GULF STATES UTILITIES COMPANY

RIVER BEND STATION POST OFFICE BOX 220 ST. FRANCISVILLE, LOUISIANA 70775

AREA CODE 504 635-6094 346-8651

May 25, 1993
RBG- 38541
File No. G9.5

U.S. Nuclear Regulatory Commission
Document Control Desk
Washington, D.C. 20555

Gentlemen:

River Bend Station - Unit 1
Docket No. 50-458

Enclosed are ten (10) copies of the Gulf States Utilities Company 1992 Annual Report. This report is being submitted in accordance with Section 50.71 of Title 10 of the Code of Federal Regulations and U.S. NRC Regulatory Guide 10.1. The Cajun Electric Power Cooperative Annual Report is not available at this time; however, it will be sent as soon as it becomes available.

If you have any questions or comments, please contact Mr. Leif L. Dietrich of my staff at (504) 381-4866.

Sincerely,

J. E. Booker

J.E. Booker
Manager - Safety Assessment
and Quality Verification

LAE/LLD/JCM/kvm

Enclosures

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cc: U.S. Nuclear Regulatory Commission
611 Ryan Plaza Drive, Suite 400
Arlington, TX 76011

NRC Resident Inspector
P.O. Box 1051
St. Francisville, LA 70775

Mr. E. T. Baker
M/S OWFN 13-H-15
U.S. Nuclear Regulatory Commission
11555 Rockville Pike
Rockville, MD 20852

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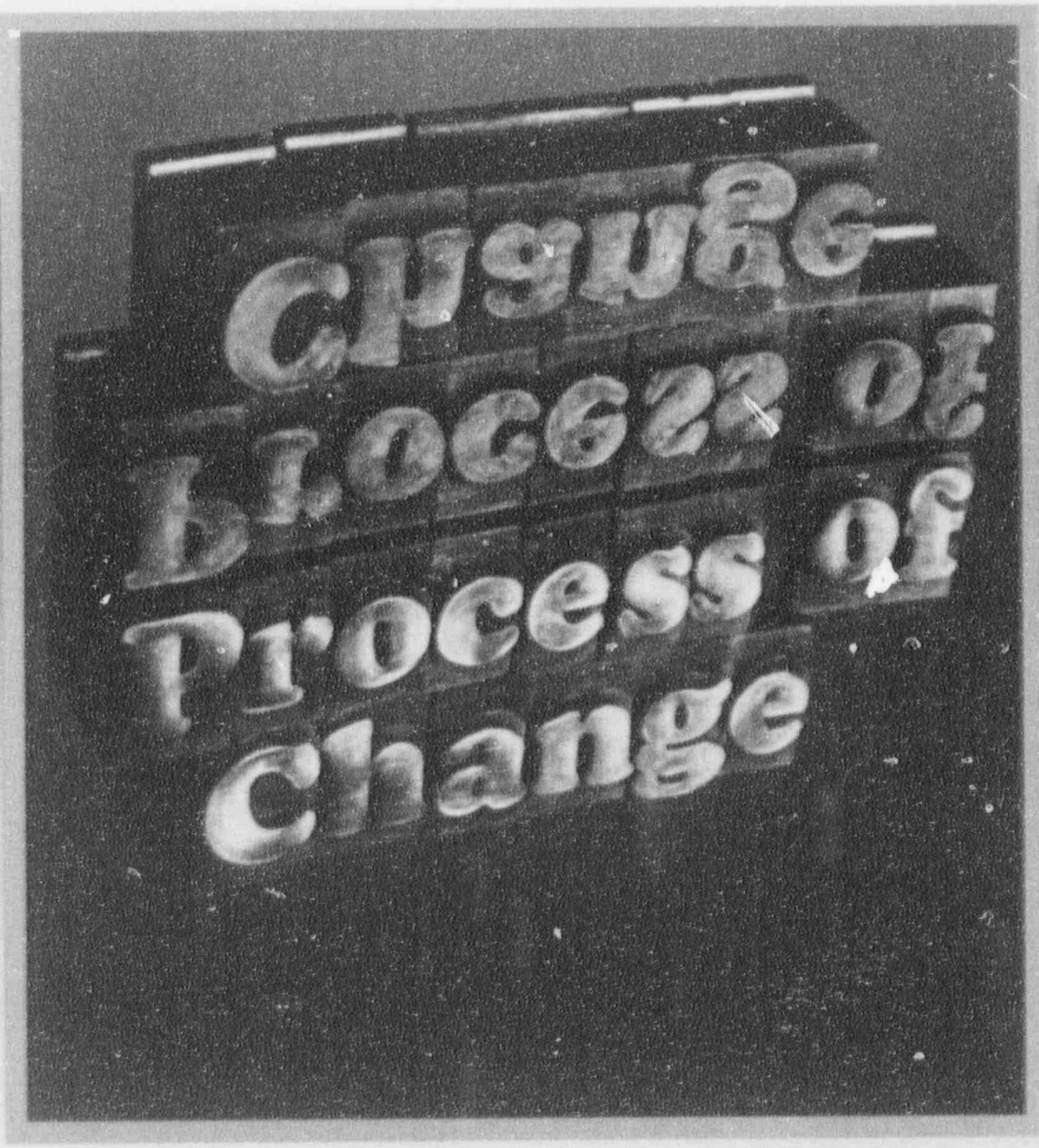
Gulf States Utilities Co.

1992 Annual Report



1992 Points of Progress

- After Gulf States Utilities Co. and Entergy Corp. announced their proposed combination in June, shareholders of both companies gave their overwhelming approval in December.
- First mortgage bond refinancings during 1992 resulted in interest costs savings of almost $26 million on an annual basis.
- Preferred stock dividends became current, all preference stock dividend arrearages were met and all outstanding preference stock was redeemed.
- The redemption of preferred and preference stock reduced dividend requirements from about $62 million to about $40 million on an annualized basis.
- Kilowatt-hour sales were up 1 percent, continuing a five-year trend. Industrial sales rose 6 percent.
- The River Bend nuclear plant received a superior rating in one area of plant performance from the Nuclear Regulatory Commission and good ratings in the other six areas.
- Economic activity in the service area continued to grow, with more than 9,600 new customers hooked up during the year, almost 7,900 of them residential customers. For the first time since 1983, every division in the company saw positive customer growth.
- GSU's aggressive economic development efforts resulted in announcements of 2,800 manufacturing jobs during 1992 from 54 new or expanding industries.
- The Team City success story continued, with 87 communities remaining active in the economic development partnership. Twenty of these were recertified during the year.

ABOUT THE COVER

Changes that have rocked the electric utility industry in recent years have been reflected in Gulf States Utilities Co. The challenge faced by GSU has been one of transforming negative change to positive results.

P R O C E S S O F C H A N G E

Description of Business

Gulf States Utilities Co. generates, transmits and sells electricity to more than 588,000 customers in a 28,000 square mile area that spans the Gulf Coast between Houston and New Orleans.

The territory served by Gulf States has a population of about 1,540,000 and includes the northern suburbs of Houston and the major cities of Conroe, Huntsville, Beaumont and Port Arthur in Texas and Lake Charles and Baton Rouge in Louisiana.

In 1992, GSU provided wholesale service to six municipalities and three rural cooperatives in both states and supplied steam and electricity to a large industrial customer though a cogeneration facility in Baton Rouge. Gulf States is a partner in a cogeneration project near Lake Charles, the Nelson Industrial Steam Co.

The company owns and operates a natural gas retail distribution system serving almost 85,000 customers in the Baton Rouge area.

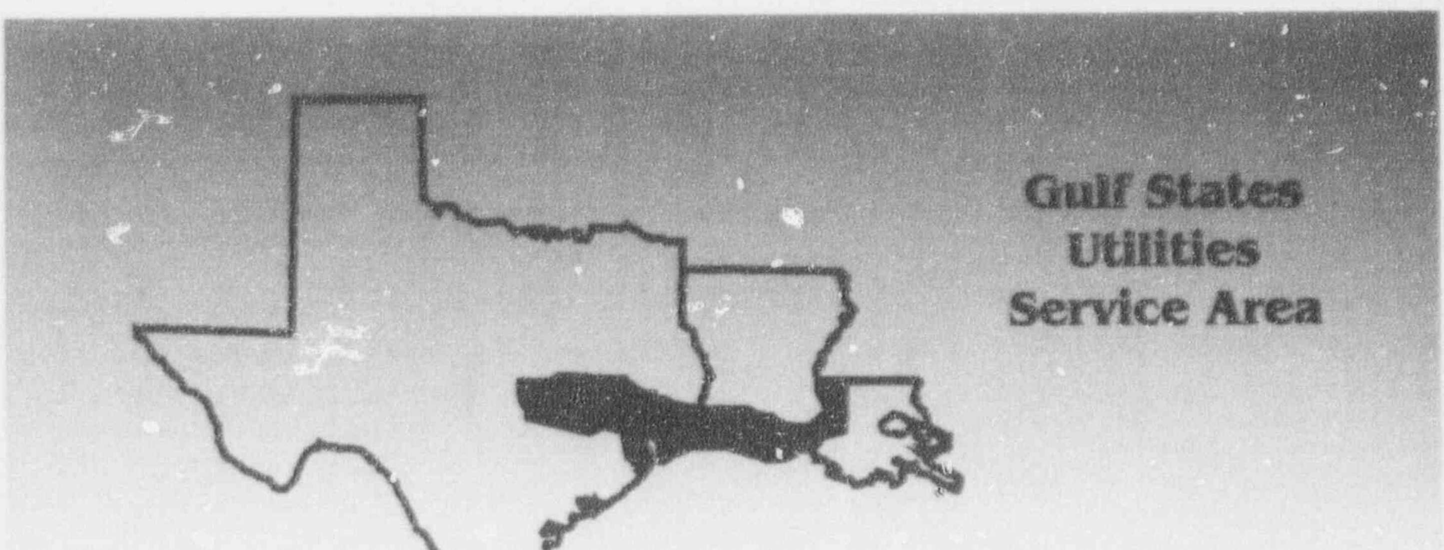
As part of the Southwest Power Pool, GSU has the ability to interchange electricity with 43 other members (29 full members, which includes GSU, and 15 associate members) in eight states in the South and Southwest.

In 1992, Gulf States had a peak load of 5,247 megawatts. Normal dependable capacity and firm purchased power agreements totaled 6,709 megawatts at the time of the peak on July 7.

GSU headquarters is located at 350 Pine St., Beaumont, Texas.

Table of Contents

Financial Highlights	1992	1991	% Change
Operating Revenues (000)	$1,773,374	$1,702,235	4.2
Operating Expenses and Taxes (000)	$1,439,272	$1,356,255	6.1
Net Income (000)	$ 128,157	$ 102,283	25.3
Income Applicable to Common Stock (000)	$ 78,455	$ 39,213	100.1
Earnings per Average Share of Common Stock Outstanding	$ 0.69	$ 0.34	102.9
Dividends per Share of Common Stock	—	—	—
Average Common Shares Outstanding (000)	114,055	114,055	—
Number of Electric Customers (end of year)	588,312	578,693	1.7
Total Kilowatt-Hour Sales (000)	29,27[illegible],738	29,069,349	.7
System Peak Load – Megawatts	5,247	5,224	.4



Joseph L. Donnelly
Chairman of the Board, President and Chief Executive Officer

Dear Fellow Shareholders:

While political candidates talked of change in 1992, Gulf States Utilities and its employees were experiencing it. Significant changes impacted the electric utility industry itself, as well as GSU's executive leadership, its financial standing and the economy of its service area. Even without the June 8 merger announcement, 1992 was destined to be a year dominated by the *process of change*.

1992 was a year that began with major change and ended with the company poised in an entirely new direction — toward becoming part of one of the largest and most successful utilities in the country. This was monumental change for a company teetering dangerously on the brink of bankruptcy just a few years ago.

GSU continued to battle back in 1992 from the financial morass that mired this company during much of the last decade. The Financial Highlights in this report show a company making significant strides. Gone are the negative numbers that dotted our financial statements with such dire regularity. Replacing them are upward trends in earnings and sales.

For the second year in a row we have been able to report to you positive earnings on your investment. Earnings per share of common stock more than doubled from last year — to 69 cents in 1992, up from 34 cents per share recorded for 1991. Contrast that with the 99-cent loss in 1990 and the $1 loss we recorded in 1989.

Sales have increased for the fifth consecutive year. Industrial sales lead the way, showing a 6 percent growth over the previous year. Overall kilowatt-hour sales increased modestly during the year to 29.3 billion kilowatt-hours from the 29.1 billion in 1991. Moderate weather during much of the year resulted in a slight decrease in residential sales during 1992. Taken as a whole, however, our sales point to an improved economic climate in the area we serve.

PROCESS OF CHANGE

Report to Shareholders

Our financial position rallied to such a degree last year that we were able to pay the preferred dividend arrearages and to resume regular dividend payments on preferred stock. We also paid the preference dividend arrearages and redeemed the outstanding preference stock. The one dark spot remaining in this otherwise brighter financial picture is that we have been unable to resume payment of common stock dividends. Our aim remains to resume common stock dividends as soon as practicable.

The biggest change — possibly the biggest in the company's history — came in June with the announcement of a proposed merger between Gulf States Utilities and Entergy Corp. The favorable reception has been overwhelming. At a special shareholders meeting in mid-December, 98 percent of the GSU shareholders voting approved the proposed merger. This is a gratifying vote of confidence from you, our shareholders. The merger will be completed once a series of regulatory approvals have been obtained.

Despite the progress made in GSU's hard-fought struggle for financial stability, we came to recognize that a merger was the fastest and best way to create shareholder value and to ensure a stable future. By joining forces with a financially secure company such as Entergy Corp., we will be better able to cope with the uncertainty of today's competitive environment. Shareholders and customers alike stand to benefit by this move.

Sweeping changes buffeted our industry in recent years with challenges never faced before. Many of them have been brought about by deregulation. At every turn — in the generation, transportation and sale of electricity — Gulf States has been at the forefront of the windstorm of change blowing through this business.

As this new age of the utility industry evolves, companies will be judged by how well they perform in the competitive marketplace. We are working diligently to make the merger with Entergy a reality. But in any event, Gulf States Utilities is poised to grow and improve as this decade unfolds.

Sincerely,

Joseph L. Donnelly

Chairman of the Board,
President and
Chief Executive Officer

February 12, 1993

__Listed__ in this section are the events that affected your company during 1992.

Gulf States Utilities Co. reported 1992 earnings of 69 cents per share of common stock, compared with 34 cents per share for 1991.

Results for 1992 benefited from reduced interest charges, reduced preferred and preference dividend requirements and a reduction to the liability previously recorded for the settlement of a purchased power dispute.

Kilowatt-hour sales were 29.3 billion in 1992, a 1 percent increase from the 29.1 billion in 1991. This marked the fifth year in a row that electric sales increased.

Residential sales in 1992 were slightly less than in 1991, reflecting moderate weather conditions in both the summer and winter. Industrial sales were about 6 percent higher than in 1991, but were somewhat offset by decreased sales for resale.

There was considerable financing activity during 1992 as Gulf States took advantage of lower interest rates to significantly reduce future interest expenses.

GSU sold $1.2 billion of first mortgage bonds during the year, issuing $300 million in January, $600 million in April and another $300 million in November. The interest rates on the new bonds range from 6.67 percent to 8.94 percent while the $982 million of first mortgage bonds retired with the proceeds of the new bonds had interest rates from 10.125 percent to 16.8 percent. The company estimates it will save about $25.9 million in annual interest costs from refinancing the bonds.

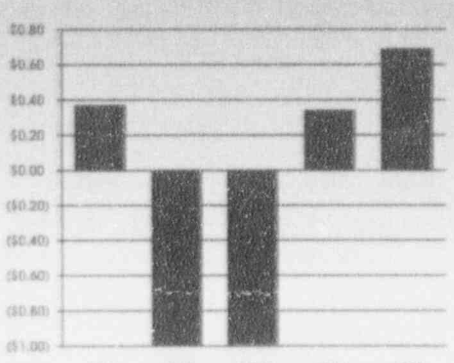
Some of the proceeds from the April first mortgage bond issue were also used to pay a portion of the preference stock dividend arrearage and to retire all $100 million of preference stock outstanding, resulting in annual dividend savings of $16.5 million.

In 1992 and early 1993, the company refunded $65.7 million of pollution control bonds issued in 1982 and 1983. The August refunding replaced 10.375 percent bonds with an issue of 6.75 percent bonds, and the proceeds from a January 1993 issue of 6.7

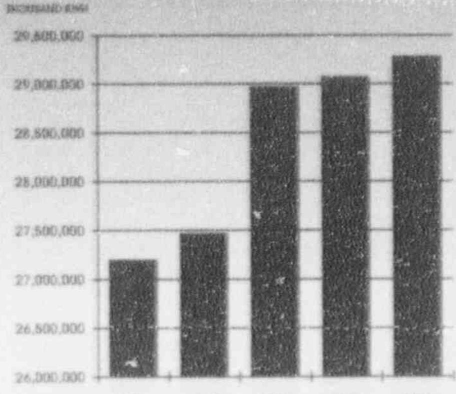
P R O C E S S O F C H A N G E

1992 Year in Review

EARNINGS PER SHARE OF COMMON STOCK



ELECTRIC SALES



percent bonds will be used to retire 9.5 percent bonds in March 1993. Annual interest savings from these two refundings total more than $2.2 million.

Finally, Gulf States retired $55.9 million of preferred stock, including sinking fund arrearages, at par in 1992. Annual dividend savings are estimated to be about $5.9 million.

A major part of the change at Gulf States during 1992 came at the top of the corporate ladder. Joseph L. Donnelly, who had been elected chief executive officer of GSU in January, became chairman of the board in March and president in July.

Donald M. Clements Jr. was named vice president of strategic projects in July with responsibility for coordinating the proposed business combination with Entergy.

Additional organizational changes took place in November.

Calvin J. Hebert, senior vice president, assumed responsibility for division operations, including operations, customer service and marketing activities throughout the company.

James C. Deddens, who had been senior vice president of the River Bend Nuclear Group, was named senior vice president of special projects. He is retiring this spring.

Philip D. Graham was promoted from plant manager at River Bend to vice president and Joseph F. Schippert, an assistant plant manager, succeeded Graham as plant manager.

Ronald M. McKenzie, who had been vice president of the Port Arthur Division, was named vice president of information services. What had been the Port Arthur and Beaumont Divisions were combined as the Southeast Texas Division in December 1992.

Employees continue their same activities, and service remains at the same high level. In fact, because of our service people, the clerks who take customer payments, the employees who provide energy information to individuals and to schools and organizations, more than 91 percent of customers surveyed have a very good or good opinion about Gulf States.

During 1992, Gulf States became current on all its preferred stock dividends and paid all dividends in arrears on its preference stock.

Hurricane Andrew hits Louisiana service area

Hurricane Andrew slammed into the Louisiana coast on Aug. 26 leaving a path of destruction through much of GSU's eastern Louisiana service area before fizzling out in Mississippi.

When Andrew crossed the Florida peninsula and entered the Gulf of Mexico, GSU began marshaling its forces, having employees and contract workers ready to move wherever help was needed.

When it became apparent the evening of Aug. 25 that Louisiana was Andrew's target, GSU began moving crews from its far western reaches to Beaumont where they waited for the brunt of the hurricane to pass so they could safely enter the stricken areas.

Although about 180,000 customers in the Lafayette to Baton Rouge area were without power in the wake of the hurricane, service was restored to all customers GSU knew were without electricity in about a week. GSU's service restoration crews were bolstered by about 1,700 additional line and tree trimming workers, including other GSU employees, contract workers and employees from nearby utilities.

Damage to the company's transmission and distribution system totaled more than $22 million, but this expense was covered by insurance and by a storm damage reserve maintained by GSU.

In communicating with employees after the storm, chief executive Joseph L. Donnelly called the restoration activities "a true team effort" by those actually restoring power and those working behind the scenes serving meals, fielding phone calls and other important, but sometimes overlooked, tasks.

Preferred and preferrence stock dividends had not been current since the fourth quarter of 1986.

Common stock dividends were suspended after the second quarter of 1986 and have not been resumed. Unfortunately, Gulf States is still not in a financial position to pay common dividends, although resumption of this class of dividends remains the company's highest priority.

The preferred dividend payment of $115.7 million made on March 15, 1992, representing nine quarters in arrears and the current quarter, made the company current on this class of stock. The June 15, 1992, payment represented the first regular quarterly payment and preferred dividend obligations have been met in each of the subsequent quarters. The company also became current on its preferred stock sinking fund obligations in April.

In June, GSU paid all preference stock dividend arrearages and redeemed the stock. Part of the proceeds of a first mortgage bond sale, plus general corporate funds, covered the $90.3 million of dividends in arrears and the $118.3 million cost of redemption.

Through redemption of its preferred and preference stock, the company reduced its preferred and preference dividend requirement in 1992 from about $62 million to about $40 million on an annualized basis.

The Baton Rouge federal district judge presiding over the lawsuit Cajun Electric Power Cooperative filed against Gulf States in 1989 appointed a mediator in March. The two parties began discussions with the mediator, a retired federal appeals court judge, in July.

The electric co-op, a 30 percent owner of the River Bend nuclear power plant, contends, among other things, that GSU misrepresented the plant's construction costs in order to entice Cajun to participate in the project. The company believes the lawsuit is without merit.

PROCESS OF CHANGE

Directors

--From left: (seated)
*Bismark A. Steinhagen, elected 1974, Chairman of the Board, Steinhagen Oil Co. Inc., Beaumont, Texas
**Paul W. Murrill, elected 1978, Retired Chairman of the Board and Chief Executive Officer, Gulf States Utilities Co., Beaumont, Texas
M.Bookman Peters, elected 1990, CPA and financial consultant and former Chairman of the Board and CEO, First City Texas, Bryan, Texas
--(standing)
*Joseph L. Donnelly, elected 1986, Chairman of the Board, President and Chief Executive Officer
*Robert H. Barrow, elected 1984, General, Retired Commandant United States Marine Corps, St. Francisville, La.

*Executive Committee
**Chairman Executive Committee

In November, two members of Cajun Electric filed suit in federal court in Lafayette, La., to dissolve Cajun's 30 percent interest in River Bend. They contend Gulf States failed to get an allegedly required LPSC approval of the joint operating agreement. The company believes this suit also is without merit.

In January 1992, Gulf States filed an application with the Public Utility Commission of Texas to reconcile all its fuel and purchased power costs through September 1991 and to establish a new fuel factor. As 1993 began, the case was still pending.

If the PUCT approves GSU's application, there will be little impact on customers' bills. Fuel costs are passed on directly to customers, with Gulf States making no profit. The commission requires Texas utilities to periodically reconcile their fuel costs and to change fuel factors to reflect the actual cost of fuel. The company expects to have a decision sometime during the first half of 1993.

In October, the 3rd District Court of Appeals in Austin heard oral arguments on GSU's appeal of a 1988 PUCT decision in the River Bend rate case. The issue on appeal is whether the original River Bend case, decided in 1988, should be remanded to the PUCT since the regulators failed to make a decision regarding $1.4 billion on a systemwide basis of the plant investment.

The three-judge panel has no deadline for handing down a ruling.

In late January 1992, the Louisiana Public Service Commission reconfirmed–with modifications–a deregulated asset plan covering the River Bend construction costs disallowed by the commission in December 1987.

The plan allows shareholders and ratepayers to benefit equally from any revenues above a certain amount realized from off-system sales from the deregulated portion of River Bend. No write-down had to be taken for the deregulated portion of the plant, but an increase in deferred taxes caused a net $7.1 million charge to net income in 1991.

--from left (seated)
*Sam F. Segnar, elected 1986. His interests include aviation, construction and development, The Woodlands, Texas
Monroe J. Rathbone Jr., elected 1975, Medical Director of Our Lady of the Lake Regional Center, Baton Rouge, La.
James E. Taussig II, elected 1975, President, Taussig Corp., Lake Charles, La.
Frank W. Harrison Jr., elected 1990, Independent Geologist, Lafayette, La.
--(standing)
Eugene H. Owen, elected 1989, Chairman of the Board and Chief Executive Officer, Owen & White Inc., Baton Rouge, La.;
William F. Klausing, elected 1991, Retired, Senior Vice President and Manager, Irving Trust Co.'s Public Utility Division, New York, N.Y.

In July the company returned to customers half of a $24 million LPSC-ordered refund representing return on equity overcollections. The remaining half will be paid in July 1993.

The year was not a normal one for the River Bend nuclear power plant near St. Francisville, La. Historically, the unit has operated at or above industry standards, but an extended outage for refueling, repairs and routine maintenance meant the plant was out of service for half the year–from March to September.

A real positive from the plant's fourth refueling outage was that the company was able to load enough fuel to extend the next cycle by about two months, until March 1994.

During the planned outage, workers chemically cleaned the service water system and converted it from an open to a closed loop system. This will resolve corrosion problems in the system. Workers also repaired a cracked weld in a feedwater nozzle attachment.

The Nuclear Regulatory Commission issued its Systematic Assessment of Licensee Performance, or "report card," on River Bend in November giving emergency preparedness a Category 1, or superior rating. The six other plant performance categories received good ratings–Category 2. The report covered the period of April 1, 1991, through Sept. 26, 1992.

In its report the regulatory agency did point out that the extended refueling and maintenance outage during the assessment period "stressed your programs and, in some cases, affected overall performance."

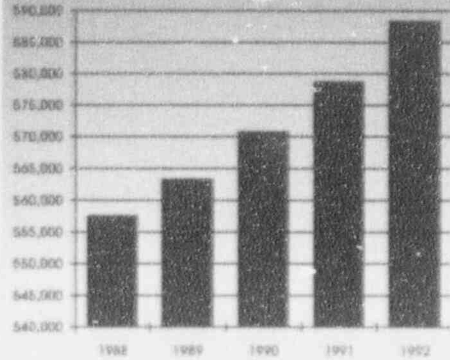
The NRC informed GSU in late December 1992 that it proposed to fine the company $100,000 for violations of NRC radiation protection requirements related to two incidents involving mishandling of radioactive material which occurred during the fourth refueling outage. Both incidents were reported by GSU to the regulatory agency.

The NRC acknowledged that the company took immediate action to restore compliance and assure safety, and has taken comprehensive action to eliminate radiation protection program weaknesses and ensure against a recurrence of these violations.

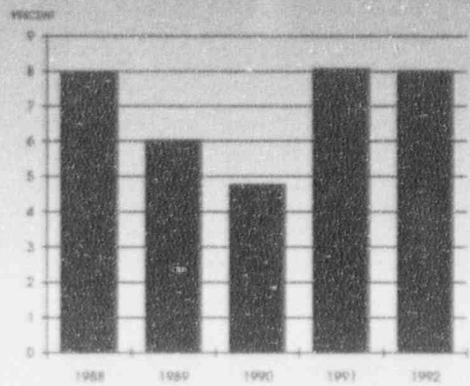
P R O C E S S O F C H A N G E

1992 Year in Review

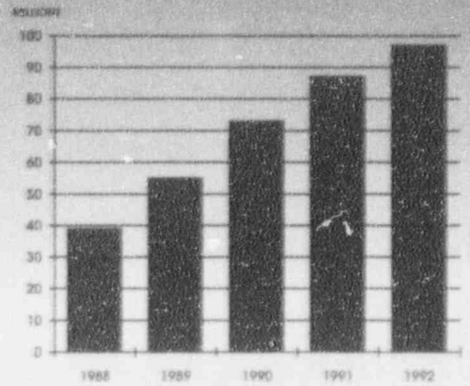
ELECTRIC DEPARTMENT CUSTOMERS



RETURN ON AVERAGE CAPITALIZATION



CONSTRUCTION EXPENDITURES



Gulf States paid the fine in late January.

Meanwhile, Gulf States' fossil-fueled plants, considered the backbone of the system, performed like champions, exceeding their reliability, availability and heat rate goals.

The natural gas- and coal-fueled power plants generated 21.3 million megawatt-hours of electricity during 1992, a 4 percent increase over the previous year and the most mwh generated since 1984 when a long-term very low cost gas contract expired.

One of the units, Sabine 4, turned in the best performance in the system, with a capacity factor of 83.4 percent, which is the plant's actual generation stated as a percentage of its maximum capability.

In addition, the fossil system was available for service 86 percent of the time in 1992, the best in 25 years.

The Nelson Industrial Steam Co. dedicated its $220 million cogeneration unit at Gulf States Utilities' Nelson Station near Lake Charles, La., in September. The facility has been running smoothly since beginning operation.

The four-partner joint venture was formed in 1988 to generate electricity for sale to GSU and to supply steam to some of the industrial partners. Members of the group are GSU, CITGO Petroleum Corp., Conoco Inc. and Vista Chemical Co.

Gulf States operates the facility which uses new fluidized-bed combustion technology. Locally produced fuel-grade petroleum coke serves as the primary fuel.

Gulf States' contribution to the project was two of its existing generating units at the Nelson site. The three industrial partners financed the conversion of the units to burn the coke.

Because of NISCO, the industrial partners will be able to maintain and expand their operations in Southwest Louisiana and Gulf States, by retaining these three large customers, is able to offer more competitive electric rates to all of its other customers.

Glenda Broussard

First Class Electrician Glenda Broussard, one of four GSU employees injured in an explosion at the Sabine Station power plant near Bridge City, Texas, on Jan. 5, 1993, died at a Galveston hospital on Jan. 22.

Flags in all company facilities were flown at half-staff the day of her death.

The last GSU fatality at a company power plant occurred 20 years ago at the Nelson Station in Westlake, La.

A 12-year Gulf States' veteran, Mrs. Broussard, two other electricians and an equipment operator were working on a large circuit breaker at the plant when, for reasons still undetermined, the breaker exploded, critically injuring all four.

At the time this report was written, the three injured employees were making slow recoveries from their burns at Hermann Hospital in Houston. They are Jeff Hollis, equipment operator, and Larry Sam and Allen Daniel, first class electricians.

GSU's first natural gas storage facility in Beaumont's historic Spindletop Oil Field went into operation in October 1992, with a second one scheduled for completion by July 1, 1994. Work began on the project in November 1991.

Sabine Gas Transmission Co. of Houston owns the storage facility and is under contract to provide GSU with transportation and swing service of natural gas to the nearby Sabine power plant. With the storage facility, Gulf States can purchase natural gas when prices are low for use when fuel costs escalate or when demand for electricity is high.

Plans call for the 1.3 billion-cubic-foot cavern completed in 1992 to be enlarged to more than 5 bcf by mid-1996. Work is now underway on the second storage cavern, a 5 bcf-plus facility.

Employment practices for the 4,841 Gulf States employees are guided by the principles of equal opportunity for all. It is partially through affirmative action programs that the company has been able to hire skilled personnel from all community sectors.

Fair employment policies assist GSU in developing its human resources to serve our customers more effectively.

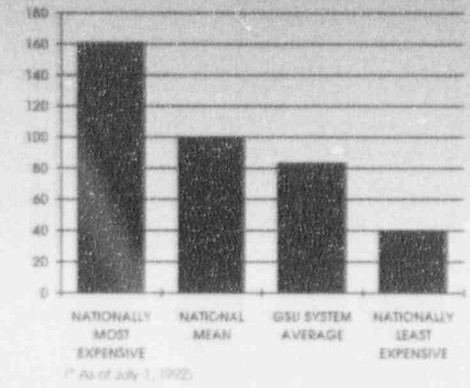
GSU and the International Brotherhood of Electrical Workers, Local 2286, reached agreement on a new three-year contract effective June 21, 1992.

Under the provisions of the agreement, a 3 percent wage increase became effective immediately and was followed by a 2 percent increase on Dec. 20. Subsequently, 2 percent increases are scheduled for June and December until the expiration of the contract on June 24, 1995.

P R O C E S S O F C H A N G E

1992 Year in Review

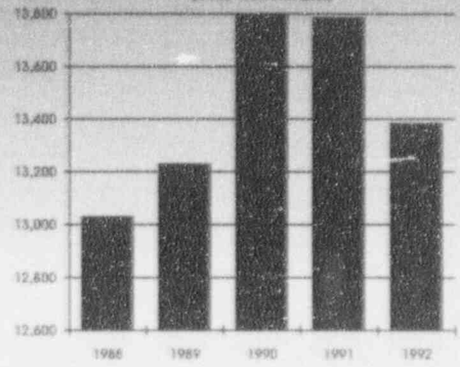
RESIDENTIAL COST PER 1,000 KWH'S*



(* As of July 1, 1992)

AVERAGE RESIDENTIAL ELECTRIC USE

(PER CUSTOMER)



The Merger Process

The first major step in the combination of Gulf States Utilities Co. and Entergy Corp. was taken in mid-December when shareholders of both utilities voted overwhelmingly in favor of the merger.

Applications for approval have been filed with Texas and Louisiana utility regulators, asking them to declare the merger in the public interest. Filings have been made with the Federal Energy Regulatory Commission and other federal agencies. Status of the proceedings at the end of January was:

Several rounds of hearings were conducted by the Louisiana Public Service Commission during the last quarter of 1992 with additional hearings scheduled for early 1993. A decision could come in April 1993.

In Texas, the merger hearings are scheduled to get underway March 8. GSU and Entergy have asked for a decision by mid-1993. The Public Utility Commission staff in January 1993 filed testimony recommending the PUCT find the proposed merger to be in the public interest with some minor qualifiers. Intervenors who filed testimony did not oppose the merger on its face, but did list a number of conditions they felt should be met before the merger is declared to be in the public interest. These conditions related primarily to the sharing of projected savings between ratepayers and shareholders.

The Federal Energy Regulatory Commission issued an order on Jan. 27, 1993, instructing the administrative law judge to have a recommendation by Aug. 31. The FERC decided that hearings only needed to be held on the proposed merger's effect on operating costs and rate levels, the accounting treatment of the merger and the proposed amendment to Entergy's system agreement to include Gulf States.

The Nuclear Regulatory Commission on Jan. 13, 1993, was asked to consent to the change in control of Gulf States and to amend the operating license for River Bend to permit an Entergy nuclear subsidiary to operate the plant on behalf of Gulf States and Cajun Electric Power Cooperative, the plant's owners.

Entergy made application for approval of the merger in August to the Securities & Exchange Commission under the Holding Company Act.

GSU and Entergy have asked the Internal Revenue Service for a letter stating the transfer of stock will be tax free.

Still to be filed is an application under the Hart/Scott/Rodino antitrust provisions with the Federal Trade Commission and the Department of Justice.

The major elements of the proposed combination, announced June 8, 1992, call for GSU shareholders to receive $20 per share in cash or stock once the merger is completed. There are provisions for adjustments to the price, depending upon whether GSU pays any common stock dividends prior to completion of the merger or if the transaction is not finished by June 5, 1994.

According to testimony filed with regulators, the merger will result in savings of about $1 billion over ten years. This includes lower fuel costs which would go into effect immediately, plus operating cost savings realized through the combined operations of the systems. In addition, base rates will be capped at current levels for at least five years.

Financial Information

Financial Information

FINANCIAL SECTION

Contents

Management Responsibility for Consolidated Financial Statements

Management is responsible for the preparation, integrity, and objectivity of the consolidated financial statements of Gulf States Utilities Company. The statements have been prepared in conformity with generally accepted accounting principles and, in some cases, reflect amounts based on estimates and judgement of management, giving due consideration to materiality.

The Company maintains an adequate system of internal controls to provide reasonable assurance that transactions are executed in accordance with management's authorization, that the consolidated financial statements are prepared in accordance with generally accepted accounting principles, and that the assets of the Company are properly safeguarded. The system of internal controls is documented, evaluated, and tested by the Company's internal auditors on a continuing basis. No internal control system can provide absolute assurance that errors and irregularities will not occur due to the inherent limitations of the effectiveness of internal controls; however, management strives to maintain a balance, recognizing that the cost of such a system should not exceed the benefits derived.

Coopers & Lybrand, independent accountants, is engaged to audit, in accordance with generally accepted auditing standards, the consolidated financial statements of the Company and issue their report thereon, which appears on page 48. Coopers & Lybrand conducts a review of internal accounting controls to the extent required by generally accepted auditing standards and performs such tests and procedures as they deem necessary to arrive at an opinion on the fairness of the consolidated financial statements presented herein.

The Board of Directors, through its Audit Committee, has general oversight of management's preparation of the consolidated financial statements and is responsible for engaging, subject to shareholder approval, the independent accountants. The Audit Committee, comprised entirely of outside directors, reviews with the independent accountants the scope of their audits and the accounting principles applied in financial reporting. The Audit Committee meets regularly, both separately and jointly, with the independent accountants, representatives of management, and the internal auditors, to review activities in connection with financial reporting. The independent accountants have full and free access to meet with the Audit Committee, without management representatives present, to discuss the results of their audits.

Common Stock Prices and Dividends Per Share

For the years ended December 31

1992	High	Low	Cash Dividends Paid Per Share
First Quarter	$13¼	$10⅛	$ —
Second Quarter	16¼	12⅝	—
Third Quarter	16⅜	15⅛	—
Fourth Quarter	16¾	15¾	—

1991	High	Low	Cash Dividends Paid Per Share
First Quarter	$12¼	$10⅜	$ —
Second Quarter	12	8⅞	—
Third Quarter	10¾	9¼	—
Fourth Quarter	10⅜	8½	—

The Common Stock of the Company is listed on the New York, Midwest, and Pacific Stock Exchanges. The number of common shareholders of record on December 31, 1992, was 48,721.

Selected Consolidated Financial Data
(in thousands except per share amounts and ratios)

For the Years Ended December 31	1992	1991	1990	1989	1988
Operating Revenue	$1,773,374	$1,702,235	$1,690,685	$1,607,406	$1,520,477
Income (Loss) Before Extraordinary Items and the Cumulative Effect of Accounting Changes	133,787	122,449	(44,282)	13,251	117,512
Net Income (Loss)	128,157	102,283	(44,282)	(45,573)	103,143
Income (Loss) Applicable to Common Stock	78,455	39,213	(107,024)	(108,412)	40,079
Earnings (Loss) Per Average Share of Common Stock Outstanding Before Extraordinary Items and the Cumulative Effect of Accounting Changes	.74	.52	(.99)	(.46)	.50
Earnings (Loss) Per Average Share of Common Stock Outstanding	.69	.34	(.99)	(1.00)	.37
Dividends Per Share of Common Stock	—	—	—	—	—
Return on Average Common Equity	3.93%	1.99%	(5.44)%	(5.29)%	1.95%
As of December 31					
Total Assets	$6,858,494	$6,911,492	$6,863,269	$6,807,894	$6,941,531
Long-Term Debt and Preferred Stock Subject to Mandatory Redemption	2,629,028	2,656,562	2,512,743	2,801,860	2,990,934
Capital Lease Obligations (Current and Non-Current)	206,611	138,133	161,065	180,552	98,852
Book Value Per Share	17.30	16.77	16.81	17.80	18.80
Capitalization Ratios:					
Common Shareholders' Equity	41.6%	41.1%	41.2%	39.8%	39.3%
Preferred and Preference Stock	8.3	12.2	14.4	12.9	11.7
Long-Term Debt	50.1	46.7	44.4	47.3	49.0
	100.0%	100.0%	100.0%	100.0%	100.0%

See Notes 3 and 4 to the Consolidated Financial Statements regarding contingencies, current rate matters involving possible disallowances and write-offs, and accounting standards.

Management's Discussion and Analysis of Financial Condition and Results of Operations

In reviewing Management's Discussion and Analysis of Financial Condition and Results of Operations and the Consolidated Financial Statements of the Company, attention should be given to the disclosure in Notes 3 and 4 to the Consolidated Financial Statements that certain litigation and regulatory contingencies exist and the possible consequences if such contingencies are ultimately resolved adversely to the Company.

Proposed Entergy Corporation/Gulf States Utilities Company Business Combination

On June 5, 1992, the Company entered into an Agreement and Plan of Reorganization with Entergy Corporation (Entergy). The common shareholders of the Company and Entergy approved the business combination at special shareholders meetings on December 17, 1992. The business combination remains subject to certain conditions, including among others, the receipt of necessary orders or other actions by the Public Utility Commission of Texas (PUCT), Louisiana Public Service Commission (LPSC), the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission (NRC), the Securities and Exchange Commission, and clearance under applicable federal anti-trust statutes.

Significant fuel and non-fuel savings are expected to result from the combination of the companies. The Plan of Reorganization provides for a five-year cap on the Company's base rates after consummation of the transaction.

Due to the numerous regulatory actions, which could take until at least late 1993 or early 1994, the risk of intervening material adverse events, and other numerous conditions and rights of terminations, there can be no assurance that the proposed business combination agreed upon will be consummated.

Results of Operations

Net income for 1992 increased, when compared to 1991, due primarily to increased revenues (as detailed below), reduced interest charges, and reductions to the Southern Company settlement liability. Increased operations and maintenance expenses offset in part the increases discussed above. Earnings per average share of common stock increased during 1992, when compared to 1991, due to the increases in net income discussed above, in addition to reduced preferred and preference dividend requirements.

Net income and earnings per share of common stock outstanding for 1991 increased when compared to 1990, due primarily to rate actions in Texas and Louisiana during the first quarter of 1991, increased kilowatt-hour sales, and reduced interest charges. The increase was offset in part by a $23,064,000 reserve (net of taxes), including interest, recorded in 1991, for a refund resulting from an April 1991 Louisiana Supreme Court ruling, and the increase in deferred taxes resulting from the discontinuation of regulatory accounting principles for the Louisiana deregulated portion of River Bend.

As of December 31, 1992, the Company has not recovered a significant amount of the investment or received any return associated with the portion of River Bend included in the deregulated asset plan in Louisiana and the portion of River Bend placed in abeyance as part of the Texas rate order entered on May 16, 1988, and which went into effect on July 23, 1988. Future earnings will continue to be limited as long as the limited recovery of the investment and lack of return continues.

For the year ended December 31, 1992, the Company recorded revenues resulting from the sale of electricity under the deregulated asset plan of approximately $40,000,000. Operations and maintenance expenses, including fuel, were approximately $38,108,000 and depreciation expense associated with the deregulated asset plan investment was approximately $16,597,000 for the year ended December 31, 1992. For the year ended December 31, 1992, the Company recorded non-fuel revenue of $30,637,000 (included in the $40,000,000 of total deregulated asset plan revenue discussed above) which, absent the deregulated asset plan, would not have been realized. The operations and maintenance expenses and depreciation expense allocated to the deregulated asset plan as detailed above, however, would have been incurred at River Bend with or without the deregulated asset plan. Future impact of the deregulated asset plan on the Company's results of operations and financial position will depend on River Bend's future operating costs, the unit's efficiency and availability, and the future market for energy over the remaining life of the unit. The Company anticipates that future revenues from the deregulated asset plan will fully recover all related costs.

Future results of operations could be adversely affected by substantial additional write-offs or write-downs of the Company's investment in River Bend and related deferred costs, which may result from regulatory actions, judicial actions, pricing energy below the full cost of service to meet competition and the associated application of accounting principles, or from periodic reevaluation of the deregulated asset plan in Louisiana. See Note 4 to the Consolidated Financial Statements for potential exposures. Substantial write-offs or write-downs would adversely affect the Company's capacity to continue to pay dividends and obtain financing, which could in turn affect the Company's liquidity. See "Liquidity, Financings, and Capital Resources" below.

Rate Matters

***Texas Retail Jurisdiction* (Regulator — PUCT)**

In the May 1988 rate order, Docket No. 7195, the PUCT set aside in abeyance $1.4 billion of the system-wide River Bend plant investment and $157,000,000 of related Texas retail jurisdiction deferred River Bend operating and carrying costs with no finding of prudency. The PUCT stated the ultimate rate treatment of such amounts would be subject to future demonstration by the Company of the prudency of such costs. Additionally, the PUCT affirmed its preliminary rulings in February 1988, to disallow as imprudent $63,468,000 of the Company's system-wide River Bend plant costs. The Company appealed the order and also filed a separate rate case (Docket No. 8702) in which it asked that the abeyed River Bend plant cost be found prudent and included in rate base. Intervening parties filed suit in district court to prohibit the proceedings in Docket No. 8702. The district court's decision in that suit was ultimately appealed to the Texas Supreme Court, and the Texas Supreme Court ruled that the prudence of the costs purported to be held in abeyance by the PUCT in its May 16, 1988 order could not be relitigated in a separate rate proceeding such as Docket No. 8702. The Texas Supreme Court's decision stated that all issues relating to the merits of the original order of the PUCT, including the prudence of all River Bend related costs, remain to be addressed in the pending district court appeal of Docket No. 7195. On October 1, 1991, a district court handed down its decision in the Company's appeal of the May 1988 rate order. The decision stated that, while it was clear the PUCT made an error in assuming it could set aside $1.4 billion of the total costs of River Bend and consider them in a later proceeding, the PUCT, nevertheless, found that the Company had not met its burden of proof related to the amounts placed in abeyance. The court also ruled that deferred costs associated with River Bend and Big Cajun 2 Unit 3 accrued after the units were placed in commercial operation, but prior to relevant rate orders, should not be included in rate base under the 1991 decision regarding El Paso Electric Company's (El Paso) similar deferred costs. The court remanded the case to the PUCT with instructions as to the proper handling of the deferred cost issues. The Company's motion for rehearing was denied, and on December 18, 1991, the Company filed an appeal of the October 1, 1991 district court order. The PUCT also appealed the October 1, 1991 district court order, which served to supersede the district court's judgment rendering it unenforceable under Texas law. On October 21, 1992, oral arguments were made before the Third District Court of Appeals on the Company's appeal. No assurance can be given as to the timing or outcome of the appeal.

As of December 31, 1992, on a Texas retail jurisdictional basis, the disallowed River Bend plant costs were approximately $18,000,000, and the River Bend plant costs held in abeyance totaled approximately $404,000,000, both net of accumulated depreciation and related taxes. As discussed in Note 4 to the Consolidated Financial Statements, on January 1, 1993, the Company is required to change its accounting for income taxes due to the adoption of Statement of Financial Accounting Standards (SFAS) No. 109. Included in the SFAS No. 109 accounting change is an increase of deferred taxes associated with the disallowed and abeyed River Bend plant investment. Accordingly, on January 1, 1993, after recognition of the SFAS No. 109 effect, the disallowed River Bend plant costs will be approximately $14,000,000, and the River Bend plant costs held in abeyance will total approximately $315,000,000, both net of accumulated depreciation and related taxes.

The River Bend cost deferrals associated with the portion of the investment held in abeyance amounted to approximately $161,000,000, net of taxes, as of December 31, 1992. River Bend cost deferrals which were allowed in rate base in Texas were approximately $101,000,000, net of taxes, as of December 31, 1992. At December 31, 1992, the Company estimates it had collected approximately $111,000,000 of revenues as a result of the previously ordered rate treatment of these deferred costs and currently estimates that it collects approximately $2,300,000 monthly, or $28,000,000 annually, of revenues associated with such deferred costs from ratepayers in Texas. Deferred costs associated with Big Cajun 2 Unit 3 totaled approximately $4,312,000 (net of taxes) as of December 31, 1992, of which approximately $1,823,000 (net of taxes) were included in rate base by the PUCT. The remaining $2,489,000 (net of taxes) of deferred costs were included in the appeal of Docket No. 7195 before the court.

On August 26, 1992, the court of appeals in the El Paso case handed down its second opinion on rehearing modifying its previous opinion on deferred accounting for El Paso (which had been relied upon by the district court in the Gulf States case). The court's new opinion distinguishes between deferred carrying costs and deferred operating and maintenance costs, concluding that the PUCT may lawfully defer operating and maintenance costs and subsequently include them in rate base, but that the Public Utility Regulatory Act prohibits such rate base treatment for deferred carrying costs. The court stated, however, its opinion would not preclude the recovery of deferred carrying costs without rate base treatment. The court of appeals opinion has been appealed to the Texas Supreme Court.

If the August 26, 1992 court of appeals opinion is applied to the Company by the courts and the PUCT permits recovery through amortization of the deferred carrying costs, the possible write-off of $101,000,000 of deferred River Bend costs currently allowed in rates would be eliminated, and possible refunds would be reduced. At December 31, 1992, the Company estimates it had collected approximately $53,000,000 of revenues as a result of the current inclusion of deferred carrying costs in rate base. The Company collects approximately $1,000,000 per month as a result of such current rate base treatment.

The October 1, 1991 district court order also found that the PUCT erred in reducing the Company's deferred costs by $1.50 for each $1.00 of revenue collected under the interim rate increases authorized in 1987 and 1988. Elimination of the reduction of deferred costs from rate base could reduce the potential refund of amounts described in the preceding paragraph by amounts ranging from approximately $15,000,000 to $36,000,000.

No assurance can be given as to the timing or outcome of the appeals described above. Pending further developments in these cases, the Company has made no write-offs for the River Bend related costs discussed above. Management believes, based on advice from Clark, Thomas, Winters & Newton, a professional corporation, legal counsel of record in the appeal of Docket No. 7195, it is reasonably possible that the Company will prevail on appeal of the district court order and the case will be remanded to the PUCT, and that it is reasonably possible that the PUCT will be allowed to expressly rule on the prudence of the abeyed River Bend plant costs. Upon remand of Docket No. 7195, the PUCT can choose from several options. It can reexamine all aspects of the case, reexamine only a portion of the case, take additional testimony, or rely on the existing record, including the report of the three administrative law judges that heard the extensive testimony filed in the case; or, the PUCT can take some action that may lead the parties to settle the case without additional extensive litigation. At this time, management and legal counsel are unable to predict the amount, if any, of the abeyed and previously disallowed River Bend plant costs that may be ultimately disallowed by the PUCT. A write-off as of December 31, 1992, ranging from $0 to $422,000,000, could be required based on the PUCT's ultimate ruling.

Management believes that it is reasonably possible that it will recover, in rate base, or otherwise through means such as a deregulated asset plan, all, or substantially all, of the abeyed River Bend plant costs. Management believes that the abeyed River Bend plant costs were prudently incurred. However, management recognizes that it is reasonably possible that not all of the abeyed River Bend plant costs may ultimately be recovered.

In prior proceedings, the PUCT has held that the original cost of nuclear power plants will be included in rates to the extent those costs were prudently incurred. Based upon the PUCT's prior decisions, management believes that its River Bend construction costs were prudently incurred.

As part of its direct case in Docket No. 8702, the Company filed a cost reconciliation study prepared by Sandlin Associates, management consultants with expertise in the cost analysis of nuclear power plants, which supports the reasonableness of the River Bend costs held in abeyance by the PUCT. This reconciliation study determined that approximately 82 percent of the River Bend cost increase above the amount included by the PUCT in rate base was a result of changes in federal nuclear safety requirements and provided other support for the remainder of the abeyed amounts.

There have been four other rate proceedings in Texas involving nuclear power plants. Investment in the plants ultimately disallowed ranged from 0 percent to 15 percent for three of the companies. A disallowance of approximately 25 percent was ordered in the other case, however, approximately 66 percent of that disallowance was recently overturned by a district court, which results in a net 9 percent disallowance. Each case was unique, and the disallowances in each were made on a case-by-case basis for different reasons. Appeals of most, if not all, of these PUCT decisions are currently pending.

The following factors support management's position that a loss contingency requiring accrual has not occurred, and its belief that all, or substantially all, of the abeyed plant costs will ultimately be recovered:

1. The fact that the $1.4 billion of abeyed River Bend plant costs have never been ruled imprudent and disallowed by the PUCT.
2. Sandlin Associates' analysis which supports the prudence of substantially all of the abeyed construction costs.
3. Historical inclusion by the PUCT of prudent construction costs in rate base.
4. The analysis of the Company's internal legal staff, which has considerable experience in Texas rate case litigation.

Additionally, management believes, based on advice from Clark, Thomas, Winters & Newton, a professional corporation, legal counsel of record in the appeal of Docket No. 7195, that it is probable that the deferred operating and carrying costs discussed above will be recovered in rates as allowable costs. However, assuming the August 26, 1992 court of appeals opinion in the El Paso case regarding deferred costs, as discussed above, is upheld and applied to the Company, and the deferred River Bend costs currently held in abeyance, related to the $404,000,000 of abeyed plant costs, are not allowed to be recovered in rates as allowable costs, a write-off of up to $161,000,000 could be required. In addition, future revenues based upon the deferred costs previously allowed in rate base could also be lost; and no assurance can be given as to whether or not refunds (up to $53,000,000 as of December 31, 1992) of revenue received based upon such deferred costs previously recorded will be required.

Adverse resolutions of these court appeals or subsequent regulatory proceedings, if remanded, could have a material adverse effect on the Company.

Louisiana Retail Jurisdiction (Regulator — LPSC)

On January 28, 1992, the LPSC ordered that the previously ordered deregulated asset plan be retained, subject to certain conditions. Such conditions include changing the sharing mechanism for incremental revenue derived from off-system sales from the previously ordered 60 percent for ratepayers/40 percent for shareholders to a split of 50 percent for ratepayers/50 percent for shareholders. Accordingly, the Company applied the provisions of SFAS No. 101, Regulated Enterprises — Accounting for the Discontinuation of Application of FASB Statement No. 71, which required no write-down of the deregulated portion of River Bend; however, the application of SFAS No. 101 did require an increase in deferred taxes and other adjustments of $20,166,000 ($.18 per share of common stock). Due to the Company's net operating loss carryforward position for Louisiana state income taxes, a previously unrecorded offsetting state tax benefit of $13,100,000 ($.12 per share of common stock) is included in "Income Taxes — State."

Liquidity, Financings, and Capital Resources

Funds provided by the sale of first mortgage bonds, operating activities, and existing funds, were the Company's primary source of funds during 1992, while the retirement of first mortgage bonds and preferred and preference stock, along with the payment of preferred and preference dividends, were the primary uses of funds during 1992.

In 1991, cash provided by operations and the sale of debentures were the most significant source of funds, while the retirement of long-term debt and payment of preferred dividends were the primary use of funds.

The following table shows selected cash flow items for the years 1992, 1991, and 1990:

	1992	1991	1990
		(in thousands)	
Funds Provided By			
Net operating activities	$ 365,125	$470,147	$363,788
Issuance of long-term debt	1,234,225	200,000	—
Existing cash and cash equivalents	95,320	—	930
Other	33,464	14,141	2,513
Total	$1,728,134	$684,288	$367,231
Funds Used For			
Capital expenditures	$ 97,377	$ 87,470	$ 73,020
Retirement of long-term debt, including redemption premiums, and deferred River Bend construction commitments	1,194,878	333,082	219,454
Retirement of preferred and preference stock, including redemption premiums	174,226	—	—
Payment of lease obligations	18,544	36,890	44,110
Payment of preferred and preference dividends	237,369	127,398	—
Investment in cash and cash equivalents	—	96,473	—
Other	5,740	2,975	30,647
Total	$1,728,134	$684,288	$367,231

As of December 31, 1992, the Company had available $100,000,000 under a bank credit agreement, as described in Note 11 to the Consolidated Financial Statements, which will expire March 15, 1993. The agreement contains negative covenants which, among other restrictions, restrict payment of dividends on and acquisition of common stock.

As discussed in Note 3 to the Consolidated Financial Statements, on January 4, 1993, the Company paid the Southern Company $111,329,000 to retire promissory notes and paid $6,471,000 under a common stock price differential agreement. The unpaid $48,671,000 of promissory notes and $2,829,000 of the common stock price differential is payable on the earlier of the January 1st as of which the Company has "adequate cash" or January 1, 1999, or earlier at the Company's discretion upon five days notice. In addition, there are $20,000,000 of pollution control bonds that are secured by a letter of credit which expires in April 1993. If the letter of credit is not renewed or replaced, the Company plans to remarket and cause the pollution control bonds to remain outstanding. If the Company is unsuccessful in these actions, the pollution control bonds will be redeemed.

The Company's funds provided from operations, along with available lines of credit, are expected to be sufficient to provide for the Company's cash requirements. However, if and to the extent other external funds are needed in the future, access to external funds could be adversely affected by economic or banking conditions, or adverse developments with respect to contingencies to which the Company is subject.

The Company's Mortgage Indenture contains an interest coverage covenant which limits the amount of first mortgage bonds which the Company may issue, based upon interest coverage for a period of twelve consecutive months within the fifteen months preceding a new debt issuance. Based upon the results of operations for the year ended December 31, 1992, during such fifteen month period, the Company believes it could issue $812,000,000 of additional first mortgage bonds, in addition to the amount presently outstanding (assuming an interest rate of 9 percent for additional first mortgage bonds).

The Company's Restated Articles of Incorporation, as amended, place earnings coverage limitations upon the issuance of additional preferred stock. On the basis of the results of operations for the year ended December 31, 1992, the Company believes it does not have the ability to issue additional preferred stock. There are no such limitations on the issuance of preference stock.

Significant Litigation, Risks, and Environmental Issues

As discussed below, and more fully in Note 3 to the Consolidated Financial Statements, significant litigation and other risks exist. The risks which management believes to be the most significant are discussed below.

Cajun Electric Power Cooperative, Inc. (CEPCO) Litigation. As discussed in Note 3 to the Consolidated Financial Statements, CEPCO has filed suit seeking recovery of its alleged $1.6 billion investment in River Bend as damages, plus attorneys' fees, interest, and costs. Two member cooperatives of CEPCO have brought an independent action to declare the River Bend ownership agreement void, based upon failure to get prior LPSC approval alleged to be necessary. The Company believes the suits are without merit and is contesting them vigorously. No assurance can be given as to the outcome of this litigation. If the Company were ultimately unsuccessful in this litigation and were required to make substantial payments, the Company would probably be unable to make such payments and would probably have to seek relief from its creditors under the Bankruptcy Code.

Nuclear Risks. Ownership and operation of a nuclear generating unit subject the Company to significant special risks. No assurance can be given that the amount of insurance carried as to various risks will be sufficient to meet potential liabilities and losses.

Environmental Issues. The Company has been notified by the U. S. Environmental Protection Agency (EPA) that it has been designated as a potentially responsible party for the cleanup of sites on which the Company and others have or have been alleged to have disposed of material designated as hazardous waste. The Company is currently negotiating with the EPA and state authorities regarding the cleanup of some of these sites. Several class action and other suits have been filed in state and federal courts seeking relief from the Company and others for damages caused by the disposal of hazardous waste and for asbestos-related disease which allegedly occurred from exposure on Company premises. While the amounts at issue in the cleanup efforts and suits may be very substantial sums, management believes that its financial condition will not be materially affected by the outcome of the suits.

Detailed below are the cumulative amounts accrued and expended, through December 31, 1992, for the cleanup of sites at which the Company has been designated as a potentially responsible party, in addition to the remaining estimated liability as of December 31, 1992.

	Amount Accrued through December 31, 1992	Amount Expended through December 31, 1992	Remaining Liability at December 31, 1992
		(in thousands)	
Environmental cleanup (six sites)	$25,568	$6,240	$19,328

The Federal Clean Air Act Amendments of 1990 impose new requirements to permit, measure, and control air pollution emissions from the Company's generating plants and will require additional capital expenditures for pollution control and measurement equipment and increased operating expenditures and permitting fees. Current estimates of expenditures to meet new requirements total approximately $22,000,000 over the next three to four years. Based upon the outcome of ongoing Company studies and depending upon pollution control standards to be set by the EPA and state environmental agencies, it may be determined that additional capital expenditures will be required above the present estimates.

Operating Revenue

Operating revenue increased in each of the years 1992, 1991, and 1990 as follows:

	Increase (Decrease) From Prior Year		
	1992	1991	1990
		(in thousands)	
Change in base rates	$ 354	$ 46,927	$12,894
Provision for rate refund — Louisiana	24,143	(24,143)	—
Fuel cost recovery	42,871	(21,842)	19,824
Sales volume and other	3,771	10,608	50,561
	$71,139	$ 11,550	$83,279
Percent increase over prior year	4%	1%	5%

Rates. The changes in base rates shown above reflect rate orders, settlement agreements, and rate changes implemented during the period from 1989 through 1991. The Company implemented permanent rate increases in each of the years 1989-1991.

As discussed in Note 4 to the Consolidated Financial Statements, in 1991, the Company recorded a $24,143,000 reserve for a refund to the Louisiana retail jurisdiction.

Fuel Cost Recovery. Fuel cost recovery revenue increased (decreased) as detailed above, due primarily to changes in fuel and purchased power costs discussed below.

Kilowatt-Hour Sales. Kilowatt-hour sales changes for the years 1992, 1991, and 1990 in total and for the three major kilowatt-hour sales categories are as follows:

	Increase (Decrease) from Prior Year		
	1992	1991	1990
Residential	(1)%	1%	6%
Commercial	—	1	4
Industrial	6	2	8
Total	1	—	5

See the Statistical Summary for additional information on kilowatt-hour sales and related revenues by customer class.

Industrial Sales. Cogeneration projects developed or considered by certain industrial customers over the last several years have resulted in the Company developing and securing approval of rates lower than the rates previously approved by the PUCT and LPSC for such industrial customers. Such rates are designed to retain such customers, and to compete for and develop new loads, and do not presently recover the Company's full cost of service. Sales to those customers qualifying for such rates remained at virtually the same level during 1992, when compared to 1991, after relatively large increases over the prior several years. The pricing agreements at non-full cost of service based rates fully recover all related costs but provide only a minimal return. Substantially all of such pricing agreements expire no later than 1997. Kilowatt-hour sales, changes in kilowatt- hour sales, and related revenue within the industrial class are detailed below:

	1992	1991	1990
		(in thousands)	
Sales — Kilowatt-hours			
Full cost of service based rates	10,948,865	10,188,808	10,265,998
Non-full cost of service based rates	3,447,811	3,423,389	3,065,774
Total Industrial	14,396,676	13,612,197	13,331,772

	Increase (Decrease) from Prior Year		
	1992	1991	1990
Changes in Kilowatt-hour Sales			
Full cost of service based rates	7%	(1)%	1%
Non-full cost of service based rates	1	12	45
Total Industrial	6	2	8

	1992	1991	1990
		(in thousands)	
Revenue			
Full cost of service based rates	$530,599	$475,976	$480,280
Non-full cost of service based rates	109,995	104,947	97,156
Total Industrial	$640,594	$580,923	$577,436

The Company anticipates that non-full cost of service industrial sales and full cost of service industrial sales will remain near the 1992 amounts during 1993; however, the potential exists for loss of additional load in the future to other competitive sources of power, and further pricing below the full cost of service may be necessary to meet competition in order to prevent such loss.

Wholesale Sales. Competition for wholesale sales resulted in the Company and a majority of its wholesale customers reaching agreements during 1989 for rates that were lower than the then existing approved rates for the Company's wholesale electric service and, in some cases, lowered the energy and power requirements from those previously contracted for. The rates agreed to in contracts running until 1996-2000 do not recover the full cost of service.

The city of College Station, Texas ceased purchasing its energy requirements from the Company when its contract expired on December 31, 1991. Non-fuel related revenues from sales to College Station were approximately $11,500,000 and $11,200,000 during 1991 and 1990, respectively.

Operating Expenses and Taxes

Fuel and Purchased Power. Fuel expense increased 6 percent during 1992, when compared to 1991, due to an increase in average fuel cost caused primarily by higher natural gas prices, offset in part by a decreased use of Company-owned generating units.

Fuel expense decreased 2 percent for 1991, when compared to 1990, due to a reduction in the average fuel cost. The reduction in average fuel cost resulted primarily from lower natural gas prices and from greater utilization of lower priced nuclear generation.

Purchased power expense decreased 15 percent for 1992, when compared to 1991, due to the reduction in capacity costs associated with the buyback, which ended in June 1991, of a portion of CEPCO's share of River Bend generation, in addition to a reduction in the cost of kilowatt-hours purchased, offset in part by increased kilowatt-hours purchased.

Purchased power expense decreased 18 percent for 1991, when compared with 1990, due primarily to the reduction in capacity costs associated with the buyback, which ended in June 1991, of a portion of CEPCO's share of River Bend generation, in addition to a reduction in kilowatt-hours purchased during 1991, when compared to 1990.

The cost per kilowatt-hour of fuel consumed and purchased power and the breakdown of electric energy requirements are detailed below:

	1992	1991	1990
Cost of fuel consumed (cents per KWH)			
Natural gas	2.01	1.79	1.91
Coal	1.68	2.08	2.11
Nuclear	1.64	1.24	1.28
Combined	1.93	1.73	1.83
Cost of purchased power (cents per KWH)	2.69	3.97	4.70

	1992	1991	1990
		(kilowatt-hours in thousands)	
Net generation (excluding steam department electric generation)	24,577,833	25,233,164	24,782,548
Purchased power	4,934,937	4,010,461	4,230,143
Total electric energy requirements	29,512,770	29,243,625	29,012,691

	1992	1991	1990
Net generation (excluding steam department electric generation)			
Natural gas	63%	57%	61%
Coal	13	13	11
Nuclear	7	16	13
	83	86	85
Purchased power	17	14	15
Total electric energy requirements	100%	100%	100%

Other Operations and Maintenance Expense. Operations and maintenance expense increased for 1992, when compared to 1991. The increase resulted from additional costs associated with the refueling outage completed in September 1992 at River Bend and other River Bend related projects, as well as increased Company-wide payroll.

As discussed in Note 3 to the Consolidated Financial Statements, the Company made certain repairs and improvements to the service water system and repairs to a feedwater nozzle at River Bend during the refueling outage. These repairs and improvements extended the refueling outage beyond previous outage periods. The Company received a letter from CEPCO dated September 3, 1992, that alleged the operating and maintenance costs for River Bend are far in excess of industry averages and stated their intention to fund a maximum of $700,000 per week under protest during the remainder of 1992, or until CEPCO is satisfied regarding these costs. Due to the Company's funding of CEPCO's share of certain of these repair costs and the funding of CEPCO's share of refueling outage costs in excess of $10,600,000 and of costs in excess of the limited funding by CEPCO proposed by its September 3, 1992 letter, all without waiver of the Company's rights, operations and maintenance expense resulting from these items increased by approximately $14,392,000 during 1992, when compared to 1991.

Operations and maintenance expense increased for 1991, when compared to 1990. The increase resulted from additional payroll costs, and increased outage accruals and maintenance at River Bend.

Taxes. Federal income taxes charged to operating expenses increased in 1992, when compared to 1991, as detailed in Note 5 to the Consolidated Financial Statements. Federal income taxes charged to operating expenses decreased in 1991, when compared to 1990, as detailed in Note 5 to the Consolidated Financial Statements. State income taxes decreased due to the book recognition of tax benefits of state tax net operating loss carryforwards.

Non-Operating Items

Southern Company Settlement and Related Income Taxes. See Note 3 to the Consolidated Financial Statements for a description of the dispute and settlement regarding purchased power contracts with the Southern Company.

Other — Net. Other — net increased for 1992, when compared to 1991. During 1992, the Company reversed $38,100,000 of the common stock guarantee liability to the Southern Company. The liability reversal resulted from an increase in the highest five-day average price of the Company's common stock.

Other — net increased for 1991, when compared to 1990, due to franchise tax refunds the Company was allowed to retain as part of the rate case settlement in Docket No. 8702 in Texas, as discussed in Note 4 to the Consolidated Financial Statements.

Interest Charges. Total interest charges for 1992 decreased, when compared to 1991, despite an increase of approximately $74,000,000 in the average long-term debt outstanding. Interest savings from the refinancing of higher cost debt provided for the reduction of total interest charges, despite the increased levels of long-term debt. The increase in long-term debt was used primarily to pay preference dividend arrearages and to retire all outstanding preference stock, including redemption premiums.

Interest expense on the notes payable to Southern has been classified as long-term interest since the consummation of the settlement in November 1991. Prior to that the interest on the Southern obligations was classified as other interest expense.

Interest charges on long-term debt decreased for 1991, when compared to 1990, due to the net decrease of $133,082,000 of debt during 1991, excluding the notes payable to Southern issued as part of the litigation settlement. This decrease was offset in part due to interest expense on the notes payable to Southern recorded subsequent to the issuance of the notes on November 7, 1991. The Company recorded the notes at the discounted present value on November 7, 1991, and then recorded interest expense on the notes through January 1, 1993.

Interest charges on short-term debt and other increased for 1991, when compared to 1990, due to interest expense accrued on the estimated Southern settlement, recorded prior to the consummation of the settlement.

Extraordinary Items (Net of Income Taxes). Loss on the Extinguishment of Debt. The Company recorded losses on the following debt retirements during 1992:

	Loss on Extinguished Debt	Tax Effect	Net of Tax Loss
	(in thousands)		
January 1992 first mortgage bond retirement	$ 3,046	$1,036	$2,010
May 1992 first mortgage bond retirement	6,463	2,197	4,266
August 1992 pollution control bond retirement	786	267	519
December 1992 first mortgage bond retirement	4,245	1,443	2,802
	$14,540	$4,943	$9,597

Discontinuation of Regulatory Accounting Principles. See Note 4 to the Consolidated Financial Statements for a description of the increase in deferred taxes associated with applying SFAS No. 101 to the deregulated portion of River Bend during 1991.

Cumulative Effect of Accounting Change (Net of Income Taxes). As discussed in Note 4 to the Consolidated Financial Statements, the Company changed the accounting for power plant materials and supplies effective January 1, 1992, and recorded the cumulative effect of the change which increased net income $6,510,000 before related income taxes of $2,543,000.

New Accounting Standards

In February 1992, the FASB issued SFAS No. 109, Accounting for Income Taxes, which significantly changes accounting for income taxes and supersedes almost all existing authoritative accounting literature on accounting for income taxes. SFAS No. 109 revises the computation of deferred income taxes so that the amount of deferred income taxes on the balance sheet is adjusted whenever tax rates or other changes of the income tax law are enacted. SFAS No. 109 also prohibits net of tax accounting and reporting and requires recognition of deferred tax liabilities for tax benefits previously flowed through to ratepayers. Adoption of SFAS No. 109 is required in 1993. The adoption of SFAS No. 109 may be recorded by restating prior years' financial statements or by recording the cumulative effect of the change in the year of adoption. The Company presently plans to record the adoption of SFAS No. 109 by restating 1990, 1991, and 1992 financial statements. Detailed below are the estimated effects on the Company's results of operations and financial position resulting from such restatement:

	1990 As Reported	SFAS No. 109 Effect	1990 As Restated
		(in thousands)	
Income (Loss) Before Extraordinary Items and the Cumulative Effect of Accounting Change	$ (44,282)	$ 7,883	$ (36,399)
Cumulative Effect of the Adoption of SFAS No. 109 on Years Prior to 1990	—	(96,494)	(96,494)
Net Loss	(44,282)	(88,611)	(132,893)
Loss Applicable to Common Stock	(107,024)	(88,611)	(195,635)
Earnings (Loss) Per Average Share of Common Stock Outstanding Before Extraordinary Items and the Cumulative Effect of Accounting Change	(0.99)	0.07	(0.92)
Loss Per Average Share of Common Stock Outstanding	(0.99)	(0.82)	(1.81)
Total Assets	6,863,269	589,510	7,452,779
Total Capitalization and Liabilities (Excluding Retained Earnings)	6,152,632	678,121	6,830,753
Retained Earnings	710,637	(88,611)	622,026

	1991 As Reported	SFAS No. 109 Effect	1991 As Restated
		(in thousands)	
Income Before Extraordinary Items and the Cumulative Effect of Accounting Change	$ 122,449	$ (10,058)	$ 112,391
Net Income	102,283	9,747	112,030
Income Applicable to Common Stock	39,213	9,747	48,960
Earnings Per Average Share of Common Stock Outstanding Before Extraordinary Items and the Cumulative Effect of Accounting Change	0.52	(0.09)	0.43
Earnings Per Average Share of Common Stock Outstanding	0.34	0.09	0.43
Total Assets	6,911,492	557,317	7,468,809
Total Capitalization and Liabilities (Excluding Retained Earnings)	6,164,735	636,181	6,800,916
Retained Earnings	746,757	(78,864)	667,893

	1992 As Reported	SFAS No. 109 Effect	1992 As Restated
		(in thousands)	
Income Before Extraordinary Items and the Cumulative Effect of Accounting Change	$ 133,787	$ 5,691	$ 139,478
Net Income	128,157	5,691	133,848
Income Applicable to Common Stock	78,455	5,691	84,146
Earnings Per Average Share of Common Stock Outstanding Before Extraordinary Items and the Cumulative Effect of Accounting Change	0.74	0.05	0.79
Earnings Per Average Share of Common Stock Outstanding	0.69	0.05	0.74
Total Assets	6,858,494	537,085	7,395,579
Total Capitalization and Liabilities (Excluding Retained Earnings)	6,153,859	610,258	6,764,117
Retained Earnings	704,635	(73,173)	631,462

If the Company elected to not restate prior years' financial statements, the adoption of SFAS No. 109 would result in a charge to net income in the first quarter of 1993 of $73,173,000.

Management believes it is probable that the future increase in taxes payable, resulting from the reversal of tax benefits previously flowed through to customers and other temporary differences, will be recovered from customers through future rates and, therefore, the Company will record a regulatory asset pursuant to SFAS No. 71 upon the adoption of SFAS No. 109, as detailed above. Rate actions of a regulator can reduce or eliminate the value of an asset. If the LPSC or PUCT excludes all or part of the future taxes recorded as a regulatory asset from allowable costs and it is not probable that the regulatory asset will be included as an allowable cost in a future period, the carrying amount of the regulatory asset would be reduced if such assets have been impaired.

SFAS No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions, requires the Company, beginning in 1993, to change the method of accounting for such benefits to the accrual method. The Company estimates that it will have an unrecognized accumulated postretirement benefit obligation of $128,000,000 as of January 1, 1993. The Company has elected to amortize the unrecognized transition obligation over twenty years. Total charges for postretirement benefits under the provisions of SFAS No. 106, including the amortization of the transition obligation, are currently estimated to increase by approximately $15,800,000 in 1993. Amounts ultimately recorded in accordance with SFAS No. 106 will be influenced by, among other things, the actuarial assumptions used by the Company and the regulatory treatment of the costs received by the Company.

The FERC recently established guidelines in order to defer the difference, as a regulatory asset, between the current cash payments and the accrued amounts resulting from SFAS No. 106. Such guidelines include making cash deposits to an irrevocable external trust, filing a rate case seeking inclusion of such costs within three years, and amortizing the regulatory asset over a period not to exceed twenty years beyond the SFAS No. 106 adoption date.

In November 1992, the FASB issued SFAS No. 112, Employers' Accounting for Postemployment Benefits. SFAS No. 112 requires the Company to recognize the obligation for providing such benefits as disability-related benefits, severance benefits, and supplemental unemployment benefits. The adoption of SFAS No. 112 is required in 1994, however, the Company believes the effect of the adoption will be immaterial on the Company's results of operations and financial position.

Consolidated Statement of Income (Loss)

For the years ended December 31
(in thousands except per share amounts)

	1992	1991	1990
Operating Revenue			
Electric	$1,694,536	$1,623,959	$1,596,635
Steam	50,315	46,418	61,052
Gas	28,523	31,858	32,998
	1,773,374	1,702,235	1,690,685
Operating Expenses and Taxes			
Fuel	471,873	446,543	457,503
Purchased power	136,716	161,374	197,764
Other operations	293,948	267,592	256,951
Maintenance	161,080	142,098	131,775
Depreciation and amortization	188,393	187,936	186,451
Deferred revenue requirement — River Bend phase-in plan	2,290	5,575	(41,515)
Amortization of deferred River Bend costs	50,656	32,661	21,631
Income Taxes			
Federal	43,833	39,140	46,640
State	(1,257)	(15,066)	11,323
Other taxes	91,740	88,402	88,929
	1,439,272	1,356,255	1,357,452
Operating Income	334,102	345,980	333,233
Other Income and Deductions			
Allowance for equity funds used during construction	1,226	608	640
Southern Company settlement	—	—	(205,015)
Southern Company settlement related income taxes	—	—	80,834
Other — net	45,928	35,829	21,513
Income Before Interest Charges	381,256	382,417	231,205
Interest Charges			
Long-term debt	239,341	234,418	259,186
Short-term debt and other	9,075	26,038	16,811
Allowance for borrowed funds used during construction	(947)	(488)	(510)
	247,469	259,968	275,487
Income (Loss) Before Extraordinary Items and the Cumulative Effect of Accounting Change	133,787	122,449	(44,282)
Extraordinary Items (net of income taxes) (Note 4)	(9,597)	(20,166)	—
Cumulative Effect of Accounting Change (net of income taxes) (Note 4)	3,967	—	—
Net Income (Loss)	128,157	102,283	(44,282)
Dividends on Preferred and Preference Stock	49,702	63,070	62,742
Income (Loss) Applicable to Common Stock	$ 78,455	$ 39,213	$ (107,024)
Average Shares of Common Stock Outstanding	114,055	114,055	108,055
Earnings (Loss) Per Average Share of Common Stock Outstanding Before Extraordinary Items and the Cumulative Effect of Accounting Change	$ .74	$ .52	$ (.99)
Earnings (Loss) Per Average Share of Common Stock Outstanding	$ .69	$ .34	$ (.99)
Dividends Per Share of Common Stock	$ —	$ —	$ —

The accompanying notes are an integral part of the consolidated financial statements.

Consolidated Statement of Cash Flows
For the years ended December 31
(in thousands)

	1992	1991	1990
Operating Activities			
Net income (loss)	**$ 128,157**	$102,283	$ (44,282)
Adjustments to reconcile net income (loss) to net cash from operating activities:			
Provision for rate refund — Louisiana	**(12,988)**	24,143	—
Deferred fuel and purchased power expense — net	**4,483**	23,374	1,899
Amortization of nuclear fuel	**18,580**	42,172	35,454
Depreciation and amortization	**192,749**	187,521	188,885
Deferred River Bend expenses and revenue requirement	**2,290**	5,575	(41,515)
Amortization of accumulated deferred River Bend costs	**50,656**	32,661	21,631
Deferred income taxes — net	**57,477**	36,540	(16,169)
Investment tax credits — net	**(2,200)**	(4,308)	(4,286)
Allowance for funds used during construction	**(2,173)**	(1,096)	(1,150)
Southern Company settlement	**(20,797)**	12,565	213,885
Extraordinary items (net of income taxes)	**9,597**	20,166	—
Cumulative effect of accounting change (net of income taxes)	**(3,967)**	—	—
Other	**(24,204)**	(19,022)	16,439
Changes in:			
Receivables	**4,373**	(12,503)	(1,897)
Fuel inventories	**(4,152)**	10,422	(3,155)
Materials and supplies	**(2,254)**	(146)	(919)
Prepayments and other current assets	**6,969**	(9,825)	2,173
Accounts payable — trade	**(1,171)**	(6,912)	9,959
Customer deposits	**996**	1,258	1,031
Taxes accrued	**(2,634)**	753	(1,601)
Interest accrued	**(15,276)**	3,211	(10,927)
Other current liabilities	**(19,386)**	21,315	(1,667)
Net cash flow provided by operating activities	**365,125**	470,147	363,788
Financing Activities			
Issuance of long-term debt	**1,248,965**	200,000	—
Discount and expense on long-term debt	**(14,740)**	—	—
Payment of deferred River Bend construction commitments	**—**	(12,429)	(15,437)
Payment of lease obligations	**(18,544)**	(36,890)	(44,110)
Retirement of long-term debt	**(1,124,863)**	(320,653)	(202,654)
Redemption premiums on long-term debt	**(70,015)**	—	—
Retirement of preferred and preference stock	**(155,926)**	—	—
Redemption premiums on preference stock	**(18,300)**	—	—
Payment of preferred and preference dividends	**(237,369)**	(127,398)	—
Net cash flow used by financing activities	**(390,792)**	(297,370)	(262,201)
Investing Activities			
Construction expenditures	**(97,377)**	(87,470)	(73,020)
Sale of utility plant	**12,460**	—	—
Allowance for funds used during construction	**2,173**	1,096	1,150
Refund of (deposit to) escrow account	**18,831**	(2,975)	(11,463)
Other property and investments	**(5,740)**	13,045	(19,184)
Net cash flow used by investing activities	**(69,653)**	(76,304)	(102,517)
Net change in cash and cash equivalents	**(95,320)**	96,473	(930)
Cash and cash equivalents at January 1	**293,061**	196,588	197,518
Cash and cash equivalents at December 31	**$ 197,741**	$293,061	$196,588
Supplemental Cash Flow Disclosure			
Cash paid during the period for:			
Interest	**$ 239,607**	$227,306	$267,529
Income taxes	**8,000**	5,700	6,359
Increase in nuclear fuel lease obligations	**18,074**	13,958	24,623
Increase in gas storage lease	**68,948**	—	—

The accompanying notes are an integral part of the consolidated financial statements.

Consolidated Balance Sheet
December 31
(in thousands)

	1992	1991
Assets		
Utility and Other Plant, at original cost		
Plant in service	$6,970,683	$6,873,767
Less: Accumulated provision for depreciation	2,172,719	2,024,351
	4,797,964	4,849,416
Construction work in progress	32,305	36,538
Nuclear fuel, net of accumulated amortization	106,565	107,071
	4,936,834	4,993,025
Other Property and Investments	36,225	50,200
Current Assets		
Cash and cash equivalents	197,741	293,061
Receivables		
Customers	124,214	121,897
Other	18,405	25,095
Fuel inventories	21,159	17,007
Materials and supplies (Note 4)	86,972	8,097
Prepayments and other	38,314	45,283
	486,805	510,440
Deferred Charges and Other Assets		
Accumulated deferred income taxes	179,985	190,438
Deferred River Bend costs	814,263	891,568
Other	404,382	275,821
	1,398,630	1,357,827
	$6,858,494	$6,911,492
Capitalization and Liabilities		
Capitalization (See Statement of Capitalization)		
Common shareholders' equity (Note 4)	$1,972,874	$2,021,673
Preference stock	—	100,000
Preferred Stock		
Not subject to mandatory redemption	136,444	136,444
Subject to mandatory redemption	254,570	362,580
Long-term debt	2,374,458	2,293,982
	4,738,346	4,914,679
Current Liabilities		
Long-term debt due within one year	160,000	94,003
Preferred stock and long-term debt sinking fund requirements	15,242	52,205
Accounts payable — trade	101,513	102,684
Customer deposits	21,152	20,156
Taxes accrued	19,092	21,726
Interest accrued	62,013	77,289
Capital leases — current	51,688	21,328
Southern Company settlement	9,300	—
Other	65,025	75,718
	505,025	465,109
Deferred Credits and Other Liabilities		
Investment tax credits	94,690	96,889
Accumulated deferred income taxes	852,302	807,678
Capital leases — non-current	154,923	116,805
Deferred River Bend financing costs	131,123	155,482
Southern Company settlement	—	47,400
Other	382,085	307,450
	1,615,123	1,531,704
Commitments and Contingencies (Note 3)		
	$6,858,494	$6,911,492

The accompanying notes are an integral part of the consolidated financial statements.

Consolidated Statement of Capitalization
December 31
(in thousands)

			1992	1991
Common Shareholders' Equity				
Common Stock				
Authorized 200,000,000 shares without par value				
Outstanding 114,055,065 shares			**$1,200,923**	$1,200,923
Premium and expense on capital stock			**(10,535)**	(4,155)
Other paid-in capital			**77,851**	78,148
Retained earnings (Note 4)			**704,635**	746,757
			1,972,874	2,021,673
Preference Stock				
Authorized 20,000,000 shares, without par value, cumulative				
4,000,000 shares outstanding at December 31, 1991				
Dividend Series	**Shares Outstanding December 31, 1992**	**Redemption Price as of December 31, 1992**		
$ 4.40	—	$ —	—	50,000
3.85	—	—	—	50,000
			—	100,000
Preferred Stock				
Authorized 6,000,000 shares, $100 par value, cumulative				
Outstanding 4,058,311 and 4,617,568 shares				
Dividend Series	**Shares Outstanding December 31, 1992**	**Redemption Price as of December 31, 1992**		
Not subject to mandatory redemption				
$ 4.40	51,173	$ 108.00	**5,117**	5,117
4.50	5,830	105.00	**583**	583
4.40—1949	1,655	103.00	**166**	166
4.20	9,745	102.818	**975**	975
4.44	14,804	103.75	**1,480**	1,480
5.00	10,993	104.25	**1,099**	1,099
5.08	26,845	104.63	**2,685**	2,685
4.52	10,364	103.57	**1,056**	1,056
6.08	32,829	103.34	**3,283**	3,283
7.56	350,000	101.80	**35,000**	35,000
8.52	500,000	102.43	**50,000**	50,000
9.96	350,000	104.64	**35,000**	35,000
			136,444	136,444
Subject to mandatory redemption				
$ 8.80	260,275	103.00	**26,027**	30,103
9.75	24,598	103.00	**2,460**	2,963
8.64	224,000	103.00	**22 400**	30,247
11.48	340,000	103.00	**34,000**	48,000
13.64	—	—	—	4,000
12.92	510,000	105.00	**51,000**	60,000
11.50	712,500	105.00	**71,250**	75,000
Adjustable rate—Series A	240,000	103.00	**24,000**	30,000
Adjustable rate—Series B	382,500	103.00	**38,250**	45,000
Preferred dividends in arrears			—	80,477
			269,387	405,790
Preferred stock sinking fund requirements			**(14,817)**	(43,210)
			254,570	362,580

(Statement continued on following page.)

	1992	1991
Long-Term Debt		
First mortgage bonds		
Maturing 1993 through 1997—		
16.8% due September 23, 1993	—	17,150
13¾% due March 1, 1994	—	100,000
5% due January 1, 1996	20,000	20,000
6.67% due November 1, 1996	75,000	—
5⅝% due February 1, 1997	35,000	35,000
6.99% due November 1, 1997	75,000	—
Maturing 1998 through 2002—6⅝% through 8.21%	510,000	210,000
Maturing 2003 through 2007—8¼% through 10.15%	530,000	270,000
Maturing 2008 through 2012—10⅛% through 15%	—	325,000
Maturing 2013 through 2017—11⅜% through 13½%	—	500,000
8.94% due January 1, 2022	150,000	—
8.70% due April 1, 2024	300,000	—
First mortgage bond sinking fund requirement	—	(8,570)
	1,695,000	1,468,580
Pollution control and industrial development bonds		
7% due 2006	24,575	25,000
5.9% due 2007	23,000	23,000
6.75% and 10⅜% due 2012	48,285	48,285
9½% due 2013	17,450	17,450
10⅝% due 2014	50,000	50,000
12% due 2014	52,000	52,000
7.7% due 2014	94,000	94,000
7½% due 2015	41,600	—
7% due 2015	39,000	—
Variable rate due 2015	28,400	109,000
9% due 2015	45,000	45,000
Variable rate due 2016	20,000	20,000
Pollution control and industrial development bond sinking fund requirements	(425)	(425)
Debentures—due 1998—9.72%	200,000	200,000
Notes payable—Southern Company	—	142,697
Other long-term debt	2,718	2,038
	2,380,603	2,296,625
Unamortized premium and discount on debt—net	(6,145)	(2,643)
	2,374,458	2,293,982
	$4,738,346	$4,914,679

The accompanying notes are an integral part of the consolidated financial statements.

Consolidated Statement of Changes in Capital Stock and Retained Earnings
For the years ended December 31
(in thousands)

	Preference Stock	Preferred Stock Subject to Mandatory Redemption	Common Stock	Premium and (Expense) on Capital Stock	Other Paid-In Capital	Retained Earnings
Balance: January 1, 1990	$ 100,000	$414,651	$1,195,148	$ (3,936)	$26,173	$ 789,965
Net loss — 1990						(44,282)
Preferred stock sinking fund requirements		(11,066)				
Dividends in arrears on preferred stock subject to mandatory redemption		35,046				(35,046)
Balance: December 31, 1990	100,000	438,631	1,195,148	(3,936)	26,173	710,637
Net income — 1991						102,283
Issuance of common stock: Southern Company settlement (6,000,000 shares)			5,775	(200)	51,975	
Preferred stock sinking fund requirements		(14,816)				
Dividends in arrears on preferred stock subject to mandatory redemption		35,374				(35,374)
Dividends declared on preferred stock		(96,609)				(30,789)
Capital stock expense				(19)		
Balance: December 31, 1991	100,000	362,580	1,200,923	(4,155)	78,148	746,757
Net income — 1992						128,157
Dividends declared on preferred and preference stock		(80,477)				(158,547)
Preferred stock sinking fund requirements		(27,533)				
Preferred and preference stock redemption	(100,000)			(6,373)	(297)	(11,732)
Capital stock expense				(7)		
Balance: December 31, 1992	$ —	$254,570	$1,200,923	$(10,535)	$77,851	$ 704,635

The accompanying notes are an integral part of the consolidated financial statements.

Gulf States Utilities Company Notes to the Consolidated Financial Statements

1. Summary of Significant Accounting Policies

System of Accounts. The accounting records of the Company are maintained in accordance with the Uniform System of Accounts as prescribed by the Federal Energy Regulatory Commission (FERC) and adopted by the Louisiana Public Service Commission (LPSC) and the Public Utility Commission of Texas (PUCT).

Utility Plant and Depreciation. Utility and other plant is stated at original cost when first dedicated to public service. Costs of repairs and minor replacements are charged to expense as incurred. The original cost of depreciable utility plant retired and cost of removal, less salvage, are charged to accumulated provision for depreciation. The provision for depreciation is computed using the straight-line method at rates, approved by the regulatory commissions, which will amortize the unrecovered cost of depreciable plant over the estimated remaining service life.

Composite depreciation rates were as follows:

	1992	1991	1990
Electric	2.68%	[illegible]	[illegible]
Steam	4.23	[illegible]	[illegible]
Gas	3.53	3.53	[illegible]
Total Company	2.71	2.70	2.72

Decommissioning. The Company is accruing the decommissioning costs of River Bend in accordance with the regulatory commissions' orders over a 38 to 40-year period.

Allowance for Funds Used During Construction (AFUDC) and Capitalization of Interest. The accrual of AFUDC is a utility accounting practice calculated under guidelines prescribed by the FERC and capitalized as part of the cost of utility plant representing the cost of servicing the capital invested in construction work in progress (CWIP). Such AFUDC has been segregated into two component parts — borrowed and equity funds. That portion allocated to borrowed funds is reflected as an adjustment to interest charges, while that portion applicable to equity funds is shown as a source of other income. Both the equity and the borrowed portions of AFUDC are non-cash items which have the effect of increasing the Company's reported net income. When the related utility plant is placed in service, a return on and recovery of prudently incurred costs have been permitted by regulators in determining the rates charged for utility service.

In 1987, due to the construction interest capitalization provisions of the Tax Reform Act of 1986, the Company began accruing AFUDC at pre-tax rates. These rates were as follows:

January 1, 1990 - March 31, 1990	11.75%
April 1, 1990 - March 31, 1991	11.50
April 1, 1991 - March 31, 1992	11.75
April 1, 1992 - December 31, 1992	10.75

Revenue, Fuel, and Purchased Power. The Company records revenue as billed to its customers on a cycle billing basis. Revenue is not recorded for energy delivered and unbilled at the end of each fiscal period. The Company's wholesale and Louisiana retail rate schedules provide for adjustments to substantially all rates for increases or decreases in the costs of fuel for generation, purchased power, and gas distributed. The Company's Texas retail rate schedules include a fixed fuel factor approved by the PUCT, which remains the same until changed as part of a general rate case or fuel reconciliation, or until the PUCT orders a reconciliation for any over or under collections of fuel cost. Reconcilable fuel and purchased power costs in excess of those included in base rates or recovered through fuel adjustment clauses are deferred (or accrued) until such costs are billed (or credited) to customers.

Inventories. The Company's fuel inventories are comprised of fuel oil and natural gas, valued at weighted average cost, and coal, valued at last-in, first-out cost. Materials and supplies are valued at weighted average cost.

Income Taxes. The Company and its subsidiaries file a consolidated federal income tax return. Income taxes are allocated to the individual companies based on their respective taxable income or loss and investment tax credits, subject to the limitations, for recognition of net operating loss carryforwards and investment tax credits.

The Company follows a policy of comprehensive interperiod income tax allocation where such treatment is permitted for ratemaking purposes by regulatory bodies. Deferred income taxes result from timing differences in the recognition of revenue and expenses for tax and accounting purposes.

Investment tax credits have been deferred and are being amortized ratably over the useful lives of the related property.

See Note 4 for information regarding a change in accounting for income taxes in 1993.

Subsidiary Companies. The Company accounts for the operations and financial position of its wholly-owned subsidiary companies, Varibus Corporation (Varibus), Prudential Oil and Gas, Inc. (Prudential), and GSG&T, Inc. (GSG&T) on a consolidated basis.

Consolidated Statement of Cash Flows. For the purposes of the Statement of Cash Flows, the Company considers all highly liquid investments with original maturities of three months or less to be cash equivalents.

Unamortized Project Cancellation Costs. During 1984, the Company began amortizing the cost of the River Bend Unit 2 cancellation applicable to its Texas retail operations over 15 years. In 1989, the Company began amortizing the cost of the River Bend Unit 2 cancellation applicable to the Louisiana retail jurisdiction over 10 years.

2. Proposed Entergy Corporation (Entergy)/Gulf States Utilities Company Business Combination

After negotiations with respect to merger opportunities available, the Board of Directors determined at a meeting on June 5, 1992, that it would be in the best interests of the shareholders and the Company to enter into an Agreement and Plan of Reorganization, dated as of June 5, 1992, between Entergy and the Company (Reorganization Agreement).

The Reorganization Agreement provides for the combination of the two companies in a transaction in which the holders of common stock of the Company would receive at closing, at their election, either shares of common stock of a new holding company or cash, subject to a limitation of $250,000,000 (less the amount payable for fractional shares) on the aggregate amount of cash available for such electing shareholders. If elections for cash exceed such amount, provisions are made for proration of the available cash. The new holding company would in turn become owner of all the outstanding common stock of the Company and would also own all of the common stock of or be successor to Entergy. Under the Reorganization Agreement, the common shareholders of the Company would receive at closing a number of holding company common shares or amount of cash equivalent to $20.00 per share of the common stock of the Company, less the aggregate amount per share of any dividends on the Company's common stock declared between June 5, 1992 and the consummation of the transaction. In addition, if the transaction were consummated after June 5, 1994, the price per common share would increase by an amount representing a proportional amount of the dividends that had been declared on the outstanding common stock of Entergy after such date through the date of closing but in no event less than $0.25 per share per quarter.

The Board received an opinion from its financial adviser, Goldman, Sachs & Co., to the effect that the proposed consideration would be fair to the common shareholders of the Company.

The preferred stock, first mortgage bonds, and other securities of the Company which are outstanding at closing will remain outstanding securities of the Company.

On December 17, 1992, the common shareholders of the Company and of Entergy approved the proposed transaction at special shareholders meetings. In addition, the transaction is subject to certain conditions, including among others, the receipt of necessary orders or other actions by the PUCT, the LPSC, the FERC, the Nuclear Regulatory Commission (NRC), the Securities and Exchange Commission, and clearance under applicable federal anti-trust statutes. The transaction will also be subject to receipt of other necessary consents and approvals, the absence of material adverse developments prior to closing, receipt of appropriate assurance that the transaction will be treated as a tax-free transaction to the extent of shares of the new holding company received by shareholders of the Company, and other customary conditions.

The transaction is also subject to certain rights of termination by each party, including, among others, rights of termination in the event that required regulatory action is denied or not received within a stated period of time or certain other conditions are not satisfied. In the event of termination, provisions are made for certain fees and expenses to be paid by one party to the other, depending upon the circumstances. In certain events, if the transaction is terminated, the Company will be required to pay a significant sum to Entergy if the Company enters into a similar transaction with another party within twelve months after termination.

The Reorganization Agreement provides the Company the right to continue to operate its business in the ordinary and usual course in a manner consistent with past practice and sound utility practice and in which an independent public company would conduct its business and operations. While certain limitations are imposed upon interim actions of the Company, such as a limitation upon the amount of common dividends payable during the period prior to consummation of the business combination, the Company believes that the rights reserved to it to operate its business and continue its financing program are adequate to enable the Company to pursue those courses of action it presently expects to be appropriate during the pendency of the regulatory process.

Due to the requirement of numerous regulatory actions which could take until at least late 1993 or early 1994, the risk of intervening material adverse events, and other numerous conditions and rights of termination, there can be no assurance that the proposed business combination agreed upon will be consummated.

In June 1992, three complaints were filed in a district court seeking class action on behalf of all persons owning common stock of the Company. The complaints allege, among other things, that the merger offer price was below recent estimates of a merger price and that the Company's directors breached their fiduciary duties. Management believes these actions are without merit, and the Company intends to oppose them vigorously.

3. Commitments and Contingencies

Financial Condition. Although the Company received partial rate relief relating to its River Bend Unit 1 (River Bend) nuclear unit, the Company's financial position was strained from 1986 to 1990 by its inability to earn a return on and fully recover its investment and other costs associated with River Bend. The Company's financial position has continued to improve; however, issues to be finally resolved in PUCT rate proceedings and appeals thereof, combined with the application of accounting standards, may result in substantial write-offs and charges that could result in substantial net losses being reported in 1993, and subsequent periods, with resulting substantial adverse adjustments to common shareholders' equity. Future earnings will continue to be adversely affected by the lack of full recovery and return on the investment and other costs associated with River Bend.

Southern Company (Southern). Beginning in 1986, the Company and Southern litigated disputes relating to certain purchase power contracts providing for purchases by the Company of capacity and energy from Southern.

SETTLEMENT. On November 7, 1991, the Company and Southern consummated a settlement of the long-standing litigation in accordance with the terms and provisions of a previous settlement agreement executed as of December 21, 1990. In 1990, the Company recorded a charge to earnings of $205,015,000 before the related income tax benefits of $80,834,000 (which includes $11,129,000 of state tax benefits) representing management's estimate of the settlement costs. Due to the state net operating loss position the Company is in, an offsetting state tax expense of $11,129,000 was included in "Income Taxes — State" in 1990.

In accordance with the settlement agreement, during 1991 Southern received the following:

(a) approximately $75,000,000 plus interest earned since August 31, 1990, which includes all funds previously deposited by the Company in a court-controlled escrow account in lieu of certain payments under the purchase power contracts and the interest earned thereon (the Company paid approximately $6,590,000 in addition to the escrow funds);

(b) $160,000,000 non-interest bearing promissory notes due on January 1, 1993, subject to the Company having "adequate cash" at January 1, 1993, as described below;

(c) 6,000,000 shares of the Company's common stock, which Southern will have the right to vote only in the event of bankruptcy of or default by the Company (at December 31, 1992, Southern owned a total of 3,157,600 shares, registered as holders of record and held by nominee); and

(d) $9,300,000, determined based on a common stock price differential agreement, due January 1, 1993, subject to the Company having "adequate cash" at January 1, 1993, as discussed below.

Pursuant to the settlement agreement, the Company would be deemed to have "adequate cash" at the time it declares or pays cash dividends on its outstanding common stock or to the extent its projected minimum available cash balance each year exceeds $35,000,000.

On January 4, 1993, the Company paid Southern $111,329,000 to retire promissory notes and paid $6,471,000 under the common stock price differential agreement. The unpaid $48,671,000 of promissory notes and $2,829,000 of the common stock price differential will accrue interest at the prime rate plus 1 percent and is payable on the earlier of the January 1st as of which the Company has "adequate cash" or January 1, 1999, or earlier at the Company's discretion upon five days notice.

The Company's obligations under the settlement are secured by a first mortgage lien on the Lewis Creek generating station, a 532 megawatt gas-fired facility owned by GSG&T, and a pledge of the common stock of GSG&T.

Cajun Electric Power Cooperative, Inc. (CEPCO). The Company has significant business relationships with CEPCO, including co-ownership of River Bend and Big Cajun 2 Unit 3. The Company and CEPCO own 70 percent and 30 percent of River Bend, respectively, while Big Cajun 2 Unit 3 is owned 42 percent and 58 percent by the Company and CEPCO, respectively.

On June 26, 1989, CEPCO filed a civil action against the Company in the U. S. District Court for the Middle District of Louisiana. CEPCO stated in its complaint that the object of the suit is to annul, rescind, terminate, and/or dissolve the Joint Ownership Participation and Operating Agreement entered into on August 28, 1979 (Operating Agreement) related to River Bend because of fraud and error by the Company, breach of its fiduciary duties owed to CEPCO, and/or the Company's repudiation, renunciation, abandonment, or dissolution of its core obligations under the Operating Agreement, as well as the lack or failure of cause and/or consideration for CEPCO's performance under the Operating Agreement. The suit seeks to recover at least CEPCO's alleged $1.6 billion investment in the unit as damages, plus attorneys' fees, interest, and costs. On March 31, 1992, the district court appointed a mediator to engage in settlement discussions and to schedule settlement conferences between the parties. Discussions with the mediator began in July 1992, however, the Company cannot predict what effect, if any, such discussions will have on the timing or outcome of the case. A trial date has not been set. Two member cooperatives of CEPCO have brought an independent action to declare the River Bend ownership agreement void, based upon failure to get prior LPSC approval alleged to be necessary.

The Company believes the suits are without merit and is contesting them vigorously. No assurance can be given as to the outcome of this litigation. If the Company were ultimately unsuccessful in this litigation and were required to make substantial payments, the Company would probably be unable to make such payments and would probably have to seek relief from its creditors under the Bankruptcy Code.

The Company has been informed that CEPCO has had serious financial problems but that the Rural Electrification Administration (REA) has restructured CEPCO's outstanding debt. Additionally, one of CEPCO's member cooperatives has previously filed for bankruptcy. CEPCO's weak financial condition or its bankruptcy could have significant adverse effects on the Company, including, but not limited to, possible NRC action with respect to the operation of River Bend and a need to bear additional costs associated with the co-owned facilities. During 1993, and for the next several years, it is expected that CEPCO's share of River Bend-related costs will be in the range of $60,000,000 to $75,000,000 per year. If the Company were required to fund CEPCO's share of costs, it would expend cash that would otherwise be available for other uses, and there can be no assurance that such payments could be recovered.

In July 1992, CEPCO notified the Company of its intent to only fund up to approximately $10,600,000 of costs related to the fourth refueling outage at River Bend, completed in September 1992. The Company believes that CEPCO is obligated to pay its full share of such costs under the terms of the applicable contract.

CEPCO has not funded its share of the costs associated with certain repairs and improvements to the service water system and repairs to a feedwater nozzle at River Bend completed during the refueling outage. The Company is paying the costs associated with such repairs and improvements without waiving any rights against CEPCO. The Company believes that CEPCO is obligated to pay its share of such costs under the terms of the applicable contract. CEPCO has filed a suit seeking a declaration that it does not owe such funds and seeking injunctive relief against the Company. The Company is contesting such suit and is reviewing its available legal remedies.

On September 4, 1992, the Company received a letter from CEPCO (dated September 3, 1992) alleging that the operating and maintenance costs for River Bend are "far in excess of industry averages" and that "it would be imprudent for CEPCO to fund these excessive costs." CEPCO further stated that until it is satisfied regarding the costs, it would fund a maximum of $700,000 per week under protest for the remainder of 1992. The Company believes that CEPCO's allegations are without merit and is considering its legal and other remedies available with respect to the underpayments by CEPCO. The total resulting from CEPCO's failure to fund the service water and feedwater repair projects, CEPCO's funding limitation on the fourth refueling outage, and the weekly funding limitation by CEPCO was $28,400,000 as of December 31, 1992.

The Company and CEPCO are parties to FERC proceedings regarding certain longstanding disputes relating to transmission service charges. Hearings before the FERC were completed in December 1988. On May 11, 1989, an administrative law judge issued an initial decision. On April 10, 1992, the FERC issued a final order that affirmed the ruling of the administrative law judge in part, reversed the ruling in part and also denied an earlier request for rehearing by the Company in a related docket (No. ER88-477-000). In May 1992, both the Company and CEPCO filed motions for rehearings which are pending consideration by the FERC. On June 8, 1992, the Company also filed a petition for review in the United States Court of Appeals, regarding certain of the issues decided by the FERC in Docket No. ER88-477-000. The FERC order as issued does not state an amount found to be payable by one party to the other. Based on certain assumptions, the Company interprets the order to mean that CEPCO owes the Company approximately $900,000. The Company estimates that if it prevails on the items appealed in its motion for rehearing and on the items appealed in its petition for review before the Court of Appeals, CEPCO would owe the Company approximately $107,000,000. If CEPCO were to prevail on the items appealed in its motion for rehearing and the Company were to not prevail in its appeal to the courts, the Company estimates, based on certain assumptions and limited data from CEPCO, it would owe CEPCO approximately $46,000,000. The interpreted amounts are exclusive of a $7,300,000 payment by CEPCO on December 31, 1990. In a letter agreement dated December 20, 1990, the parties agreed that while the $7,300,000 payment was to be applied to the disputed transmission service charges, the Company's and CEPCO's positions at the FERC would remain unaffected by the $7,300,000 payment. Pending the FERC's ruling on the May 1992 motions for rehearing the Company has continued to bill CEPCO utilizing the historical billing methodology and has booked underpaid transmission charges, including interest, in the amount of $122,872,000 as of December 31, 1992. Such amount was recorded on the balance sheet as a long-term account receivable, which is included in "Deferred Charges and Other Assets—Other" and an offsetting amount in dispute, which is included in "Deferred Credits and Other Liabilities —Other" with no effect on net income.

Nuclear Risks. Ownership and operation of a nuclear generating unit subjects the Company to significant special risks. The Company is insured to an extent as to its interest in River Bend for property damage and decontamination, liability to employees and third parties, and incremental replacement power costs, as described below. However, potential liabilities to which the Company may be subject, including but not limited to liabilities relating to the release or escape of hazardous substances into the environment, may not be insurable, and the amount of insurance carried as to the various risks may not be sufficient to meet potential liabilities and losses. While the Company carries insurance, the availability, amount, and coverage thereof is limited and may become more limited in the future. The available insurance will not cover all types or amounts of loss which may be experienced in connection with the ownership and operation of River Bend. Although the Company has no reason to anticipate a serious nuclear incident at River Bend, if such an incident did occur, it could have a material but presently undeterminable adverse effect on the Company's financial position.

Public liability in case of a nuclear incident at any licensed nuclear facility in the United States is currently limited to $7.8 billion under provisions of the Price-Anderson Act (Act) which was renewed and revised in 1988, and extends through August 1, 2002. The Company insures River Bend for this exposure through a combination of private insurance and the industry-wide secondary financial program. The changes to the Act necessitated modifications to the secondary financial protection, such that the Company will be subjected to a potential retrospective assessment of approximately $66,150,000 per incident with a maximum amount of $10,000,000 per incident payable in any one year for losses in the event of a nuclear incident at its facility or any other licensed nuclear reactor facility in the United States. The 1988 revision to the Act also states that the NRC shall adjust the potential retrospective assessment not less than once each five year period in accordance with the aggregate percentage change in the Consumer Price Index. The adjustment must be completed by August 1993. At this time, the Company does not know what the amount of the adjusted potential retrospective assessment will be. Any retrospective assessments pertaining to this liability are subject to the 70/30 percent ownership interest in River Bend between the Company and CEPCO.

The Company maintains $500,000,000 primary property damage insurance and $800,000,000 of excess insurance for River Bend from the private insurance market. Additionally, the Company has acquired $1,325,000,000 of excess property insurance coverage on River Bend through participation in the Nuclear Electric Insurance Limited (NEIL) II program, with $250,000,000 of this NEIL II policy designated to cover decommissioning liability instead of property damage. Under NEIL II, the Company is subject to a maximum assessment of approximately $13,000,000 in any one policy year. Although the Company has continued to increase the limits of such insurance as capacity becomes available, no assurance can be given about the adequacy of such insurance limits in the event of a major accident. The property damage insurance policy limits are substantially less than the replacement cost of the River Bend facilities.

The NRC has adopted a rule applicable to nuclear generating facilities which establishes an overriding priority and requires, in substance, that if there were an accident at River Bend's reactor and the estimated costs of stabilizing and decontaminating the reactor exceed $100,000,000, the proceeds must first be dedicated to such purposes. The Company's policies on such property have been endorsed to comply with such rule. This has the effect of reducing the amount of proceeds which would be available to repair, replace, or restore the property or otherwise be available for mortgages, trustees, and other loss payees.

The Company maintains a Nuclear Workers' Liability policy which covers liability for tort claims by on-site workers first employed at a nuclear facility after January 1, 1988, for non-catastrophic nuclear-related injury such as the exposure to long-term, low-level radiation. Nuclear-related claims by workers employed in a nuclear facility prior to January 1, 1988, will continue to be covered under the Nuclear Energy Liability policy provided the claim is made by December 31, 1997. Under the Nuclear Workers' Liability policy, the Company is subject to a maximum retrospective premium assessment of approximately $3,159,000.

Some extra expense for River Bend replacement power is insured through the NEIL I program. Under the NEIL I program, the Company is subject to a maximum annual retrospective assessment of approximately $1,299,000.

Disposal of Spent Nuclear Fuel and Nuclear Decommissioning. As provided in the Nuclear Waste Policy Act of 1982, the Company has entered into contracts with the United States Department of Energy (DOE) for disposal of spent nuclear fuel from River Bend. The Company pays a quarterly fee to the DOE equal to one mill per net kilowatt-hour generated by River Bend. The Company is currently recovering such costs in all jurisdictions.

The Company has received approval from the PUCT, LPSC, and FERC to collect in rates amounts necessary to decommission River Bend when it reaches the end of its service life. Decommissioning costs are subject to the 70/30 percent ownership interest in River Bend between the Company and CEPCO. To provide for the Company's share of future decommissioning costs, the amounts collected through rates from customers are placed in a master trust fund, which is estimated to provide, with earnings, sufficient funds to decommission the plant at the end of its estimated service life. Contributions, most of which qualify under Section 468A of the Internal Revenue Code as an annual tax deduction, were derived from a site-specific engineering study of the cost to decommission River Bend, which is estimated to be $206,000,000 in 1992 dollars. A more recent 1991 engineering study, which has not yet been entered into Company rates and used as a basis of funding, indicates decommissioning costs may be $290,000,000 in 1992 dollars. The Company feels that recent changes in the laws will tend to allow annual contributions to the trust to remain at current levels of funding and offset or mitigate the increase in decommissioning costs, as indicated in the 1991 engineering study. At December 31, 1992, the balance in the decommissioning trust fund was $14,102,000. There can be no assurance that the amount being provided for will be adequate.

The National Energy Bill, which was signed into law in October 1992, established a Uranium Enrichment Decontamination and Decommissioning Fund (Fund) in order to decontaminate and decommission older facilities engaged in the enrichment of nuclear fuels. The Fund will in part be funded by annual assessments to utilities based on past enrichment services provided to the utilities. The Company is currently unsure as to the amount it will be assessed, but current estimates indicate that the Company's share could be in the range of $650,000 annually. The National Energy Bill stated that any assessments levied for decontamination and decommissioning of enrichment facilities shall be deemed a necessary and reasonable current cost of fuel and shall be fully recoverable in rates in the same manner as the utility's other fuel costs.

Dividend Matters

PREFERRED STOCK. On March 15, 1992, the Company paid $115,692,000 of preferred stock dividends and on April 2, 1992, paid $30,643,000 of preferred stock sinking fund requirements. With those payments, the Company became current and has since continued to stay current with respect to all preferred stock dividend and sinking fund requirements.

PREFERENCE STOCK. In February 1987, the Board of Directors omitted dividends on the Company's preference stock to have been payable in March 1987. The Company continued to omit preference dividends through April 1992. On April 24, 1992, the Board of Directors authorized a portion of the proceeds from a sale of first mortgage bonds, together with cash from other sources, to be used to pay cumulative preference stock dividend arrearages and redeem the outstanding preference stock, including redemption premiums. On June 4, 1992, the Company paid $90,340,000 of preference stock dividend arrearages and accrued dividends, and redeemed $100,000,000 of outstanding preference stock, plus redemption premiums of $18,300,000.

COMMON STOCK. At its meeting in August 1986, the Board of Directors omitted any dividend on the common stock of the Company to have been payable in September 1986. No dividend on common stock has been declared since then. Under the terms of its short-term bank credit agreement discussed in Note 11, the Company is restricted from paying dividends on its common stock. The Company's ability to declare and pay dividends is also restricted by provisions of its Restated Articles of Incorporation (Articles), the Mortgage Indenture, the Reorganization Agreement with Entergy, and state and federal law.

The Company's ability to pay dividends and redeem and purchase outstanding stock (as is necessary to meet its preferred stock sinking fund obligations) has been and may be further adversely affected, and possibly foreclosed for an indeterminate period of time, by write-offs and write-downs which have resulted and may hereafter result from regulatory actions or periodic reevaluation of the deregulated asset plan in Louisiana or other significant charges which may result from contingencies facing the Company. Potential changes in accounting standards could also affect the requirement for a write-off or write-down of the deregulated asset and the amount thereof.

Other Contingencies. The Company has been notified by the U. S. Environmental Protection Agency (EPA) that it has been designated as a potentially responsible party for the cleanup of sites on which the Company and others have or have been alleged to have disposed of material designated as hazardous waste. The Company is currently negotiating with the EPA and state authorities regarding the cleanup of some of these sites. Several class action and other suits have been filed in state and federal courts seeking relief from the Company and others for damages caused by the disposal of hazardous waste and for asbestos-related disease which allegedly occurred from exposure on Company premises. While the amounts at issue in the cleanup efforts and suits may be very substantial sums, management believes that its financial condition will not be materially affected by the outcome of the suits.

Detailed below are the cumulative amounts accrued and expended through December 31, 1992, for the cleanup of sites at which the Company has been designated as a potentially responsible party, in addition to the remaining estimated liability as of December 31, 1992.

	Amount Accrued through December 31, 1992	Amount Expended through December 31, 1992	Remaining Liability at December 31, 1992
		(In thousands)	
Environmental cleanup (six sites)	$25,568	$6,240	$19,328

The Federal Clean Air Act Amendments of 1990 impose new requirements to permit, measure, and control air pollution emissions from the Company's generating plants and will require additional capital expenditures for pollution control and measurement equipment and increased operating expenditures and permitting fees. Current estimates of expenditures to meet new requirements total approximately $22,000,000 over the next three to four years. Based upon the outcome of ongoing Company studies and depending upon pollution control standards to be set by the EPA and state environmental agencies, it may be determined that additional capital expenditures will be required above the present estimates.

The Company is also involved in litigation arising in the normal course of business. While the results of such litigation cannot be predicted with certainty, management believes that the final outcome will not have a material adverse effect on its financial condition.

4. Rates and Accounting

Rate Matters

Texas — Docket No. 7195. On May 16, 1988, the PUCT granted the Company a permanent increase in annual revenues of $59,900,000. The increase was based on including in rate base approximately $1.6 billion of the Company's system-wide River Bend plant investment and approximately $182,000,000 of related Texas retail jurisdiction deferred River Bend costs ruled prudent. Additionally, the PUCT affirmed its preliminary rulings made in February 1988, to disallow as imprudent $63,468,000 of the Company's system-wide River Bend plant costs and placed in abeyance approximately $1.4 billion of the Company's system-wide River Bend plant investment and approximately $157,000,000 of Texas retail jurisdiction deferred River Bend operating and carrying costs with no finding of prudency. The PUCT affirmed that the ultimate rate treatment of such amounts would be subject to future demonstration by the Company of the prudency of such costs. The Company, the Office of Public Utility Counsel, the Attorney General, and the intervening municipal groups appealed the PUCT order in Docket No. 7195. The Company also filed a separate rate case (Docket No. 8702) in which it asked that the abeyed River Bend plant cost be found prudent and included in rate base. Intervening parties filed suit in district court to prohibit the proceedings in Docket No. 8702. The district court's decision in that suit was ultimately appealed to the Texas Supreme Court, and the Texas Supreme Court ruled that the prudence of the costs purported to be held in abeyance by the PUCT in its May 16, 1988 order could not be relitigated in a separate rate proceeding such as Docket No. 8702. The Texas Supreme Court's decision stated that all issues relating to the merits of the original order of the PUCT, including the prudence of all River Bend related costs, remain to be addressed in the pending district court appeal.

On October 1, 1991, the district court handed down its decision in the Company's appeal of the May 1988 order from the PUCT. The decision stated that, while it was clear the PUCT made an error in assuming it could set aside $1.4 billion of the total costs of River Bend and consider them in a later proceeding, the PUCT, nevertheless, found that the

Company had not met its burden of proof related to the amounts placed in abeyance. The court also ruled that deferred costs associated with River Bend and Big Cajun 2 Unit 3 accrued after the units were placed in commercial operation, but prior to relevant rate orders, should not be included in rate base under a 1991 decision regarding El Paso Electric Company's (El Paso) similar deferred costs. The court further stated that the PUCT erred in reducing the Company's deferred costs by $1.50 for each $1.00 of revenue collected under the interim rate increases authorized in 1987 and 1988. The court remanded the case to the PUCT with instructions as to the proper handling of the deferred cost issues. The Company's motion for rehearing was denied, and on December 18, 1991, the Company filed an appeal of the October 1, 1991 district court order. The PUCT also appealed the October 1, 1991 district court order, which served to supersede the district court's judgment rendering it unenforceable under Texas law. On October 21, 1992, oral arguments were made before the Third District Court of Appeals on the Company's appeal. No assurance can be given as to the timing or outcome of the appeal.

As of December 31, 1992, on a Texas retail jurisdictional basis, the disallowed River Bend plant costs were approximately $18,000,000, and the River Bend plant costs held in abeyance totaled approximately $404,000,000, both net of accumulated depreciation and related taxes. As discussed below in "Accounting Developments—SFAS No. 109," on January 1, 1993, the Company is required to change its accounting for income taxes. Included in the Statement of Financial Accounting Standards (SFAS) No. 109 accounting change is an increase of deferred taxes associated with the disallowed and abeyed River Bend plant investment. Accordingly, on January 1, 1993, after recognition of the SFAS No. 109 effect, the disallowed River Bend plant cost will be approximately $14,000,000, and the River Bend plant costs held in abeyance will total approximately $315,000,000, both net of accumulated depreciation and related taxes.

The River Bend cost deferrals associated with the portion of the investment held in abeyance amounted to approximately $161,000,000, net of taxes, as of December 31, 1992. River Bend cost deferrals which were allowed in rate base in Texas were approximately $101,000,000, net of taxes, as of December 31, 1992. At December 31, 1992, the Company estimates it had collected approximately $111,000,000 of revenues as a result of the previously ordered rate treatment of these deferred costs and currently estimates that it collects approximately $2,300,000 monthly, or $28,000,000 annually, of revenues associated with such deferred costs from ratepayers in Texas. Deferred costs associated with Big Cajun 2 Unit 3 totaled approximately $4,312,000 (net of taxes) as of December 31, 1992, of which approximately $1,823,000 (net of taxes) were included in rate base by the PUCT. The remaining $2,489,000 (net of taxes) of deferred costs were included in the appeal of Docket No. 7195 before the court.

On August 26, 1992, the court of appeals in the El Paso case handed down its second opinion on rehearing modifying its previous opinion on deferred accounting for El Paso (which had been relied upon by the district court in the Gulf States case). The court's new opinion distinguishes between deferred carrying costs and deferred operating and maintenance costs, concluding that the PUCT may lawfully defer operating and maintenance costs and subsequently include them in rate base, but that the Public Utility Regulatory Act prohibits such rate base treatment for deferred carrying costs. The court stated, however, its opinion would not preclude the recovery of deferred carrying costs without rate base treatment. The court of appeals opinion has been appealed to the Texas Supreme Court.

If the August 26, 1992 court of appeals opinion is applied to the Company by the courts and the PUCT permits recovery through amortization of the deferred carrying costs, the possible write-off of deferred River Bend costs currently allowed in rates ($101,000,000) would be eliminated, and possible refunds would be reduced. At December 31, 1992, the Company estimates it had collected approximately $53,000,000 of revenues as a result of the current inclusion of deferred carrying costs in rate base. The Company collects approximately $1,000,000 per month as a result of such current rate base treatment.

The October 1, 1991 district court order also found that the PUCT erred in reducing the Company's deferred costs by $1.50 for each $1.00 of revenue collected under the interim rate increases authorized in 1987 and 1988. Elimination of the reduction of deferred costs from rate base could reduce the potential refund of amounts described in the preceding paragraph by amounts ranging from approximately $15,000,000 to $36,000,000.

No assurance can be given as to the timing or outcome of the appeals described above. Pending further developments in these cases, the Company has made no write-offs for the River Bend related costs discussed above. Management believes, based on advice from Clark, Thomas, Winters & Newton, a professional corporation, legal counsel of record in the appeal of Docket No. 7195, it is reasonably possible that the Company will prevail on appeal of the district court order and the case will be remanded to the PUCT, and that it is reasonably possible that the PUCT will be allowed to expressly rule on the prudence of the abeyed River Bend plant costs. Upon remand of Docket No. 7195, the PUCT can choose from several options. It can reexamine all aspects of the case, reexamine only a portion of the case, take additional testimony, or rely on the existing record, including the report of the three administrative law judges that heard the extensive testimony filed in the case; or, the PUCT can take some action that may lead the parties to settle the case without additional extensive litigation. At this time, management and legal counsel are unable to predict the amount, if any, of the abeyed and previously disallowed River Bend plant costs that may be ultimately disallowed by the PUCT. A write-off as of December 31, 1992, ranging from $0 to $422,000,000, could be required based on the PUCT's ultimate ruling.

Management believes that it is reasonably possible that it will recover, in rate base, or otherwise through means such as a deregulated asset plan, all, or substantially all, of the abeyed River Bend plant costs. Management believes that the abeyed River Bend plant costs were prudently incurred. However, management recognizes that it is reasonably possible that not all of the abeyed River Bend plant costs may ultimately be recovered.

In prior proceedings, the PUCT has held that the original cost of nuclear power plants will be included in rates to the extent those costs were prudently incurred. Based upon the PUCT's prior decisions, management believes that its River Bend construction costs were prudently incurred.

As part of its direct case in Docket No. 8702, the Company filed a cost reconciliation study prepared by Sandlin Associates, management consultants with expertise in the cost analysis of nuclear power plants, which supports the reasonableness of the River Bend costs held in abeyance by the PUCT. This reconciliation study determined that approximately 82 percent of the River Bend cost increase above the amount included by the PUCT in rate base was a result of changes in federal nuclear safety requirements and provided other support for the remainder of the abeyed amounts.

There have been four other rate proceedings in Texas involving nuclear power plants. Investment in the plants ultimately disallowed ranged from 0 percent to 15 percent for three of the companies. A disallowance of approximately 25 percent was ordered in the other case, however, approximately 66 percent of that disallowance was recently overturned by a district court, which results in a net 9 percent disallowance. Each case was unique, and the disallowances in each were made on a case-by-case basis for different reasons. Appeals of most, if not all, of these PUCT decisions are currently pending.

The following factors support management's position that a loss contingency requiring accrual has not occurred, and its belief that all, or substantially all, of the abeyed plant costs will ultimately be recovered:

1. The fact that the $1.4 billion of abeyed River Bend plant costs have never been ruled imprudent and disallowed by the PUCT.
2. Sandlin Associates' analysis which supports the prudence of substantially all of the abeyed construction costs.
3. Historical inclusion by the PUCT of prudent construction costs in rate base.
4. The analysis of the Company's internal legal staff, which has considerable experience in Texas rate case litigation.

Additionally, management believes, based on advice from Clark, Thomas, Winters & Newton, a professional corporation, legal counsel of record in the appeal of Docket No. 7195, that it is probable that the deferred operating and carrying costs discussed above will be recovered in rates as allowable costs. However, assuming the August 26, 1992 court of appeals opinion in the El Paso case regarding deferred costs, as discussed above, is upheld and applied to the Company, and the deferred River Bend costs currently held in abeyance, related to the $404,000,000 of abeyed plant costs, are not allowed to be recovered in rates as allowable costs, a write-off of up to $161,000,000 could be required. In addition, future revenues based upon the deferred costs previously allowed in rate base could also be lost; and no assurance can be given as to whether or not refunds (up to $53,000,000 as of December 31, 1992) of revenue received based upon such deferred costs previously recorded will be required.

Texas — Docket No. 8702. On March 21, 1989, the Company filed with the PUCT and Texas municipalities a request for additional rate increases. The Texas Supreme Court issued a ruling on September 12, 1990, that prevented the PUCT from conducting further hearings in Docket No. 8702 concerning the Texas jurisdictional portion of the $1.4 billion of River Bend costs placed in abeyance by the PUCT in Docket No. 7195. On April 22, 1991, the United States Supreme Court denied the Company's petition seeking review of the Texas Supreme Court ruling. Based on the Texas Supreme Court decision, the Company pursued a permanent increase on the non-River Bend portion of the case on which the PUCT could proceed.

On March 20, 1991, the PUCT, by a 2-1 vote, approved rates consistent with the terms of a Joint Recommendation offered by most of the parties to the Company's rate case. Under the rates set by the PUCT, the Company implemented a $30,000,000 increase in annual base revenue and retained approximately $16,800,000 in franchise tax refunds. The Company increased its annual fuel revenue by $17,500,000. The Company also agreed not to file a new base rate request for two years, subject to certain exceptions. The order was appealed by certain parties.

On December 13, 1991, the 53rd Judicial District Court of Travis County considered arguments on the appeals. In a judgment dated May 6, 1992, the District Court issued its order, which reversed and remanded to the PUCT the federal income tax issue and ordered a reconsideration of all of the findings of the PUCT's order. The District Court order generally followed the Court of Appeals decision in PUCT vs. GTE-SW as it related to the calculation of federal income taxes for regulatory purposes. In that case, the Court of Appeals applied an "actual taxes incurred" methodology for the allowance of federal income tax expense included in cost of service and allocated to the utility's ratepayers the tax benefits of certain operating expenses which had been disallowed in rates. The Court of Appeals did indicate that it was not ruling with respect to the proper treatment of certain "capital expense" items, which may be an important issue in any further consideration of the Company's case by the courts or the PUCT. The Company's case is currently in the process of being appealed, and the GTE-SW case was appealed to the Texas Supreme Court. On December 31, 1992, the Texas Supreme Court refused to accept the GTE-SW case. GTE-SW has filed a motion for rehearing with the Texas Supreme Court. At December 31, 1992, the Company estimates it had collected approximately $42,000,000 of revenues as a result of the disputed income tax calculation since the Company implemented an interim rate increase in December 1990, and currently estimates that it collects approximately $1,700,000 monthly of revenues associated with the disputed income tax calculation.

The PUCT recently applied a broader interpretation of the disputed income tax calculation to another Texas based utility. The PUCT ruling may be reviewed by the Internal Revenue Service, and may be found to be a violation of the Internal Revenue Code, which may result in the PUCT changing its application of its methodology in future cases. The Company estimates it has collected approximately $41,000,000 of revenue subject to the Company's interpretation of the PUCT's broader application since the interim rate increase in December 1990, in addition to the $42,000,000 discussed above. The application of the PUCT's methdology is subject to several uncertainties not addressed in the GTE-SW decision, and it is unclear how this methodology might be applied if Docket No. 8702 is remanded to the PUCT. Accordingly, the ultimate result and impact on the Company of the GTE-SW decision and the PUCT's recent ruling cannot be determined at this time, but the outcome could be a reduction of rates and requirement of a refund of prior collections. There can be no assurance as to the timing or ultimate outcome of such appeals.

Texas — Joint Venture. In 1986, the Company filed with the PUCT a request for recovery of the costs of purchasing power from the Nelson Industrial Steam Company (NISCO), the joint venture with three industrial companies and the Company, which now owns Nelson Units 1 and 2. The PUCT ordered that purchased power costs in excess of the Company's avoided costs be disallowed and that 83 percent of the proceeds from the sale of the units by the Company to the venture be allocated to ratepayers. The PUCT disallowance resulted in approximately $12,000,000 to $15,000,000 of unrecovered purchased power costs on an annual basis. On April 3, 1991, the Supreme Court of the State of Texas, in the appeal of such order, ordered the PUCT to allow the Company to recover purchase power payments in excess of its avoided cost in future proceedings, if the Company established to the PUCT's satisfaction that the payments are reasonable and necessary expenses. If the Company is able to satisfy the PUCT that the costs in excess of avoided costs are justified, the Court stated that the PUCT should then determine what portion of the costs are reasonable and necessary for the ratepayers to bear, given the distribution of benefits from the project to the ratepayers and to the shareholders. The Court further found that the PUCT's decision to allocate 83 percent of the sale proceeds to the ratepayers was not reasonably supported by substantial evidence in the record and remanded the issue to the PUCT for further consideration. Whether the Company will be allowed to recover purchased power costs in excess of the Company's avoided cost will depend upon the outcome of the fuel reconciliation discussed below. As of December 31, 1992, the Company had recorded, with no effect on net income, $66,619,000 of unrecovered purchased power costs and deferred revenue (including interest), based upon the court order, pending the determination of the reasonableness and necessity of the costs in a new proceeding.

The issue regarding the treatment of the sale proceeds discussed above will be addressed in a future rate proceeding.

Texas — Fuel Reconciliation. On January 21, 1992, the Company applied with the PUCT for a new fixed fuel factor and requested a final reconciliation of fuel and purchased power costs through September 30, 1991. The Company proposed to recover net underrecoveries and interest (including the underrecoveries related to NISCO, discussed above) over a twelve month period, which at December 31, 1992 was $21,563,000. Hearings began on October 8, 1992, and continued through November 6, 1992. No assurance can be given as to the timing or outcome of the proceedings.

Louisiana. Previous rate orders of the LPSC have been appealed, and pending resolution of various appellate proceedings, the Company has made no write-off for the disallowance of $30,563,000 of deferred revenue requirement that the Company recorded for the period December 16, 1987 through February 18, 1988.

Louisiana Supreme Court Ruling. On April 5, 1991, the Louisiana Supreme Court reversed and set aside a February 18, 1988 district court order which increased the Company's allowed rate of return on equity from 12 percent to 14 percent during the first year of the phase-in plan. The Supreme Court decision stated that the total amount in dispute with regard to the rate of return issue was approximately $20,000,000 in revenue collected by the Company from February 18, 1988 to March 1, 1989.

In the second quarter of 1991, the Company recorded a reserve of $20,000,000 for a possible refund based upon the rate of return issue. On January 28, 1992, the LPSC ordered a refund of $34,945,000 (representing return on equity-related overcollections of $24,143,000 and $10,802,000 of interest) instead of the $20,000,000 previously indicated in the Louisiana Supreme Court order and reserved for in the second quarter of 1991. Accordingly, the Company recorded an additional refund reserve, including interest, of $14,945,000 in the fourth quarter of 1991. Approximately one-half of the $24,143,000 refund principal was refunded in July 1992, and the remainder will be refunded in July 1993. Interest was recorded and continues to accrue as credits to the deferred River Bend revenue requirement associated with the phase-in plan.

Louisiana Deregulated Asset Plan. On January 28, 1992, the LPSC ordered that the previously ordered deregulated asset plan be retained, subject to certain conditions. Such conditions include changing the sharing mechanism for incremental revenue derived from off-system sales from the previously ordered 60 percent for ratepayers/40 percent for shareholders to a split of 50 percent for ratepayers/50 percent for shareholders. Accordingly, the Company applied the provisions of SFAS No. 101, Regulated Enterprises — Accounting for the Discontinuation of Application of FASB Statement No. 71, which resulted in no write-down of the deregulated portion of River Bend; however, the application of SFAS No. 101 did require an increase in deferred taxes and other adjustments of $20,166,000 ($.18 per share of common stock), which was recorded as an extraordinary item in 1991. Due to the state net operating loss carryforward position the Company is in, a previously unrecorded offsetting state tax benefit of $13,100,000 from operations-related tax loss carryforwards ($.12 per share of common stock) is included in "Income Taxes — State."

Louisiana Management Audit. On October 22, 1991, a majority of LPSC commissioners voted by a 3-2 vote not to turn the management audit into a rate proceeding. In November 1991, the Company filed its implementation plan with the LPSC. The Company has engaged in negotiations with the LPSC's counsel and consultants to refine such plan. After consideration of such plan, the LPSC will determine whether any further action will be taken based on the audit.

Accounting Developments

Accounting for Power Plant Materials and Supplies. During the first quarter of 1992, accounting procedures were changed to include in inventory, power plant materials and supplies previously expensed or capitalized as plant in service. The Company believes this change provides a better matching of costs with related revenues. The change resulted from recommendations during recent audits by the FERC and LPSC, in addition to a general change in industry practice. The pro forma effect of retroactive application on any period prior to 1992 is not determinable as, prior to this change, the Company did not perform the physical inventory counts necessary to determine inventory balances in prior periods. The effect of the change was to increase materials and supplies by $76,621,000, of which $41,124,000 associated with the Company's Texas and Louisiana retail jurisdictions was deferred and to decrease amounts previously capitalized, primarily plant in service, by $28,987,000. Amounts deferred for the Louisiana retail jurisdiction are currently being amortized to income over approximately seven years, through February 1998, while amounts deferred for the Texas retail jurisdiction will be amortized to income in future years. The cumulative effect of this accounting change as of January 1, 1992, which relates to the operations on which the Company has discontinued regulatory accounting principles, amounted to $6,510,000 before the related income tax effect of $2,543,000 ($.04 per average share of common stock).

SFAS No. 101. In December 1988, the Financial Accounting Standards Board (FASB) issued SFAS No. 101, which specifies how an enterprise that ceases to meet the criteria for application of SFAS No. 71, Accounting for the Effects of Certain Types of Regulation, to all or part of its operations should report that event in its general-purpose external financial statements. During 1989, the Company discontinued regulatory accounting principles for the wholesale jurisdiction and steam department. As discussed in "Rate Matters — Louisiana Deregulated Asset Plan" above, the Company discontinued regulatory accounting principles to the Louisiana deregulated portion of River Bend in 1991.

Loss on the Extinguishment of Debt. During 1992, the Company extinguished $1,030,435,000 of long-term debt, through refinancings. A loss of $81,763,000 was recorded associated with the extinguished debt. In accordance with generally accepted accounting principles for regulated enterprises, the Company deferred $67,222,000 of the loss, representing the portion of the Company's operations allocable to the Texas and Louisiana retail jurisdictions, and began to amortize that amount over the life of the new debt sold to retire the existing debt. The remaining net of tax loss of $9,597,000 ($.09 per share of common stock) was charged to income in 1992 as an extraordinary item.

Louisiana Rate Order. In accordance with the rate order in Louisiana effective March 1, 1991, the LPSC required the Company to modify its treatment of certain flow through benefits related to AFUDC recorded on capital expenditures prior to 1986. Accordingly, the Company increased net utility and other plant and accumulated deferred income taxes by $62,967,000. The rate order requires the Company to amortize the increase in plant in service over approximately 35 years, the estimated remaining life of River Bend, and to amortize the increase in deferred taxes over approximately seven years. This will result in the Company recording less Operating Expenses and Taxes for the amortization period of those deferred income taxes, thereby increasing net income for that period.

SFAS No. 109. In February 1992, the FASB issued SFAS No. 109, Accounting for Income Taxes, which significantly changes accounting for income taxes and supersedes almost all existing authoritative accounting literature on accounting for income taxes. SFAS No. 109 revises the computation of deferred income taxes so that the amount of deferred income taxes on the balance sheet is adjusted whenever tax rates or other changes of the income tax law are enacted. SFAS No. 109 also prohibits net of tax accounting and reporting and requires recognition of deferred tax liabilities for tax benefits previously flowed through to ratepayers. Adoption of SFAS No. 109 is required in 1993. The adoption of SFAS No. 109 may be recorded by restating prior years' financial statements or by recording the cumulative effect of the change in the year of adoption. The Company presently plans to record the adoption of SFAS No. 109 by restating 1990, 1991, and 1992 financial statements. Detailed below are the estimated effects on the Company's results of operations and financial position resulting from such restatement:

	1990 As Reported	SFAS No. 109 Effect	1990 As Restated
	(in thousands)		
Income (Loss) Before Extraordinary Items and the Cumulative Effect of Accounting Change	$ (44,282)	$ 7,883	$ (36,399)
Cumulative Effect of the Adoption of SFAS No. 109 on Years Prior to 1990	—	(96,494)	(96,494)
Net Loss	(44,282)	(88,611)	(132,893)
Loss Applicable to Common Stock	(107,024)	(88,611)	(195,635)
Earnings (Loss) Per Average Share of Common Stock Outstanding Before Extraordinary Items and the Cumulative Effect of Accounting Change	(0.99)	0.07	(0.92)
Loss Per Average Share of Common Stock Outstanding	(0.99)	(0.82)	(1.81)
Total Assets	6,863,269	589,510	7,452,779
Total Capitalization and Liabilities (Excluding Retained Earnings)	6,152,632	678,121	6,830,753
Retained Earnings	710,637	(88,611)	622,026

	1991 As Reported	SFAS No. 109 Effect	1991 As Restated
	(in thousands)		
Income Before Extraordinary Items and the Cumulative Effect of Accounting Change	$ 122,449	$(10,058)	$ 112,391
Net Income	102,283	9,747	112,030
Income Applicable to Common Stock	39,213	9,747	48,960
Earnings Per Average Share of Common Stock Outstanding Before Extraordinary Items and the Cumulative Effect of Accounting Change	0.52	(0.09)	0.43
Earnings Per Average Share of Common Stock Outstanding	0.34	0.09	0.43
Total Assets	6,911,492	557,317	7,468,809
Total Capitalization and Liabilities (Excluding Retained Earnings)	6,164,735	636,181	6,800,916
Retained Earnings	746,757	(78,864)	667,893

	1992 As Reported	SFAS No. 109 Effect	1992 As Restated
	(in thousands)		
Income Before Extraordinary Items and the Cumulative Effect of Accounting Change	$ 133,787	$ 5,691	$ 139,478
Net Income	128,157	5,691	133,848
Income Applicable to Common Stock	78,455	5,691	84,146
Earnings Per Average Share of Common Stock Outstanding Before Extraordinary Items and the Cumulative Effect of Accounting Change	0.74	0.05	0.79
Earnings Per Average Share of Common Stock Outstanding	0.69	0.05	0.74
Total Assets	6,858,494	537,085	7,395,579
Total Capitalization and Liabilities (Excluding Retained Earnings)	6,153,859	610,258	6,764,117
Retained Earnings	704,635	(73,173)	631,462

If the Company elected to not restate prior years' financial statements, the adoption of SFAS No. 109 would result in a charge to net income in the first quarter of 1993 of $73,173,000.

Management beli.ves it is probable that the future increase in taxes payable, resulting from the reversal of tax benefits previously flowed through to customers and other temporary differences, will be recovered from customers through future rates and, therefore, the Company will record a regulatory asset pursuant to SFAS No. 71 upon the adoption of SFAS No. 109, as detailed above. Rate actions of a regulator can reduce or eliminate the value of an asset. If the LPSC or PUCT excludes all or part of the future taxes recorded as a regulatory asset from allowable costs and it is not probable that the regulatory asset will be included as an allowable cost in a future period, the carrying amount of the regulatory asset would be reduced if such assets have been impaired.

River Bend Cost Deferrals. Pursuant to accounting orders received in 1986 from the LPSC and the PUCT, the Company deferred recognition, for financial reporting purposes, of the retail portion of the operating costs associated with River Bend and costs of purchasing capacity from CEPCO's portion of the unit incurred subsequent to the unit's commercial in-service date and accrued carrying charges upon the retail portion of both the cash portion of the deferrals and the investment in the unit not included in the Company's rate base. The deferral of costs and accrual of carrying charges associated with River Bend was terminated in the Louisiana retail jurisdiction on December 15, 1987, upon receipt of the permanent rate decision and terminated in the Texas retail jurisdiction on July 23, 1988, the effective date of rates authorized by the PUCT rate order of May 16, 1988. See "Rate Matters — Texas — Docket No. 7195" for subsequent rate action regarding Texas accounting order deferrals.

Detailed below are the components of Deferred River Bend costs included in DEFERRED CHARGES AND OTHER ASSETS:

	Balance at December 31, 1991	Changes for the Year Ended December 31, 1992		Balance at December 31, 1992
		Refund	Amortization	
		(in thousands)		
DEFERRED REVENUE REQUIREMENTS — PHASE-IN PLAN				
Louisiana retail jurisdiction	$305,157	$(2,290)	$(27,167)	$275,700
ACCOUNTING ORDER DEFERRALS				
Texas retail jurisdiction				
Deferred River Bend costs	368,953	—	—	368,953
Amortization of deferred River Bend costs	(20,462)	—	(9,078)	(29,540)
Louisiana retail jurisdiction				
Deferred River Bend costs	400,375	—	—	400,375
Amortization of deferred River Bend costs	(162,455)	—	(38,770)	(201,225)
	586,411	—	(47,848)	538,563
DEFERRED RIVER BEND COSTS	$891,568	$(2,290)	$(75,015)	$814,263

The deferred income taxes related to the amounts detailed above at December 31, 1992 and 1991 of $211,562,000 and $232,038,000, respectively, are included in "DEFERRED CREDITS AND OTHER LIABILITIES — Accumulated deferred income taxes" on the Consolidated Balance Sheet.

Detailed below are the components of Deferred River Bend financing costs included in DEFERRED CREDITS AND OTHER LIABILITIES:

	Balance at December 31, 1991	Changes for the Year Ended December 31, 1992	Balance at December 31, 1992
		Amortization	
		(in thousands)	
DEFERRED RIVER BEND FINANCING COSTS			
Texas retail jurisdiction	$ 93,156	$(14,202)	$ 78,954
Louisiana retail jurisdiction	62,326	(10,157)	52,169
DEFERRED RIVER BEND FINANCING COSTS	$155,482	$(24,359)	$131,123

Recovery of Costs — Amortization of Accumulated Deferred River Bend Costs. The Company was ordered by the LPSC, as part of the December 15, 1987 rate order, to amortize the deferred costs and accrued carrying charges related to the accounting order over a 10-year period. The Company is amortizing approximately $182,000,000 of deferred costs and accrued carrying charges associated with the portion of River Bend ruled prudent by the PUCT over a 20-year period in accordance with the March 22, 1991 Texas rate order. Approximately $187,000,000 of Texas retail jurisdiction deferred River Bend costs are not being amortized pending the ultimate outcome of the appeals of Docket No. 7195.

5. Federal Income Taxes

The provisions for federal income taxes (benefits) were different from the amounts computed by applying the statutory federal income tax rate to net income (loss) before federal income taxes. The reasons for these differences are as follows:

	1992	1991	1990
	(in thousands except percents)		
Net income (loss) before federal income taxes	$186,894	$160,685	$(60,781)
Statutory federal tax rate	34%	34%	34%
Federal income taxes (benefits) at statutory tax rate	63,544	54,633	(20,666)
Additions (reductions) in federal income taxes resulting from:			
Exclusion of River Bend carrying charges from taxable income	8,589	8,663	8,139
Items capitalized for book purposes but expensed for tax purposes	(10,127)	(10,319)	(9,235)
Non-deferred depreciation differences	966	3,412	11,058
Adjustment for prior years taxes and other regulatory adjustments	(817)	1,250	(157)
Non-deferred differences of nonutility subsidiaries	414	573	(900)
Deferral of nuclear fuel savings	(1,894)	(1,920)	(1,573)
Amortization of investment tax credit	(4,356)	(4,308)	(4,286)
Effect of SFAS No. 101	(399)	6,500	(443)
Other items	2,817	(82)	1,564
Total federal income taxes (benefits)	$ 58,737	$ 58,402	$(16,499)
Effective federal income tax rate	31.4%	36.3%	27.1%

The components of federal income taxes are as follows:

	1992	1991	1990
	(in thousands)		
Charged to operating expenses:			
Current federal income tax provision (benefits)	$ 1,450	$ 3,558	$ (5,084)
Deferred federal income taxes — net			
Loss on debt extinguishment, net of amortization	22,314	—	—
Tax depreciation	33,376	31,576	49,773
Capitalized construction costs	(646)	(666)	(266)
Nuclear unit cancellation costs, net of amortization	(2,352)	(2,352)	(2,383)
Fuel and purchased power costs (accrued)	(577)	(4,012)	(673)
Expenses deferred for tax purposes	2,810	(4,525)	(1,240)
Tax net operating loss carryforward	9,702	50,473	17,981
River Bend operating expenses deferred for financial reporting, expensed for tax purposes	(17,846)	(12,780)	7,111
Unbilled revenues	2,491	701	(6,632)
Income deferred for book purposes	(102)	(12,152)	(696)
Provision for rate refund — Louisiana	4,416	(8,209)	—
Alternative minimum tax credit	(8,197)	(5,595)	(3,632)
Other	(806)	(1,569)	(3,333)
Total deferred federal income taxes — net	44,583	39,890	56,010
Investment tax credits — net	(2,200)	(4,308)	(4,286)
Total federal income taxes charged to operating expenses	43,833	39,140	46,640
Southern Company settlement	—	—	(69,705)
Charged to other income — net	17,633	12,760	6,566
Charged to extraordinary items	(4,943)	6,502	—
Charged to cumulative effect of accounting change	2,214	—	—
Total federal income taxes (benefits)	$58,737	$58,402	$(16,499)

Timing differences exist for which federal and state deferred taxes have not been provided and, therefore, have not been recovered through rates. The cumulative amount of timing differences for which no federal deferred taxes have been provided was approximately $74,000,000 at December 31, 1992. The tax effects of the Company's federal tax loss carryforwards have been recorded as reductions of deferred taxes. Investment tax credit carryforwards have not been recorded for book purposes. At December 31, 1992, for tax purposes, the Company had federal tax loss carryforwards of approximately $785,000,000 and investment tax credit carryforwards of approximately $181,000,000. These will be used to reduce income tax payments in future years and, if not used, will expire through the year 2004.

6. Retirement Plan and Other Postemployment Benefits

Retirement Plan. The Company has a noncontributory pension plan which covers all employees meeting certain age and service requirements. Benefits are based on years of service and the highest five consecutive years of employees' compensation during the last 10 years of service. All of the Company's eligible employees are entitled to retirement benefits upon completion of 10 years of service and after reaching age 50. The Company's policy is to fund the actuarially computed pension contribution annually. Past and prior service costs, which are due primarily to retirement plan amendments, are being funded by the Company over periods of up to 40 years.

The Company's pension provision for the years ended December 31, 1992, 1991, and 1990 was $3,512,000, $5,110,000, and $3,025,000, respectively. Of such amounts, $3,293,000, $4,552,000, and $2,693,000, respectively, were charged to income with the balance of such costs for each period charged to construction and other accounts.

The components of the pension provision for 1992, 1991, and 1990, are summarized as follows:

	1992	1991	1990
	(in thousands)		
Service cost	$12,396	$10,306	$ 9,660
Interest cost on projected benefit obligation	16,307	15,355	14,224
Actual return on plan assets	(28,117)	(56,898)	6,875
Unrecognized net gain (loss)	3,928	37,349	(25,520)
Amortization of net gain	—	—	(1,212)
Amortization of prior service cost	1,385	1,385	1,385
Amortization of net transition asset	(2,387)	(2,387)	(2,387)
Net pension cost	$ 3,512	$ 5,110	$ 3,025

The obligations for plan benefits and the amount recognized in the Company's Consolidated Balance Sheet at December 31, 1992, 1991, and 1990, are reconciled as follows:

	1992	1991	1990
	(in thousands)		
Actuarial Present Value of Benefit Obligations:			
Accumulated benefit obligation, including vested benefits of $206,860, $186,161, and $170,721, respectively	$ 219,086	$ 192,692	$ 174,789
Projected benefit obligation	$(289,988)	$(248,817)	$(228,328)
Plan assets, at fair market value	306,660	290,211	235,671
Plan assets in excess of projected benefit obligation	16,672	41,394	7,343
Unrecognized net gain	(27,906)	(48,930)	(13,417)
Unrecognized net assets, being amortized over 15 years	(19,099)	(21,487)	(23,874)
Unrecognized prior service cost	24,671	26,873	25,717
Accrued pension liability	$ (5,662)	$ (2,150)	$ (4,231)

The accumulated benefit obligation is the present value of future pension benefit payments and is based on the plan's benefit formulas without considering expected future salary increases. Assumptions used to determine net pension cost are as follows:

	1992	1991	1990
Discount rate	6.50%	7.25%	7.25%
Expected long-term rate of return on assets	8.50	8.50	7.50
Average future salary level increase	5.75	6.10	6.10

At December 31, 1992, 63 percent of plan assets were invested in equity securities, 31 percent in bonds, and 6 percent in cash or cash equivalents.

In addition to the net pension cost detailed above, the Company recorded $662,000 of expense related to the 1986 early retirement plan and 1990 workforce restructuring for the year ended December 31, 1992, in accordance with regulatory treatment of this expense.

Other Postemployment Benefits. In addition to the pension plan, the Company provides retired employees and their families with life and health care insurance benefits. All of the Company's employees may become eligible for benefits upon retirement. The Company currently records the cost of such benefits as claims are actually paid. The cost of such benefits was $5,340,000, $5,514,000, and $4,722,000 for the years 1992, 1991, and 1990, respectively.

SFAS No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions, requires the Company, beginning in 1993, to change the method of accounting for such benefits to the accrual method. The Company estimates that it will have an unrecognized accumulated postretirement benefit obligation of $128,000,000 as of January 1, 1993. The Company has elected to amortize the unrecognized transition obligation over twenty years. Total charges for postretirement benefits under the provisions of SFAS No. 106, including the amortization of the transition obligation, are currently estimated to increase by approximately $15,800,000 in 1993. Amounts ultimately recorded in accordance with SFAS No. 106 will be influenced by, among other things, the actuarial assumptions used by the Company and the regulatory treatment of the costs received by the Company.

7. Jointly-Owned Facilities

As of December 31, 1992, the Company owned undivided interests in three jointly-owned electric generating facilities as detailed below (dollars in thousands):

	River Bend Unit 1	Roy S. Nelson Unit 6	Big Cajun 2 Unit 3
Company Share of Investments:			
Plant in service	$3,070,947	$389,551	$219,811
Accumulated depreciation	486,504	123,866	61,868
Total plant capability	931 MW*	550 MW	540 MW
Fuel source	Nuclear	Coal	Coal
Ownership share	70%	70%	42%

The Company's share of operations and maintenance expense related to the jointly-owned units is included in operating expenses. See Note 3 for information regarding unpaid amounts by CEPCO for their share of River Bend costs during 1992. See Note 12 for information relating to a buyback agreement between the Company and a participant in Nelson Unit 6.

* The total plant capability has been decreased by 5 MW until replacement of turbine rotors are made, which are currently scheduled for March 1994.

8. Leases

The Company has existing agreements for the leasing of certain vehicles, coal rail cars and other equipment, buildings, nuclear fuel, and the storage of natural gas. Lease charges were $54,275,000, $73,554,000, and $65,984,000, for the years ended December 31, 1992, 1991, and 1990, respectively. Of such amounts, $53,356,000, $72,976,000, and $65,114,000, respectively, were charged to income.

Future minimum lease payments under noncancellable capital and operating leases for each of the next five years and in the aggregate at December 31, 1992, are estimated to be:

	Minimum Lease Payments (in thousands)
1993	$ 82,730
1994	68,465
1995	64,564
1996	33,577
1997	21,436
Remaining years	196,304
	$467,076

The Company is leasing the Lewis Creek generating station from its wholly-owned consolidated subsidiary, GSG&T.

9. Capital Stock and Retained Earnings

The Company offers its common and preferred shareholders the opportunity to reinvest their dividends and to make additional cash payments to acquire shares of the Company's common stock through its Dividend Reinvestment and Stock Purchase Plan (DRIP).

Common Stock and Retained Earnings. The Company offers all employees meeting designated service requirements the option to participate in benefit plans which provide an opportunity to obtain common shares of the Company. At December 31, 1992, the Company had reserved 5,562,503 unissued shares of common stock to be issued in connection with its DRIP and employee benefit plans. Beginning in June 1987, the Company has acquired the DRIP and employee benefit plan shares of common stock in the open market rather than offering unissued shares, which would have a dilutive effect on earnings per share and book value.

Certain limitations on the payment of cash dividends on common stock are contained in the Articles, Mortgage Indenture, loan agreements, the Reorganization Agreement with Entergy, and applicable state and federal law. Under existing limitations, as discussed in Notes 3 and 11, the Company may not pay dividends on such stock. If such restrictions did not exist, the most restrictive limitation at December 31, 1992, as to the amount of such dividends which might be paid, was contained in the Articles. Based on such limitation, the retained earnings available for payment of dividends as of December 31, 1992, amounted to $696,000,000. Preferred dividend requirements, as well as preferred stock sinking fund requirements, have priority over the payment of cash dividends on common stock.

Preferred Stock. At December 31, 1992, the Company had authorized 10,000,000 shares of preferred stock without par value (none issued) and authorized 6,000,000 shares of preferred stock $100 par value (4,058,311 issued). Limitations based on the ratio of after-tax earnings to fixed charges and preferred dividends are imposed by the Articles upon the issuance of additional preferred stock. Based upon the results of operations for the year ended December 31, 1992, and existing circumstances, the Company believes it is unable to issue any additional preferred stock.

During 1992, the Company retired $55,926,000 of preferred stock through sinking fund requirements, including $28,393,000 of preferred stock sinking fund arrearages as of December 31, 1991. The Articles provide that, at the Company's option, all or part of its preferred stock may be redeemed at stated prices.

The series of preferred stock subject to mandatory redemption are entitled to sinking funds which provide for the annual redemption of shares (varying in amount from 3 percent to 5 percent of the number of shares originally issued) at $100 per share. At December 31, 1992, minimum sinking fund requirements amount to $14,816,700 for each of the years from 1993 through 1997.

Preference Stock. On April 24, 1992, the Board of Directors authorized a portion of the proceeds from a sale of first mortgage bonds, together with cash from other sources, to be used to pay cumulative preference stock dividend arrearages and redeem the outstanding preference stock, including redemption premiums. On June 4, 1992, the Company paid $90,340,000 of preference stock dividend arrearages and accrued dividends, and redeemed $100,000,000 of outstanding preference stock, plus redemption premiums of $18,300,000.

Payment of dividends on preference stock is subordinate to payment of dividends on preferred stock and preferred stock sinking fund obligations. There are no limitations in the Articles on the issuance of authorized preference stock.

10. Long-Term Debt

The Company's Mortgage Indenture contains sinking fund provisions which require, generally, that the Company make annual cash deposits equal to 1.2 percent of the greatest aggregate principal amount of first mortgage bonds outstanding or, in lieu thereof, to apply property additions or reacquired first mortgage bonds for that purpose. The Company has satisfied the mortgage requirements in past years and expects to meet current and future requirements by certifying "available net additions" to the trustee.

Certain series of the Company's first mortgage bonds and pollution control and industrial development bonds require cash sinking funds. Sinking fund requirements, along with long-term debt maturities, for each of the next five years are detailed below:

	Sinking Fund Requirements Satisfied by		Long-Term Debt Maturities	
	Cash	Property Additions	First Mortgage Bonds and Debentures	Notes Payable—Southern Company
			(in thousands)	
1993	$ 425	$21,240	$ —	(a)
1994	425	21,240	—	—
1995	50,425	21,240	—	—
1996	50,425	20,100	95,000	—
1997	50,865	18,780	110,000	—

(a) As discussed in Note 3, the Company paid Southern $111,329,000 to retire promissory notes and paid $6,471,000 under a common stock differential agreement on January 4, 1993. The unpaid $48,671,000 of promissory notes and $2,829,000 of the common stock price differential are payable on the earlier of the January 1st as of which the Company has "adequate cash" or January 1, 1999, or earlier at the Company's discretion upon five days notice.

The Company's Mortgage Indenture contains an interest coverage covenant which limits the amount of first mortgage bonds which the Company may issue, based upon interest coverage for a period of twelve consecutive months within the fifteen months preceding a new debt issuance. Based upon the results of operations for the year ended December 31, 1992, during such fifteen month period, the Company believes it could issue $812,000,000 of first mortgage bonds in addition to the amount presently outstanding (assuming an interest rate of 9 percent for additional first mortgage bonds).

1992 Debt Refinancings. During 1992, the Company refinanced $1,030,435,000 of high cost long-term debt as detailed below:

	New Debt Issued	Retired Debt
	(in thousands)	
January 1992 First Mortgage Bond Refinancing	$ 300,000	$ 282,878
April 1992 First Mortgage Bond Refinancing	600,000	382,272
August 1992 Pollution Control Bond Refinancing	48,285	48,285
November 1992 First Mortgage Bond Refinancing	300,000	317,000
	$1,248,285	$1,030,435

The debt issued during 1992 has an average interest rate of 8.1%, while the debt retired had an average interest rate of 12.5%.

At various times during 1992, the Company remarketed a total of $80,600,000 of pollution control bonds at fixed interest rates. The bonds, which had previously carried variable interest rates, were secured by letters of credit which were scheduled to expire in 1992.

American Municipal Bond Assurance Corporation (AMBAC). In 1982 and 1983, the Company issued $48,285,000 and $17,450,000 of pollution control bonds, respectively, whose principal and interest were guaranteed by AMBAC.

In August 1992 and January 1993, the Company refinanced the $48,285,000 and $17,450,000 of pollution control bonds, respectively. The principal and interest on the new pollution control bonds are not guaranteed by AMBAC. Notes that had previously been issued to AMBAC were canceled, and amounts previously placed in reserves in accordance with agreements between AMBAC and the Company were returned to the Company.

Letters of Credit. The Company has various outstanding series of pollution control revenue bonds (bonds) which are collateralized by irrevocable letters of credit. The letters of credit are scheduled to expire before the scheduled maturity of the bonds. Detailed below is a maturity schedule of the bonds and related letters of credit.

	Principal Amount	Letter of Credit Expiration
	(in thousands)	
Variable rate due April 1, 2016	$20,000	April 27, 1993
10⅝% due May 1, 2014	50,000	May 15, 1994
Variable rate due December 1, 2015	28,400	December 28, 1995

If the letter of credit that expires in 1993 is not renewed or replaced, the Company plans to remarket and cause the pollution control bonds to remain outstanding. If the Company is unsuccessful in these actions, the pollution control bonds will be redeemed.

11. Short-Term Lines of Credit

As of December 31, 1992, the Company had agreements with banks and banking institutions which provided for short-term lines of credit totaling $113,400,000 of which $100,000,000 is collateralized as described below. Interest rates associated with these lines are based on the prime rate. Commitment fees on the collateralized line of credit cost ⅜ of 1 percent of the amount of available credit. Commitment fees on uncollateralized lines of credit cost ½ of 1 percent of the amount of available credit. In lieu of commitment fees on the uncollateralized lines, certain banks require a nonrestricted cash balance be maintained equal to 10 percent of the commitment.

Included in the total short-term lines of credit is a $100,000,000 bank credit agreement which is due to expire on March 15, 1993. The short-term bank credit agreement contains negative covenants which, among other restrictions, restrict payment of dividends on and acquisition of common stock, sale of assets and mergers (with certain exceptions), and requires satisfaction of a minimum net worth test as a condition to new borrowings. The proposed business combination with Entergy is a permitted transaction under this short-term bank credit agreement. One condition to having the ability to make new borrowings under the agreement is the absence of material adverse changes since December 31, 1991.

The Company had no short-term debt outstanding with banks and banking institutions during the three-year period ended December 31, 1992.

12. Purchase Power Agreements

As of December 31, 1992, the Company has an agreement with Sam Rayburn Municipal Power Agency to buy back declining amounts of its share of the capacity of Nelson Unit 6 through the end of May 1996. The Company had a five-year agreement with CEPCO, which expired June 15, 1991, to buy back declining amounts of their share of the capacity of River Bend. The variable costs associated with such buybacks are composed of fuel costs and operations and maintenance expenses, while the fixed costs are based upon gross plant investment and other factors.

	1992	1991	1990
	(in thousands)		
Nelson Unit 6			
Variable costs	$4,956	$7,679	$7,469
Fixed costs	6,322	8,184	9,568

Based upon current information, the Company estimates that the annual fixed costs incurred in connection with the Nelson Unit 6 buybacks will range in declining amounts from $4,700,000 in 1993, to $1,200,000 in 1996.

	1991	1990
	(in thousands)	
River Bend		
Variable costs	$ 6,499	$14,940
Fixed costs	23,280	50,312

Nelson Industrial Steam Company (NISCO). In 1988, the Company entered into a joint venture with a primary term of 20 years with Conoco, Inc., Citgo Petroleum Corporation, and Vista Chemical Company (the industrial participants) whereby the Company's Nelson Units 1 and 2 (106 MW each as of December 31, 1992) were sold to a partnership (NISCO) consisting of the industrial participants and the Company.

The industrial participants are supplying the fuel for the units, while the Company operates the units at the discretion of the industrial participants and purchases the electricity produced by the units. The Company is continuing to sell electricity to the industrial participants.

For the years ended December 31, 1992, 1991, and 1990, the purchases of electricity from the joint venture totaled $37,792,000, $61,316,000, and $62,028,000, respectively.

13. Financial Instruments

Temporary Cash Investments. At December 31, 1992 and 1991, the Company had $197,021,000 and $291,845,000 of temporary cash investments invested in repurchase agreements or high grade short-term corporate investments, with six and nine banks and investment banks, respectively. The repurchase agreements are collateralized by U. S. Government securities or high grade short-term corporate investments. The Company has not experienced any losses on its temporary cash investments.

Accounts Receivable. The Company's service area of Southeast Texas and Southwest Louisiana is heavily dependent on the petrochemical and related industries. The Company maintains reserves for doubtful accounts, based on past experience.

Disclosures About Fair Value of Financial Instruments. The following methods and assumptions were used to estimate the fair value of each of the Company's financial instruments.

Cash and Temporary Cash Investments — The carrying amount approximates fair value due to the short maturity of those instruments.

Investment Securities — Decommissioning and Self Insurance Fund's — The fair value of the investments included in the decommissioning and self insurance fund's are based on the quoted market prices.

Long-Term Debt and Preferred Stock Subject to Mandatory Redemption — The fair value of the Company's long-term debt and preferred stock subject to mandatory redemption is estimated based on the quoted market prices for the same or similar issues or on the current rates offered to the Company for debt of the same remaining maturities.

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

	1992	
	Carrying Amount	Fair Value
	(in thousands)	
Cash and temporary cash investments	$ 197,741	$ 197,741
Decommissioning fund	14,102	14,546
Self insurance fund	20,950	21,531
Long-term debt	2,541,028	2,622,953
Preferred stock subject to mandatory redemption	269,387	279,530

14. Quarterly Financial Information (Unaudited) (in thousands except per share amounts)

1992	Operating Revenue	Operating Income	Income Before Extraordinary Items and the Cumulative Effect of Accounting Change	Net Income (Loss)	Earnings (Loss) Per Average Share of Common Stock Outstanding Before Extraordinary Items and the Cumulative Effect of Accounting Change	Earnings (Loss) Per Average Share of Common Stock Outstanding
First Quarter ...	**$403,279**	**$ 69,144**	**$21,248**	**$23,205**	**$.05**	**$.07**
Second Quarter.	**417,365**	**78,436**	**31,179**	**26,913**	**.15**	**.11**
Third Quarter...	**517,899**	**119,070**	**68,970**	**68,451**	**.51**	**.51**
Fourth Quarter .	**434,831**	**67,452**	**12,390**	**9,588**	**.03**	**—**
1991						
First Quarter	$ 390,538	$ 72,317	$ 24,448	$ 24,448	$ .08	$ .08
Second Quarter .	399,960	68,662	10,758	10,758	(.05)	(.05)
Third Quarter	499,508	125,121	67,247	67,247	.45	.45
Fourth Quarter ..	412,229	79,880	19,996	(170)	.04	(.14)

See Note 4 for information regarding extraordinary items recorded in 1992, due to the extinguishment of debt and for information regarding the cumulative effect of a change in accounting for power plant materials and supplies.

See Note 4 for information regarding the extraordinary item recorded in the fourth quarter of 1991, due to the discontinuation of regulatory accounting principles to the deregulated Louisiana retail portion of River Bend.

Report of Independent Accountants

To the Shareholders of Gulf States Utilities Company:

We have audited the accompanying consolidated balance sheets and statements of capitalization of Gulf States Utilities Company and subsidiaries as of December 31, 1992 and 1991 and the related consolidated statements of income (loss), cash flows, and changes in capital stock and retained earnings for each of the three years in the period ended December 31, 1992. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements 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.

As discussed in Note 2 to the consolidated financial statements, the Company has entered into an agreement, subject to regulatory approvals, to be acquired in a business combination.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Gulf States Utilities Company and subsidiaries as of December 31, 1992 and 1991 and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 1992 in conformity with generally accepted accounting principles.

As discussed in Note 4 to the consolidated financial statements, the net amount of capitalized costs for the Company's River Bend Unit 1 Nuclear Generating Plant (River Bend) exceed those costs currently being recovered through rates. At December 31, 1992, approximately $751 million is not currently being recovered through rates. If current regulatory and court orders are not modified a write-off of all or a portion of such costs may be required. Additionally, as discussed in Note 4 to the consolidated financial statements, other rate-related contingencies exist which may result in a refund of revenues previously collected. The extent of such write-off of River Bend costs or refund of revenues previously collected, if any, will not be determined until appropriate rate proceedings and court appeals have been concluded. Accordingly, no provision for write-off or refund has been recorded in the accompanying consolidated financial statements.

As discussed in Note 3 to the consolidated financial statements, civil actions have been initiated against the Company to, among other things, recover the co-owner's investment in River Bend and to annul the River Bend Joint Ownership Participation and Operating Agreement. The ultimate outcome of these proceedings cannot presently be determined. Accordingly, no provision for any liability that may result from the ultimate resolution has been recorded in the accompanying consolidated financial statements.

As discussed in Note 4 to the consolidated financial statements, the Company changed its method of accounting for power plant materials and supplies in 1992 and adopted Statement of Financial Accounting Standards No. 101 for portions of its business in 1991.

Coopers & Lybrand

Houston, Texas
February 12, 1993

Statistical Summary
For the years ended December 31

	1992	1991	1990	1989	1988
ELECTRIC DEPARTMENT					
Number of customers at year end:					
Residential	**513,819**	505,927	498,672	492,054	486,993
Commercial	**64,387**	63,522	63,044	62,469	61,958
Industrial	**4,551**	4,538	4,581	4,511	4,563
Temporary construction	**2,629**	2,011	1,805	1,638	1,477
Other	**2,926**	2,695	2,636	2,605	2,585
Total Customers	**588,312**	578,693	570,738	563,277	557,576
Sales — Kilowatt-hours (thousands):					
Residential	**6,824,670**	6,924,649	6,833,920	6,473,021	6,326,089
Commercial	**5,474,432**	5,460,326	5,388,449	5,197,356	5,023,755
Industrial	**14,396,676**	13,612,197	13,331,772	12,321,905	12,072,078
Temporary construction	**15,775**	17,144	15,399	10,759	13,133
Other	**842,034**	1,343,545	1,464,586	1,191,720	1,482,652
Total Sales	**27,553,587**	27,357,861	27,034,126	25,194,761	24,917,707
Revenue — (thousands):					
Residential	**$ 560,552**	$ 547,147	$ 523,911	$ 487,972	$ 452,538
Commercial	**400,803**	383,883	378,253	357,568	331,178
Industrial	**640,594**	580,923	577,436	539,944	510,354
Temporary construction	**1,704**	1,645	1,492	1,075	1,130
Other	**90,883**	110,361	115,543	115,315	120,513
Total Revenue	**$ 1,694,536**	$ 1,623,959	$ 1,596,635	$ 1,501,874	$ 1,415,713
Average Annual KWH Use Per Customer:					
Residential	**13,382**	13,786	13,795	13,228	13,029
Commercial	**85,538**	86,238	85,761	83,513	81,339
Industrial	**3,164,105**	2,978,599	2,944,946	2,703,951	2,717,101
Revenue Per KWH — (cents):					
Residential	**8.21**	7.90	7.67	7.54	7.15
Commercial	**7.32**	7.03	7.02	6.88	6.59
Industrial	**4.45**	4.27	4.33	4.38	4.23
Electric Energy Output — Thousands of KWH:					
Net Generated	**25,917,055**	26,581,935	26,102,741	23,955,660	25,146,780
Net Purchased and Interchanged	**4,975,260**	4,027,771	4,277,621	5,352,485	3,570,812
	30,892,315	30,609,706	30,380,362	29,308,145	28,717,592
System Peak Load — Including Interruptible Load — Megawatts	**5,247**	5,224	5,388	5,040	4,910
Total Capability, Including Contract Purchases at Time of System Peak Load (MW)	**6,709**	6,471	6,553	6,609	6,866
Load Factor	**67.0%**	66.9%	64.4%	66.4%	66.6%
STEAM PRODUCTS DEPARTMENT					
Steam Revenue (thousands)	**$ 50,315**	$ 46,418	$ 61,052	$ 69,200	$ 70,728
Electric Sales — KWH (thousands)	**1,722,151**	1,711,488	1,930,373	2,271,428	2,278,884
Steam Sales — millions of pounds	**12,682**	13,686	13,204	11,398	10,494
GAS DEPARTMENT					
Gas Revenue (thousands)	**$ 28,523**	$ 31,858	$ 32,998	$ 36,332	$ 34,036
Number of Customers at year end	**84,901**	84,005	83,164	82,681	82,510
Output — MM cu. ft. of natural gas purchased	**6,861**	6,786	6,215	7,826	7,320
Sales — MM cu. ft.	**6,985**	6,746	6,652	7,072	7,134
WEATHER DATA					
Cooling degree days (normal 2,703)	**2,596***	2,877	2,948	2,816	2,742
Percentage change from normal	**(4.0)**	6.4	9.1	4.2	1.4
Heating degree days (normal 1,841)	**1,643***	1,662	1,616	1,684	1,812
Percentage change from normal	**(10.8)**	(9.7)	(12.2)	(8.5)	(1.6)

*Estimated.

Information to Shareholders

Shareholder Questions

Shareholders having questions about their company or about their holdings may contact Shareholder Services personnel at the corporate office in Beaumont during normal business hours. Shareholders' calls made within Texas are toll-free at 1(800)392-1032, while calls from shareholders outside Texas are toll-free at 1(800)231-9266.

Prospective shareholders may also use these numbers to request financial or other information.

Notice of Annual Meeting

The 1993 Annual Meeting of Shareholders will be held at 2 p.m. Thursday, May 6, in the company's headquarters, 350 Pine Street, Beaumont, Texas. Formal notices of the meeting, proxy statements and proxies will be mailed to all shareholders on or about March 26, 1993. Shareholders are invited to attend, but if they cannot, they are urged to fill out and return their proxies.

Lost Certificates

If a GSU stock certificate is lost or stolen, written notification should be sent immediately to the company's Shareholders Service Department so that a "stop" can be placed against the missing certificate. Your notification should contain as much information as possible describing the certificate, including exact registration, certificate number and date of issue.

After a "stop" has been placed, which prevents the stock certificate from being traded, an affidavit may be requested from the transfer agent in order to obtain a replacement certificate. The affidavit must be completed, signed, notarized and returned before replacement will be made. An irrevocable indemnity bond is required in most cases.

The transfer agent should be notified promptly if a missing certificate is located.

Transfer of Stock

Whenever it becomes necessary to change the registration on a GSU stock certificate, a transfer of the stock is required. Changes in registration are necessary, for example, when a gift of stock is made, the stock is to be co-registered with another person, a name change is made or for a number of other reasons.

There is no single stock transfer procedure which will cover all possible circumstances. Some transfer situations require supporting documents to be transferred, while other might require only the signature of the shareholder authorizing the transfer to be guaranteed by either an officer of a commercial bank or a stockbroker.

The company's Shareholder Services Department may be contacted to determine the correct procedure for each type of transfer.

Stockholder Information

Stock Listing
Gulf States Utilities Co.'s common stock is traded under the symbol GSU on the New York, Midwest and Pacific Stock Exchanges.

Stock Transfer Agents
Gulf States Utilities Co.
Beaumont, Texas

First Chicago Trust Co. of
New York
New York, N.Y.

Registrars
First City Texas-Beaumont N.A.
Beaumont, Texas

First Chicago Trust Co. of
New York
New York, N.Y.

Dividend Reinvestment Plan Agent
Gulf States Utilities Co.
P.O. Box 1671
Beaumont, Texas 77704

Form 10-K
The Form 10-K Annual Report to the Securities and Exchange Commission and GSU's 1992 Financial and Statistical Report can be obtained without charge from:
Leslie D. Cobb
Vice President & Secretary
P.O. Box 2951
Beaumont, Texas 77704

Gulf States Utilities Co.
P.O. Box 2951
Beaumont, Texas 77704

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Leslie D. Cobb
Vice President &
Secretary
(32) 57

Jack L. Schenck
Senior Vice President &
Chief Financial Officer
(11) 54

James C. Deddens
Senior Vice President
Special Projects
(9) 64

Bobby J. Willis
Vice President &
Controller
(30) 56

Charles D. Glass
Vice President
Operations
(43) 64

Donald M. Clements
Vice President
Strategic Projects
(14) 43

Stephen K. Burton
Vice President &
Treasurer
(14) 39

John W. Conley
Vice President
Western Division
(34) 61

Ronald M. McKenzie
Vice President
Information Services
(26) 52

Clyde W. McBride
Vice President
Strategic Planning
(15) 40

James D. Watkins
Vice President
Baton Rouge Division
(34) 61

William J. Jefferson
Vice President
Rates & Regulatory Affairs
(12) 63

Gulf States Utilities Company Officers

Joseph L. Donnelly
Chairman of the Board,
President &
Chief Executive Officer
(13) 63

Calvin J. Hebert
Senior Vice President
Division Operations
(30) 58

Edward M. Loggins
Senior Executive
Vice President
(34) 62

Cecil L. Johnson
Vice President
Legal Services
(16) 50

James E. Moss
Vice President
Marketing
(34) 56

Ronald W. Ciesiel
Vice President
Computer Applications
(18) 40

J. Lee Miller
Vice President
Human Resources
(10) 52

J. Ted Meinscher
Vice President
Lake Charles Division
(42) 60

Amery J. Champagne
Vice President
Energy Resources
(19) 49

Philip D. Graham
Vice President
River Bend
Nuclear Group
(12) 43

Arden D. Loughmiller
Vice President
Southeast Texas Division
(31) 54

William E. Barksdale
Vice President - Engineering
& Technical Services
(35) 6[illegible]

Other Officers:

Geoffrey G. Galow
Assistant Treasurer
(12) 35

Timothy L. Morris
Assistant Secretary
(13) 41

Jasper F. Worthy
Vice President
General Services
(36) 64

( ) Years of Service Age
As of December 31, 1992

9306020327-01

Principal Offices
350 Pine St.
Beaumont, Texas
77701

Divisions
285 Liberty Avenue
Beaumont, Texas
77701

9425 Pinecroft
The Woodlands, Texas
77380

446 North Boulevard
Baton Rouge, Louisiana
70802

314 Broad Street
Lake Charles, Louisiana
70601