342,000, $229,953,000 and $226,083,000, respectively.

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

Years	Total Thousands of Dollars
1993	$ 249,109
1994	244,799
1995	238,513
1996	228,337
1997	237,014
Thereafter	899,436
Total	$2,097,208

14. COMMITMENTS AND CONTINGENCIES — (continued)

Leases

The Company has entered into operating leases covering various facilities and properties including combustion turbines, transportation, data processing equipment and office space. Lease costs charged to operation expense for the years ended December 31, 1992, 1991 and 1990 were $66,219,000, $60,085,000 and $51,783,000, respectively.

The Company's future minimum lease commitments under such operating leases that have initial or remaining noncancelable lease terms in excess of one year as of December 31, 1992, were as follows:

Years	Combustion Turbines	Other	Total
	Thousands of Dollars		
1993	$ 28,347	$ 9,451	$ 37,798
1994	28,345	7,569	35,914
1995	28,345	3,670	32,015
1996	28,627	2,482	31,109
1997	35,808	1,738	37,546
Thereafter	661,395	7,141	668,536
Total minimum lease commitments	$810,867	$32,051	$842,918

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, $40,410,000 at December 31, 1992, 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 1993 through 1997 as follows: $4,422,000 for 1993, $4,423,000 for 1994, $4,431,000 for 1995, $4,430,000 for 1996 and $4,435,000 for 1997. Payments made by the Company, net of amounts assumed by a third party under such contracts, for 1992, 1991 and 1990 were $2,849,000, $2,596,000 and $3,437,000, 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 $90,455,000 remaining principal amount of bonds at December 31, 1992, 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), as most recently amended in 1988 to extend its effectiveness through 2002, was enacted by Congress to provide 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 $7.9 billion and requires nuclear power plant operators to provide financial protection for this amount. As required, the Company provides this financial

14. COMMITMENTS AND CONTINGENCIES — (continued)

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 retrospective 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 $66.15 million, subject to increases for inflation every five years, in the event of a nuclear incident at any nuclear plant in the United States. The $66.15 million assessment will increase to approximately $80 million in 1993. Assessments are limited to $10 million per operating licensed reactor per year per incident.

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 $2.625 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 $800 million and Nuclear Electric Insurance Limited (NEIL), a nuclear electric utility industry mutual insurance company, in the amount of $1.325 billion. The Company is subject to a maximum annual assessment from NEIL of $15 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.

In conjunction with commercial operation of Comanche Peak Unit 1, the Company began maintaining Extra Expense Insurance through NEIL to cover the additional costs of obtaining replacement power from another source if Comanche Peak Unit 1 is 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. Under this coverage, the Company is subject to a maximum assessment of $5 million per year. Similar coverage will be obtained for Comanche Peak Unit 2 when it achieves commercial operation.

Nuclear Decommissioning and Disposal of Spent Fuel

The Company has established a reserve (included in accumulated depreciation) for the decommissioning of Comanche Peak Unit 1, whereby decommissioning costs are being recovered from customers over the life of the plant and deposited to an external trust fund (included in other investments). As of December 31, 1992, $21,971,000 has been deposited to the external trust fund for decommissioning. 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 were estimated to be $255,000,000 and $344,000,000, respectively. Recovery of such costs began in August 1990, when

14. COMMITMENTS AND CONTINGENCIES — (concluded)

Comanche Peak Unit 1 began commercial operation. A request for recovery of costs for the revised estimate of Comanche Peak Unit 1 and for recovery of these costs for Comanche Peak Unit 2 was included in Docket 11735. (See Note 12.)

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 Unit 1 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 operations.

15. 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,		
	1992	1991	1990
	Thousands of Dollars		
As previously reported:			
Net income (loss)	$821,123	$(289,173)	$964,276
Pro forma:			
Net income (loss)	740,216	(286,457)	978,772

16. 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 is provided in compliance with Statement 107 and represents management's best 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 those instruments. The fair value of financial instruments for which estimated fair value has not been specifically presented is not materially different than the related book value.

16. Fair Value of Financial Instruments — (concluded)

Other investments include amounts principally for nuclear decommissioning fund assets and funds invested pursuant to certain incentive and compensation agreements. The fair value 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 value 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.

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, approximate fair value because of the short maturity of those instruments. Customer deposits have no defined maturities and 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, 1992 of the bonds for which the Company is contingently liable is $131,000,000, which approximates fair value. The fair value of the bonds is estimated 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 $359,160,000 at December 31, 1992. The fair value of such notes is approximately $390,423,000 which 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:

	1992	
	Carrying Amount	Fair Value
	Thousands of Dollars	
Long-term debt	$7,280,301	$7,976,303
Preferred stock subject to mandatory redemption	418,748	445,009
Other investments	31,620	32,623

17. 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, discussed in Note 15 to Financial Statements) 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,

17. Supplementary Financial Information (Unaudited) — (concluded)

variations in maintenance and other operating expense patterns, the impact of the change in AFUDC accruals (see Note 1) and, in the third quarter of 1991, the charge for provision for regulatory disallowances. (For additional information regarding the charge for provision for regulatory disallowance, see Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 12.)

Quarter Ended	Operating Revenues 1992	Operating Revenues 1991	Operating Income 1992	Operating Income 1991	Net Income (Loss) 1992	Net Income (Loss) 1991
	Thousands of Dollars					
March 31	$1,056,920	$1,094,003	$ 218,249	$ 242,004	$196,907	$ 151,986
June 30	1,195,775	1,197,059	281,853	274,495	187,757	177,939
September 30	1,478,148	1,449,331	410,248	358,889	325,488	(728,314)
December 31	1,175,852	1,151,129	209,081	209,887	110,971	109,216
	$4,906,695	$4,891,522	$1,119,431	$1,085,275	$821,123	$(289,173)

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, 1992, 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

INDEPENDENT AUDITORS' REPORT

Texas Utilities Electric Company:

We have audited the balance sheets of Texas Utilities Electric Company as of December 31, 1992 and 1991, and the related statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1992. 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, the financial statements referred to above present fairly, in all material respects, the financial position of the Company at December 31, 1992 and 1991, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1992, in conformity with generally accepted accounting principles. Also, in our opinion, the 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 Note 15 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 4, 1993

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 15, 1993)	Date First Elected as Director	Present Principal Occupation or Employment and Principal Business (preceding 5 yrs.), Other Directorships
T. L. Baker	47	Executive Vice President	February 20, 1987	Executive Vice President of the Company; prior thereto, Senior Vice President of the Company.
J. S. Farrington	58	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	55	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; prior thereto, Treasurer and Assistant Secretary of the Company.
Erle Nye	55	Chairman and Chief Executive	September 17, 1982	President of Texas Utilities; prior thereto, Executive Vice President of the Company and Executive Vice President of Texas Utilities; other directorships: Texas Utilities.
Michael D. Spence	51	Executive Vice President	September 17, 1982	Executive Vice President of the Company; prior thereto, President of Generating Division.
W. M. Taylor	50	Executive Vice President	May 20, 1986	Executive Vice President of the Company; prior thereto, President of Dallas Power Division.
E. L. Watson	58	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 15, 1993)	Date First Elected to Present Offices	Business Experience (Preceding Five Years)
Erle Nye	55	Chairman and Chief Executive	February 20, 1987	Same and President of Texas Utilities
T. L. Baker	47	Executive Vice President	October 1, 1991	Senior Vice President of the Company.
H. Jarrell Gibbs	55	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; prior thereto, Treasurer and Assistant Secretary of the Company.
Michael D. Spence	51	Executive Vice President	October 1, 1991	President of Generating Division.
W. M. Taylor	50	Executive Vice President	October 1, 1991	President of Dallas Power Division.
E. L. Watson	58	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. EXECUTIVE 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

Name and Principal Position	Year	Annual Compensation Salary ($)	Annual Compensation Bonus ($)	All Other Compensation ($)[2]
Erle Nye, Chairman of the Board and Chief Executive of the Company[1]	1992	525,000	0	622,941
	1991	493,750	0	NA
	1990	418,750	100,000	NA
Michael D. Spence, Executive Vice President of Company	1992	285,000	0	321,160
	1991	285,000	40,000	NA
	1990	285,000	75,000	NA
T. L. Baker, Executive Vice President of Company	1992	233,000	0	243,573
	1991	223,417	0	NA
	1990	202,500	0	NA
E. L. Watson, Vice Chairman of Company	1992	220,000	0	240,717
	1991	213,333	0	NA
	1990	199,000	0	NA
W. M. Taylor, Executive Vice President of Company	1992	205,000	0	221,719
	1991	198,750	0	NA
	1990	186,667	0	NA

(1) Amounts reported in the table consist entirely of compensation paid by Texas Utilities.
(2) Amounts reported as "All Other Compensation" represent amounts attributable to participation in certain benefit plans as 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 1990 and 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 above 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 1992, these employer contributions for Messrs. Nye, Spence, Baker, Watson and Taylor amounted to $8,239, $0, $1,812, $6,1[illegible]6 and $4,595, respectively.

Under the Deferred and Incentive Compensation Plan of the Texas Utilities Company System, 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. Such deferred compensation is included in amounts reported under "Salary" in the table above. 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. Such matching and incentive awards are subject to forfeiture under certain circumstances. During 1992, these matching and incentive awards for Messrs. Nye, Spence, Baker, Watson and Taylor amounted to $194,500, $66,300, $56,940, $54,600 and $66,900, respectively and are included above. 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. Incentive awards and earnings thereon maturing in 1992 were distributed to Messrs. Nye, Spence, Baker, Watson and Taylor in the amounts of $80,040, $48,024, $24,012, $24,012 and $16,008, respectively and are included above. During 1992, the Board of Directors of Texas Utilities amended the Plan to waive the maturity requirement and accelerate the distribution of deferred amounts, matching awards and related earnings which would otherwise have been payable in 1994 and 1996. These distributions of matching awards and earnings for Messrs. Nye, Spence, Baker, Watson and Taylor were $287,662, $184,036, $137,509, $133,959 and $126,016, respectively and are included above.

Texas Utilities has established a Salary Deferral Program effective April 1, 1991 under which each employee of the Company whose annual salary is $80,000 ($82,480 for the Plan Year beginning April 1992) 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 table above. 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 1992, matching awards, which are included above, were made for Messrs. Nye, Spence, Baker, Watson and Taylor in the amounts of $52,500, $22,800, $23,300, $22,000 and $8,200, respectively.

Item 11. EXECUTIVE COMPENSATION (Continued).

The Company maintains a retirement plan qualified under applicable provisions of the Internal Revenue Code (Code) for all employees who have reached the age of 21 and with at least one year of full time service with the Company. 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 as salary for specified officers 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 January 31, 1993, years of accredited service under the plans for Messrs. Nye, Spence, Baker, Watson and Taylor were 30, 26, 22, 33 and 24, respectively. The table illustrates the total annual benefit payable at retirement under these retirement plans.

3-Year Average Annual Earnings	20 Years Service	30 Years Service	40 Years Service
$ 50,000	$ 14,688	$ 22,032	$ 29,376
100,000	29,688	44,532	59,376
200,000	59,688	89,532	119,376
400,000	119,588	179,532	239,376
500,000	149,688	224,532	299,376
600,000	179,688	269,532	359,376
800,000	239,688	359,532	479,376

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, 1993.

ORGANIZATION AND COMPENSATION COMMITTEE REPORT

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 as identified on pages 2 and 3 of this proxy statement and is chaired by James K. Dobev. The Committee has directed the preparation of this report and has approved its contents and its submission to the shareholders. As provided by the rules of the Securities and Exchange Commission (Commission), this report is not to be considered to be filed with the Commission nor incorporated by reference in any Commission filings.

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 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. 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 opinion of the Committee, generally should be determined based upon the performance of the Company and the contributions of individual officers to such performance 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 the attainment of 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.

The compensation of the officers of the Company consists primarily of base salaries and the opportunity to participate in the Deferred and Incentive Compensation Plan (Plan) which is discussed later in this report. 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 6 and 7 of this proxy statement. The officers also participate in the Retirement Plan, the benefits payable under which are described on page 8 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.

During 1992, with management's recommendation, the base salaries of the executive officers, including the chief executive, were not increased. The recommendation of management and the approval of the Committee in this regard was based upon several factors, including the Company-wide efforts to reduce costs in order to mitigate partially the loss arising out of the TU Electric rate case. Incentive awards under the Deferred and Incentive Compensation Plan for the named executive officers, including the chief executive, were increased by a total of 11 percent over the prior year. As previously described, such awards are represented by common stock equivalents and the value of the future payment thereof is directly related to the future performance of the Company's common stock.

In establishing levels of executive compensation, the Committee regularly reviews Company performance and officers' compensation compared to the performance of similar businesses and the compensation levels of the executive management of such businesses. With respect to Company performance, TU Electric, the Company's principal subsidiary, in 1991 was the largest electric utility in the United States as measured by megawatt hour sales. Other 1991 comparisons to the largest utilities included electric revenues (6th), total assets (3rd), net generating capability (3rd), number of customers (6th) and number of employees (10th). The Committee also reviews a variety of industry financial and operating performance comparisons (including, for example, 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 has not, however, adopted or approved a specific formula directly linking any performance measure, or the aggregate of all measures, to the levels of executive compensation.

The Committee also reviews the compensation of the Company's officers compared to persons with comparable responsibilities in similar businesses as well as business in general. In that regard, information is gathered from industry sources and other published materials. Data for 1991, which was reviewed by the Committee in May 1992, indicated that the total compensation of the executive officers of the Company, including the chief executive, ranked at or below the middle of most comparisons. The Committee carefully reviews relevant compensation comparisons, but has not established a specific objective or target for the compensation of the Company's executive officers as compared to the compensation paid by other companies.

The Company has retained the services of an independent compensation consultant for a number of years. This consultant has provided a methodology under which professional and managerial jobs are evaluated and the compensation of the named executive officers is within the ranges established for those positions.

As previously noted, the Deferred and Incentive Compensation Plan (Plan) is administered by the Committee. The principal provisions of the Plan are described on pages 6 and 7 of this proxy statement. At its November 1992 meeting, the Committee approved an amendment to the Plan to allow the payment in 1992 of the value of the deferred amounts and matching awards which would otherwise have been payable in 1994 and 1996. The acceleration of these payments was authorized to more immediately recognize the participants' significant contributions to the redirection of the Company's business and in light of the fact that the base salaries of the named executive officers were not increased in 1992. Such acceleration did not result in any additional cost to the Company and may have allowed the officers to retain a larger percentage of the distributions after the payment of personal income taxes.

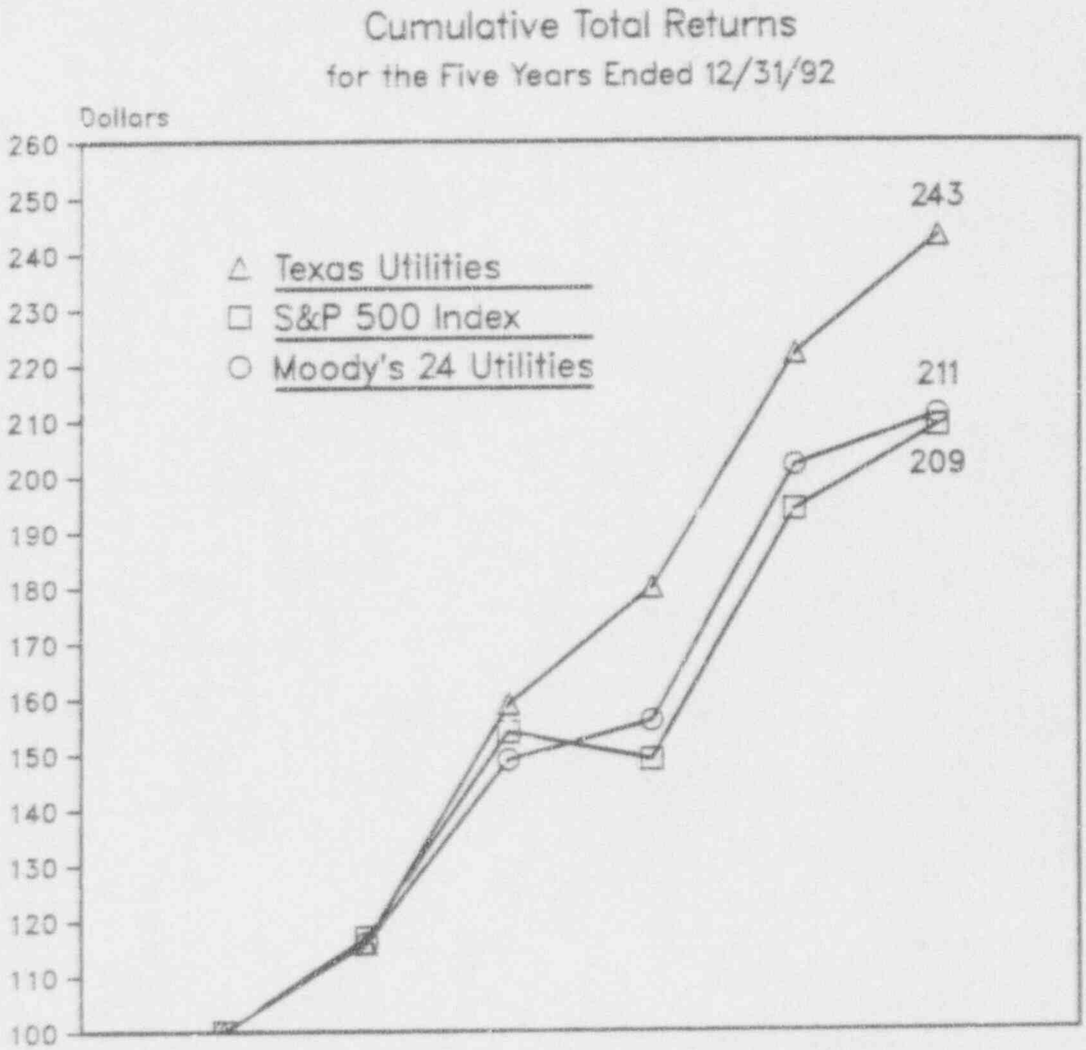
Shareholder comments to the Committee are welcomed and should be addressed to the Corporate Secretary of the Company at the Company's offices.

Item 11. (Concluded).

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 graph compares the performance of Texas Utilities 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, 1987 and that all dividends were reinvested.



	1987	1988	1989	1990	1991	1992
Texas Utilities ($)	100	116	159	180	222	243
S&P 500 Index ($)	100	117	154	149	194	209
Moody's 24 Utilities ($)	100	116	149	156	202	211

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT.

Security ownership of certain beneficial owners at January 31, 1993:

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	148,600,000 shares sole voting and investment power	100.0%

Security ownership of management at January 31, 1993:

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 any of the preferred stock of the Company.

Name	Number of Shares of Common Stock
T. L. Baker	1,804
J. S. Farrington	14,819
H. Jarrell Gibbs	3,610
Erle Nye	13,343
Micheal D. Spence	5,269
W. M. Taylor	5,590
E. L. Watson	4,577
All Directors and Executive Officers as a group (7)	49,012

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, 1992, are as follows:

Date of Report	Items Reported
October 28, 1992	Item 7. FINANCIAL STATEMENTS AND EXHIBITS
December 3, 1992	Item 5. OTHER EVENTS
January 12, 1993	Item 7. FINANCIAL STATEMENTS AND EXHIBITS
January 26, 1993	Item 5. OTHER EVENTS
February 23, 1993	Item 5. OTHER EVENTS

(c) Exhibits:

Exhibits	Previously Filed* With File Number	Previously Filed* As Exhibit		Number	Dated
3(a)	2-91002	4(a)	—	Articles of Incorporation of the Company.	
3(a)-1	33-52452	4(a)-2	—	Articles of Amendment of the Company, as corrected.	
3(a)-2	2-91002	4(b)-1	—	Statement of Resolution establishing Thirty-third Series of Preferred Stock of the Company.	

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

	Previously Filed*				
Exhibits	With File Number	As Exhibit		Number	Dated
3(a)-3	2-97786	4(b)-2	—	Statement of Resolution establishing Thirty-fourth Series of Preferred Stock of the Company.	
3(a)-4	33-5528	4(b)-3	—	Statement of Resolution establishing Thirty-fifth Series of Preferred Stock of the Company.	
3(a)-5	33-14585	4(b)-4	—	Statement of Resolution establishing Thirty-sixth Series of Preferred Stock of the Company.	
3(a)-6	33-14585	4(b)-5	—	Statement of Resolution establishing Thirty-seventh Series of Preferred Stock of the Company.	
3(a)-7	33-33432	4(b)-6	—	Statement of Resolution establishing Thirty-eighth Series of Preferred Stock of the Company.	
3(a)-8	33-33432	4(b)-7	—	Statement of Resolution establishing Thirty-ninth Series of Preferred Stock of the Company.	
3(a)-9	33-33432	4(b)-8	—	Statement of Resolution establishing Fortieth and Forty-first Series of Preferred Stock of the Company.	
3(a)-10	33-52452	4(b)-9	—	Statement of Resolution establishing Forty-second Series of Preferred Stock of the Company.	
3(a)-11	33-52452	4(b)-10	—	Statement of Resolution establishing Forty-third Series of Preferred Stock of the Company.	
3(a)-12			—	Statement of Resolution establishing Forty-fourth Series of Preferred Stock of the Company.	
3(b)			—	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 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

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

	Previously Filed*				
Exhibits	With File Number	As Exhibit		Number	Dated
	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
	33-49170	4(a)-3		Thirty-sixth	June 1, 1992
	33-49170	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
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

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

Exhibits	Previously Filed* With File Number	As Exhibit		Number	Dated
	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
	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

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

	Previously Filed*				
Exhibits	With File Number	As Exhibit		Number	Dated
	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
	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
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

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

	Previously Filed*			
Exhibits	With File Number	As Exhibit	Number	Dated
	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
	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-nineth	April 1, 1992
	33-57576	4(d)-1	Fiftieth	August 1, 1992
	33-57576	4(d)-2	Fifty-first	December 1, 1992
4(c)	2-28016	2(b)-13	— Debenture Agreement, dated as of February 1, 1968, between Dallas Power & Light Company and Morgan Guaranty Trust Company of New York, Trustee.	

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

Exhibits	Previously Filed* With File Number	As Exhibit		Number	Dated
4(e)-1	0-11442 Form 10-K (1983)	4(c)-3	—	First Supplemental Agreement, dated as of June 21, 1983, to the Debenture Agreement dated as of February 1, 1968, between Dallas Power & Light Company and Morgan Guaranty Trust Company of New York, Trustee.	
4(e)-2	0-11442 Form 10-K (1983)	4(c)-4	—	Second Supplemental Agreement, dated as of January 1, 1984, to the Debenture Agreement dated as of February 1, 1968, between TU Electric and Morgan Guaranty Trust Company of New York, Trustee.	
4(f)	2-27908	2(d)	—	Debenture Agreement, dated as of February 1, 1968, between Texas Electric Service Company and The First National Bank of Fort Worth, Trustee (Bank One, Texas, N.A. successor Trustee).	
4(f)-1	0-11442	4(d)-3	—	First Supplemental Agreement, dated as of June 29, 1983, to the Debenture Agreement dated as of February 1, 1968, between Texas Electric Service Company and the First National Bank of Fort Worth, Trustee (Bank One, Texas, N.A. successor Trustee).	
4(f)-2	0-11442 Form 10-K of(1983)	4(d)-4	—	Second Supplemental Agreement, dated as of January 1, 1984, to the Debenture Agreement dated as February 1, 1968, between TU Electric and InterFirst Bank Fort Worth, N.A., Trustee (Bank One, Texas, N.A., successor Trustee).	
4(g)	2-31966	4(c)	—	Debenture Agreement, dated as of April 1, 1969, between Texas Power & Light Company and First National Bank of Dallas, Trustee (NationsBank of Texas, N.A., successor Trustee).	
4(g)-1	..-11442 Form 10-K (1983)	4(e)-5	—	First Supplemental Agreement, dated as of June 28, 1983, to the Debenture Agreement dated as of April 1, 1969, between Texas Power & Light Company and InterFirst Bank Dallas, National Association, Trustee (NationsBank of Texas, N.A., successor Trustee).	
4(g)-2	0-11442 Form 10-K (1983)	4(e)-6	—	Second Supplemental Agreement, dated as of January 1, 1984, to the Debenture Agreement dated April 1, 1969, between TU Electric and InterFirst Bank Dallas, National Association, Trustee (NationsBank of Texas, N.A., successor Trustee).	
4(h)			—	Agreement to furnish certain debt instruments.	
4(i)			—	Deposit Agreement between the Company and Chemical Bank, dated January 19, 1993.	

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

Exhibits	Previously Filed* With File Number	As Exhibit		
			Number	Dated
10(a) **			—	Deferred and Incentive Compensation Plan of the Texas Utilities Company System, as amended June 30, 1992.
10(b) **			—	Salary Deferral Program of the Texas Utilities Company System, as amended May 31, 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.
24(a)			—	Consent of Counsel.
24(b)			—	Independent Auditors' Consent.
28(a)	0-11442 Form 10-K (1987)	28(b)	—	Agreement, dated as of February 12, 1988, between TU Electric and Texas Municipal Power Agency.
28(b)	0-11442 Form 10-Q (Quarter Ended June 30, 1988)	28(c)	—	Agreement, dated as of July 5, 1988, between the Company and the Brazos Electric Power Cooperative, Inc.
28(c)	0-11442 Form 10-K (1989)	28(d)	—	Agreement, dated as of February 1, 1990, between TU Electric and Tex-La Electric Cooperative, Inc.
28(d)	0-11442 Form 10-K (1990)		—	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.

*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, 1992

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, 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
Year Ended December 31, 1990					
Electric plant					
In service:					
Production	$ 3,121,363	$ 7,237,355	$16,602	$ —	$10,342,116
Transmission	1,321,739	68,528	2,852	1,544 (c)	1,388,959
Distribution	3,040,114	185,134	34,990	—	3,190,258
General	390,718	24,235	6,659	—	408,294
Total	7,873,934	7,515,252	61,103	1,544	15,329,627
Construction work in progress	9,915,896	(6,085,612)	—	181,957 (c)	4,012,241
Nuclear fuel — net	301,676	7,338	—	2,402 (c)(d)	311,416
Held for future use	25,252	3,737	—	—	28,989
Total electric plant	$18,116,758	$ 1,440,715	$61,103	$ 185,903	$19,682,273

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

(b) Disallowed Comanche Peak re' ed costs. (See Note 12 to Financial Statements.)

(c) Purchase of minority ownershi, .nterests in Comanche Peak. (See Note 1 to Financial Statements.)

(d) Other changes to nuclear fuel include $13,709,000 added upon purchase from Tex-La and $11,307,000 deducted for amortization.

TEXAS UTILITIES ELECTRIC COMPANY

SCHEDULE VI — ACCUMULATED DEPRECIATION

For Each of the Three Years in the Period Ended December 31, 1992

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, 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
Year Ended December 31, 1990					
Accumulated depreciation	$2,762,101	$314,044	$57,606	$8,456	$3,026,995

(a) Includes depreciation on lignite fuel production facilities charged to fuel and beginning in 1990 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, 1992

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, 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
Year ended December 31, 1990					
Allowance for uncollectible accounts	$ 3,141	$ 13,670	$ —	$14,521	$ 2,290

(a) Deductions from the allowance represent uncollectible accounts written off, less 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, 1992

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, 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
Year Ended December 31, 1990					
Amounts payable to banks for borrowings (b)	$ 35,000	10.00%	$ 35,000	$ 97	9.86%
Holders of commercial paper	—	—	305,235	86,914	8.53

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

(b) Bank loan is at a rate at all times equal to the prime commercial lending rate; such loan was repaid on January 2, 1991.

TEXAS UTILITIES ELECTRIC COMPANY

SCHEDULE X — SUPPLEMENTARY INFORMATION

For Each of the Three Years in the Period Ended December 31, 1992

COLUMN A	COLUMN B		
	Charged to Expenses and Other Accounts		
	Year Ended December 31,		
Item	1992	1991	1990
	Thousands of Dollars		
Taxes other than income:			
Ad valorem	$189,411	$176,414	$113,320
Local gross receipts	126,849	122,683	112,787
State gross receipts	72,345	71,512	64,570
State franchise	20,252	49,182	31,481
Social security and unemployment	41,356	38,170	36,938
Public Utility Commission assessment	7,613	7,664	7,011
Miscellaneous	22,143	18,821	16,146
Total	$479,969	$484,446	$382,253
Charged to:			
Operating expenses	$423,505	$437,347	$338,323
Electric plant and sundry accounts	56,464	47,099	43,930

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 4, 1993

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	
/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	March 4, 1993
/s/ MICHAEL D. SPENCE (Michael D. Spence)	Director	
/s/ W. M. TAYLOR (W. M. Taylor)	Director	
/s/ E. L. WATSON (E. L. Watson)	Director	