GULF STATES UTILITIES COMPANY
RIVER BEND STATION   POST OFFICE BOX 220   ST. FRANCISVILLE, LOUISIANA 70775
AREA CODE 504   635-6094   346-8651

May 14, 1992
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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 1991 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. In lieu of a 1991 annual report from Cajun Electric Power Cooperative, Inc., enclosed are 10 copies of an audited financial report for 1991.

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

Sincerely,

W. H. Odell
Manager - Oversight
River Bend Station

LAE/LLD/WJS

Enclosures

210025

M004
1/10 sets

U. S. Nuclear Regulatory Commission
611 Ryan Plaza Dr., Suite 400
Arlington, TX 76011

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

Mr. D. V. Pickett
U.S. Nuclear Regulatory Commission
11555 Rockville Pike
Rockville, MD 20852

GULF STATES UTILITIES COMPANY
ANNUAL REPORT 1991

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DESCRIPTION OF BUSINESS

Gulf States Utilities Co. generates, transmits and sells electricity to more than 578,000 customers in a 28-thousand square mile area that stretches 350 miles west from Baton Rouge, La., to a point about 50 miles east of Austin, Texas.

The territory served by Gulf States has a population of about 1.48 million 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.

At the end of 1991 the company was providing wholesale service to six municipalities and three rural electrical cooperatives in both states. In addition, GSU supplies steam and electricity to a large industrial customer through a cogeneration facility in Baton Rouge and is a partner in a cogeneration project, Nelson Industrial Steam Co., near Lake Charles.

Gulf States owns and operates a natural gas retail distribution system serving more than 84,000 customers in the Baton Rouge area.

As a member of the Southwest Power Pool, the company has the ability to interchange electricity with 44 members (29 full members and 15 associated members) in eight states in the South and Southwest.

In 1991, Gulf States had a peak load of 5,224 megawatts. Normal dependable capacity and firm purchased power agreements totaled 6,471 megawatts at the time of the peak.

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

ABOUT THE COVER

The people of Gulf States Utilities were instrumental in helping the company through tough times. Representative of GSU are, from left on the front cover, Jerry Irvine, lineman 1st class, Beaumont; Gayle Botley, supervisor, customer accounting, Port Arthur; Rick Hatcher, economic development agent, Conroe; Dianne Brandon, supervisor, customer services, Baton Rouge; Doug Watkins, vice president, Baton Rouge Division. On the back cover, from left, are Myra Castello, senior chemist, Nelson Coal, Lake Charles; George Kelley, senior purchasing agent, River Bend; and Bertha Rosas, customer contact clerk, Port Arthur.

Financial Highlights

	1991	1990	% Change
Operating Revenue (000)	$1,702,235	$1,690,685	.7
Operating Expenses and Taxes (000)	$1,356,253	$1,357,452	—
Net Income (Loss) (000)	$ 102,283	$ (44,282)	**
Income (Loss) Applicable to Common Stock (000)	$ 39,213	$ (107,024)	136.6
Earnings (Loss) per Average Share of Common Stock Outstanding	$0.34	$(0.99)	134.3
Dividends per Share of Common Stock	—	—	—
Average Common Shares Outstanding (000)	114,055	108,055	5.6
Number of Electric Customers (end of year)	578,693	570,738	1.4
Total Kilowatt-Hour Sales (000)	29,069,349	28,964,499	.4
System Peak Load — Megawatts	5,224	5,338	(3.0)

** percent is greater than 200.

Gulf States Utilities Service Area

The Year in Brief

As this annual report shows, Gulf States Utilities made progress in several areas during 1991 and early 1992:

- ☐ Preferred dividends were paid for the first time since 1986 and in early 1992 all preferred arrearages were declared payable March 15.
- ☐ Securities earned investment-grade ratings for the first time since 1986.
- ☐ Interest costs were cut significantly through debt reduction and refinancing activity.
- ☐ Critical rate increases were implemented in Texas and Louisiana and a potentially large write-off averted in Louisiana.
- ☐ Kilowatt-hour sales increased for the fourth year in a row.
- ☐ The company arranged for natural gas storage capacity that will enable power plant fuel to be bought when prices are lower and kept on hand for use when prices go up.
- ☐ Growth throughout the region resulted in a net increase of nearly 8,000 electric customers during the year, about 7,200 of them residential users.
- ☐ The Team City program and other economic development partnerships enabled the company to continue helping local communities attract jobs and improve the quality of life.
- ☐ Some 3,350 new jobs in such diverse fields as prisons, aircraft conversion and aquaculture were created throughout the area we serve.
- ☐ The River Bend nuclear plant was well run with an 81.6 percent net capacity factor that was well above the industry average.
- ☐ Customers contacted after having dealings with GSU gave very high marks to our employees for the service they provide.

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Report to Shareholders

Dear Fellow Shareholders:

With the new year came a new challenge. On Jan. 6, I became Gulf States' chief executive officer and, as of March 1, also will be chairman of the board. I assume these duties at a time when, as you can see on the preceding page, there are many reasons to take pride in the accomplishments of our company.

Joseph L. Donnelly
Chairman of the Board-Elect and Chief Executive Officer

If you looked at an alphabetical listing of Gulf States employees as 1991 ended, it would have started with David Abdalla and ended with Edmund Zolkiewicz. This annual report is dedicated to them and to the other 4,841 employees on that list. They deserve credit for the measured progress made by the company in 1991 and the early part of 1992.

From a shareholder's perspective, the most tangible sign of our continuing financial recovery is the fact that we are now in a position to pay off all preferred dividend arrearages on March 15. The decision to pay the $150 million in preferred dividend arrearages and related sinking fund obligations as well as the current payments due through April 15 came at the Feb. 13 meeting of the board of directors.

As of March 15, there still will be nearly $87 million in preference dividend arrearages that must be paid before the resumption of common stock dividends can be addressed. Needless to say, the board is extremely pleased with the positive steps that have been taken and remains committed to resuming common stock dividends as soon as possible.

Earnings per share of common stock were 34 cents in 1991, a definite improvement from the 99-cent loss reported in 1990 and the $1 loss sustained in 1989. Excluding the extraordinary item, 1991 earnings per share would have been 52 cents.

Successes in several areas helped clear the way for the long-awaited dividend activity that started in 1991. Our financial position improved as a result of better sales, rate increases, debt retirements that reduced interest expenses and our continuing attention to cost controls, efficiency and other self-help measures. Our employees performed superbly in all of these areas.

Although electric sales were up only slightly in 1991, it marked the fourth consecutive year that sales have been on the positive side. When you consider that sales had declined in each of the three preceding years, it is an indication that the economy in our service area has performed somewhat better than many other regions of the country.

As this report was about to go to press, another lingering cloud of uncertainty was removed as the Louisiana Public Service Commission reaffirmed, with some helpful modifications, the deregulated asset plan for the disallowed portion of the River Bend power plant. As a result of the revisions, no write-off of the deregulated portion of the plant will be required. Because of tax effects, there was a net $7.1 million charge to net income for the fourth quarter of 1991.

On another positive note, many electric utilities are grappling with a major problem that will not have a significant impact on Gulf States: how to comply with the new Clean Air Act. Gulf States estimates that during the remainder of the decade it will have to spend significantly less than utilities that expect expenditures of hundreds of millions or even billions of dollars to comply with the new requirements. The emissions from our clean-burning fuels already meet the stricter acid rain control requirements.

Our clean fuel mix also gives us an opportunity to help our customers, particularly industrial users, cope with their Clean Air Act challenges by utilizing electro-technologies designed to reduce emissions and use energy more efficiently.

I do not want to leave the impression that the road to financial recovery is clear of obstacles. Challenges abound in the form of a major lawsuit involving the Cajun Electric Power Cooperative, competition-related pressures from several directions, the threat of critical legislative and regulatory mandates at the state and federal levels and continuing uncertainty about the economy.

Our corporate priorities for 1992 and beyond will focus on dealing with these pending or potential issues while looking for new and innovative ways to meet customer needs, increase revenues and enhance your investment in this company.

As was noted in this space last year, there continue to be rumors that Gulf States is about to merge with another utility company or be acquired. Our policy continues to be that we will not comment on such rumors unless material developments require us to do so.

As we continue making progress toward financial stability, the company will be losing the services of four individuals who have played key roles in getting us this far. One, of course, is Linn Draper, who will become president of one of the nation's largest electric utilities, American Electric Power Co., on March 1. Linn's steady, calm leadership helped guide us through some difficult times, and we will miss him.

Also leaving us are three members of the board of directors who will be retiring at the annual meeting in May. John Barton, Martin Goland and Bill LeBlanc will be missed. The departures of Barton and LeBlanc are especially significant because of their long tenures on the board. John Barton has served longer than any of the current directors, since 1970. Having become a director in 1974, Bill LeBlanc has served this company with distinction. A board member since 1983, Martin Goland made his mark in a relatively short time. The company has benefited greatly from their wise counsel.

We have one new board member since last year's annual report. William F. Klausing, a former senior vice president in Irving Trust's Public Utility Division in New York, joined the board at last year's annual meeting. His background and knowledge of utility finance is proving to be a valuable asset.

In closing, I want to thank our shareholders for their continuing support during the last several years. There is still much to do, but the worst appears to be over. With the help of our hard-working employees I believe the better times we saw in 1991 will continue to get better.

Sincerely,

Joseph L. Donnelly
Chairman of the Board-Elect
and Chief Executive Officer

February 14, 1992

Linn Draper

Dear Fellow Shareholders:

This is my final, and farewell, letter as your chairman of the board. As Joe Donnelly reports elsewhere on this page, better times appear to lie ahead. I regret I will not be here to share them with you.

The decision to leave Gulf States to become president of American Electric Power was the most difficult of my life. As I said when the Jan. 6 announcement was made, my 13 years as a Gulf Stater were productive, challenging and never dull. The worst part is the people I will leave behind. I am proud of the progress made during my tenure, but it didn't come easy. It took a great deal of hard work, sacrifice and commitment on the part of all Gulf States employees. To them, I offer heart-felt thanks for their support and dedication.

To our loyal shareholders, I offer regrets that circumstances forced the company to suspend dividend payments several years ago. I know these have been painful times for many of you, and your patience and understanding is deeply appreciated.

I leave confident that Joe Donnelly, with the help of all Gulf Staters, will continue steering the company down the path of recovery and toward a brighter future. You are in good hands. Good-bye and good luck.

On Feb. 13, 1992, the GSU board of directors declared the remaining dividends on preferred stock and authorized paying the preferred stock sinking fund arrearages.

Terri Hecht, computer operator, Beaumont, watches as the computer does a test run on preferred dividend checks, the first dividends the company has paid since 1986.

Preferred shareholders will be paid almost $116 million in dividends about March 15, 1992. In 1991, this class of shareholders received dividend payments totaling about $127 million, representing 11 quarters in arrears. The March dividend payment will make the company current on preferred dividends.

The board at the February meeting also authorized paying the $28.4 million sinking fund arrearage and an additional $6 million for March and April preferred sinking fund obligations.

Preference stock dividends of about $87 million remain in arrears as of March 15, 1992. These dividends must be paid and current before the board of directors can consider paying common stock dividends.

Prior to 1991, the company had not paid a preferred or preference stock dividend since the last quarter of 1986 nor common stock dividend since the second quarter of that same year.

Members of the board of directors will continue to evaluate the financial condition of the company at each meeting. Decisions regarding the amount and timing of further dividend payments remain at their discretion.

Gulf States reported earnings of 34 cents per share of common stock for 1991, compared with a loss of 99 cents in 1990. The last year GSU had positive earnings was 1988.

Results for 1991 were helped by rate increases in Texas and Louisiana during the first quarter, reduced interest expenses and higher kilowatt-hour sales.

Earnings would have been higher had it not been for one-time charges taken during the year. A refund reserve established in advance of a January 1992 ruling in a Louisiana rate of return dispute decreased earnings by 20 cents per share. The 1991 results also were reduced by 6 cents per share as a result of a $7.1 million net charge related to the River Bend deregulated asset plan that was reaffirmed and modified by Louisiana regulators on Jan. 28, 1992.

The 1990 earnings had been impacted negatively by a $135 million after-tax charge (equivalent to $1.25 per share) for the settlement with the Southern Co. that was booked during the second quarter of 1990.

Kilowatt-hour sales increased from 29 billion in 1990 to 29.1 billion in 1991, the fourth straight year of improved sales.

Although there are no ongoing rate cases in any of the company's regulatory jurisdictions, on Jan. 21, 1992, Gulf States filed fuel cost reconciliation data required by the Public Utility Commission of Texas (PUCT).

If the PUCT adopts the proposal as filed, there will be little impact on customer rates.

Fuel costs are passed on to customers, with GSU making no profit. The PUCT requires utility companies to periodically reconcile their fuel costs and change fuel factors to reflect the actual cost of fuel.

The Louisiana Public Service Commission (LPSC) on Jan. 28, 1992, reconfirmed a deregulated asset plan to address the portion of River Bend nuclear power plant construction costs

the commission had disallowed as imprudent in December 1987. The commission did make some changes from the previously ordered plan, specifically the sharing of revenue from off-system sales. Shareholders and ratepayers will benefit equally from any revenues above a specific amount. The previous plan called for a 60-40 split between customers and shareholders.

Although no write-down is required for the deregulated portion of the plant, an increase in deferred taxes resulted in a net $7.1 million charge to net income. If the previous plan had remained in effect, the company would have written down about $128 million.

Also at the January 1992 meeting, the LPSC ordered Gulf States to make refunds to customers of about $24 million. This amount, plus $10.8 million in interest, represents the difference between a court-ordered 14 percent return on equity in 1988, which the state Supreme Court reversed, and the 12 percent return on equity ordered by the commission.

Half of the $24 million refund will be made in July 1992 and the remainder in July 1993. The interest was recorded by shortening the deferred revenue recovery period associated with the phase-in plan.

The LPSC granted the company a $16.8 million base rate increase in February 1991 as the fourth and final step of a February 1988 court-ordered phase-in plan.

In April 1991, the Louisiana Supreme Court upheld the disallowance of $1.4 billion in systemwide costs, affirmed the phase-in plan and reversed and set aside the deregulated asset plan and the return on equity issue. The state Supreme Court said the commission, not a district judge, has the authority to order the plan's implementation and that the district court erred in raising the return on equity.

The U.S. Supreme Court in early December 1991 refused to hear GSU's appeal of the Louisiana Supreme Court's decision.

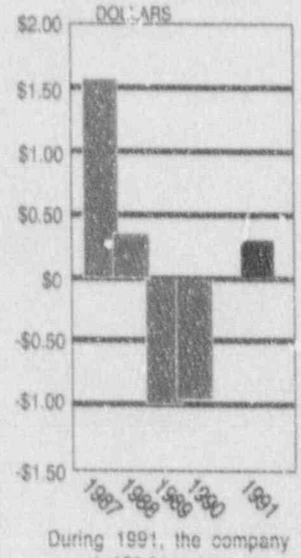
From December 1987 through February 1991, Louisiana regulators and courts have approved about $175 million in rate increases for the systemwide $1.6 billion prudent investment in River Bend.

On the other side of the Sabine River which cuts the GSU service area roughly in half, Texas regulators approved a one-time River Bend related rate increase of about $60 million in May 1988 and set aside, with no finding as to prudency, about $1.4 billion of the company's systemwide investment in River Bend (about $411 million as of Dec. 31, 1991, on a Texas retail jurisdicational basis after accumulated depreciation and related taxes). The PUCT told the company it intended to address the prudency of these costs held in abeyance in a subsequent proceeding.

Therefore, the company filed another River Bend case in March 1989, but intervenors went to court, claiming that Gulf States had only the one legal opportunity to justify River Bend costs. The Texas Supreme Court ruled in September 1990 that the PUCT was barred from addressing the prudency issue again and the U.S. Supreme Court in April 1991 refused to review the state Supreme Court decision.

In the wake of the state court decision, the company withdrew from the rate case all issues involving the costs of River Bend not in rate base and notified parties it still had a $65 million revenue deficiency.

EARNINGS per SHARE OF COMMON STOCK



During 1991, the company recorded $0.34 cents per share of earnings due to rate increases in Texas and Louisiana, reduced interest expenses and slightly higher kilowatt-hour sales.

The Texas commission on March 20, 1991, approved settlement documents granting Gulf States a $30 million base rate increase as well as other elements that had the support of most parties to the case. Two of the parties appealed the rate order and a brief hearing was conducted by an Austin district court judge in December 1991.

On Oct. 1, 1991, a state district court, in the appeal of the May 1988 rate order, held that the PUCT's decision to set aside a portion of River Bend costs had the same effect as a disallowance ruling; therefore the disallowance stands. The judge remanded a part of the same decision to the commission so that it could make rate base adjustments involving two other aspects. He ruled that the deferred expenses for River Bend and GSU's share of Big Cajun 2 Unit 3 that accrued between the time those units went into commercial operation and the date the PUCT took rate action should not have gone into rate base. This decision was based on an appellate court ruling in an El Paso Electric Co. case which is on appeal. The judge also said the commission should not have reduced GSU's deferral balance by $1.50 for each $1 of revenue collected after an interim rate increase went into effect in 1987.

A motion for a new trial failed for lack of action by the judge on Dec. 16 and the company has appealed to the 3rd Court of Appeals in Austin. GSU wants the case sent back to the PUCT so it can make a final ruling on River Bend prudence based on evidence placed in the record during the original rate case which was decided in 1988.

Sam Richardson, economic development agent, Baton Rouge, checks through data bases for information being sought by an industry interested in the area.

The company contends there was sufficient evidence about River Bend costs for the hearing examiners to make recommendations and that the PUCT should not have set aside the $1.4 billion in systemwide costs.

The long-standing purchased power contracts dispute between GSU and the Southern Co. came to a formal close on Nov. 7, 1991, when officials of the two companies signed settlement documents.

The two utilities had agreed to settle the lawsuit in June 1990, but the terms had to be approved by both boards of directors, various regulatory agencies and the federal court with jurisdiction over the case. The terms of the settlement are the same as discussed in the 1990 Annual Report.

The lawsuit filed by the Cajun Electric Power Cooperative against Gulf States in June 1989 is still pending in a Baton Rouge federal district court. The co-op, which owns 30 percent of the River Bend nuclear power plant, claims, among other things, that Gulf States misrepresented the costs involved in building the plant in order to lure Cajun into financial participation in the project. GSU believes the suit is without merit and is contesting it vigorously.

On Dec. 2, 1991, Cajun filed another lawsuit against GSU in federal court to block demands by Gulf States for payment of its share of the costs of making certain repairs at River Bend.

Cajun informed Gulf States in September that it would not participate in the cost of repairing a corrosion problem in the nuclear plant's service water system and converting the system to a closed loop so it no longer takes in water from the Mississippi River. Nor, Cajun said, will it help pay for repairs to a cracked feedwater nozzle discovered later. Total estimated cost for the repairs

and improvements is about $60 million.

Cajun said in the lawsuit that it has a contractual right not to pay plant maintenance expenses and that it would have to issue new debt if it paid its share of the repairs, forcing it to default on its debt restructuring agreement with the Rural Electrification Administration.

The company, which is exploring available legal remedies, will certainly make the repairs to River Bend regardless of whether Cajun pays its share of the costs.

During 1991, GSU's first mortgage bonds were upgraded to investment grade by both Standard & Poor's and Moody's. This is the first time since 1986 that Gulf States' securities have been investment grade. In addition, the company took advantage of falling interest rates and initiated a series of refinancings that is continuing in 1992.

The company sold $300 million in first mortgage bonds in January 1992. A total of $150 million in 10-year bonds was sold at an interest rate of 8.21 percent, with the remaining $150 million 30-year bonds at an 8.94 percent interest rate.

The net proceeds will be used to retire outstanding first mortgage bonds with interest rates ranging from 13.5 percent to 16.8 percent, which means the company's interest expense is being significantly reduced. The notice of redemption was issued Jan. 22, 1992.

The redemption premiums associated with the various series ranged from zero to about $9 million. The accrued interest on the bonds was paid from general corporate funds.

In November, Gulf States reoffered $94 million in pollution control revenue bonds for the Parish of West Feliciana where the River Bend nuclear power plant is located. The bonds, which mature in 2014, were converted from a daily adjustable rate to a fixed interest rate of 7.7 percent. The company intends to remarket $109 million of other variable rate pollution control bonds during 1992.

In July 1991, GSU sold $200 million in debentures at a 9.[illegible]2 percent interest rate. Proceeds from the sale were used to refund a term loan facility with a group of banks.

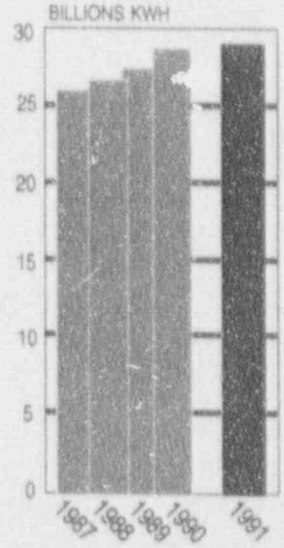
A major goal of Gulf States' marketing program is to promote full use of existing generating capacity through business development while helping customers use energy wisely to minimize GSU's need for future power plant investment.

GSU worked closely with large industrial customers to develop mutually beneficial long-term plans. These strategies helped the company attempt to meet existing customers' needs and serve new customers in the most profitable manner possible—through maximum utilization of existing capacity.

Despite a widespread economic recession during 1991, the economy in GSU's service area remained fairly stable and Gulf States' overall electric sales increased slightly from 1990 levels when sales were up 5 percent over the previous year.

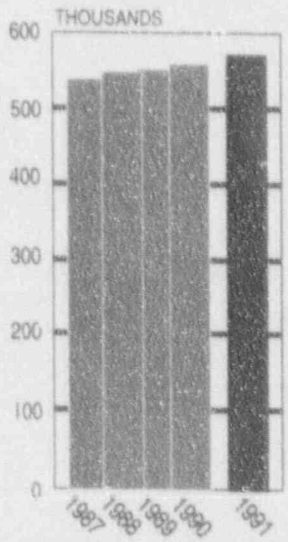
Industrial sales increased 2.1 percent over 1990 levels, fostered by the development of stronger partnerships between GSU and industrial customers. Sales to commercial and residential customers also rose in 1991, due in large part to a concerted direct sales effort by company

ELECTRIC SALES



Electric sales have increased for the fourth consecutive year. Sales increased in the residential, commercial and industrial classes during 1991.

ELECTRIC DEPARTMENT CUSTOMERS



The 7,955 new electric customers GSU gained during 1991 amounted to a 1.4 percent increase, continuing the growth trend begun in 1987.

employees. About 21 percent of all Gulf States' employees participated in the "Reddy Referrals" program which rewards employees for attracting additional energy efficient sales. These Reddy Referrals contributed $6.4 million in new base revenue for Gulf States.

In addition to improved sales, GSU saw a 1.4 percent increase in the number of customers connected to company lines during 1991. The residential customer class grew by 1.5 percent, with growth experienced throughout the service area, but highest in the area north of Houston.

Extensive economic development efforts on the part of Gulf States and communities served by the company played a significant role in attracting new businesses and industries to the service area.

GSU's Team City community development program was extremely successful in helping 81 participating cities, counties and parishes in the service area retain existing employers and professionally market themselves to new businesses and industries. Many of these communities gained new jobs and diversified their local economies during 1991, while at the same time helping to diversify the economy of Gulf States' service area as a whole.

The Team City program, in conjunction with numerous other economic and industrial development endeavors, helped attract 26 new businesses and industries and assisted 35 others to expand during 1991. They brought with them more than 3,350 new jobs in such diverse fields as prison construction and operations, apparel manufacturing, aircraft conversion and aquaculture.

John Bernard, electrical designer, Beaumont, looks over the marsh GSU employees are helping restore for the benefit of waterfowl.

This diversity, coupled with modest but steady growth projected for the region's petro-chemical industry, should spell continued growth and increased stability for the region's economy as a whole. And GSU's ability to economically power such growth with existing capacity—and little expected need for capital investment in power plant construction for years to come—points toward increased profitability for the company.

During 1991, the River Bend nuclear power plant posted a net capacity factor of 81.6 percent, well above the industry average. This is the plant's actual generation stated as a percentage of its maximum capability.

The capacity factor for the plant from the date of commercial operation, June 16, 1986, through Dec. 31, 1991, was 69 percent, which is considered good solid performance.

Also demonstrating the unit's positive performance was equivalent availability statistics showing that River Bend was available for service 83 percent of the time during 1991. Equivalent availability since commercial operation was 71 percent.

In 1991, River Bend generated more than 6.6 billion kilowatt-hours of electricity and provided 16 percent of the company's total energy requirements. From the time the plant went into commercial operation through the end of 1991, it had produced 31.4 billion kwh.

GSU has a 70 percent ownership in the 936-megawatt unit, located near St. Francisville, La. Cajun Electric Power Cooperative owns the remaining 30 percent.

During the fourth refueling outage at River Bend, scheduled to begin March 15, 1992, GSU will chemically clean the service water system and convert it from an open to a closed loop system. This should serve as a long-term solution to the corrosion problem in the system.

Also during the outage, a cracked feedwater pipe weld that the company has been monitoring will be repaired and steps will be taken to reduce the radiation levels in certain areas of the plant by chemically cleaning the reactor's recirculation loop.

Because of the service water cleaning and conversion, and the weld repair and chemical cleaning of the recirculation system, this outage is now expected to last 156 days, compared with the 60 to 90 days a refueling outage normally takes.

Although River Bend will be out of service during part of the summer, the time of year when electricity use is highest, the company believes it has enough other generating capacity, supplemented by off-system purchases, to adequately cover the anticipated summer peak load. As always, GSU buys power from other utilities when economical.

River Bend received a good report from the Nuclear Regulatory Commission during 1991. In the NRC's Systematic Assessment of Licensee Performance (SALP) issued in mid-June, River Bend received the highest possible ranking in two of seven operational areas.

The plant received Category 1 ratings—the highest—in plant operations and in emergency preparedness. The other five areas — radiological controls, maintenance and surveillance, security, engineering and technical support and safety assessment and quality verifications—earned Category 2 ratings. River Bend received no Category 3 rankings, the lowest.

Construction of a new natural gas storage facility south of Beaumont is underway. Gulf States will not be the owner, but will have full use of Spindletop Gas Storage.

When it begins operations in the fall of 1992, the company will purchase gas at lower prices for storage. When prices rise, the gas will be pulled out for usage. The company will be able to supply needed fuel to its plants when loads peak and do it economically.

The gas suppliers like this, too, since it can help levelize GSU's demands on their systems.

Significant changes in top management at Gulf States occurred during the first month of 1992.

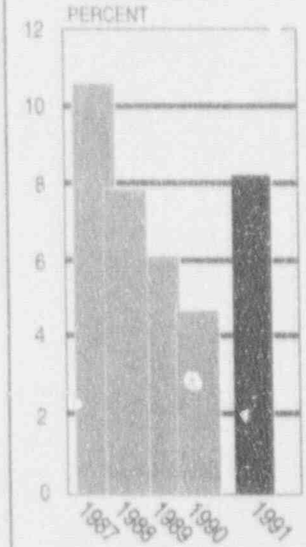
Joseph L. Donnelly was elected chief executive officer of GSU, effective Jan. 6, 1992, and on March 1 will also become chairman of the board. He succeeds E. Linn Draper who is leaving GSU to become president of Columbus, Ohio-based American Electric Power Co., the nation's second largest electric utility, on March 1.

Donnelly joined GSU in April 1979 as senior vice president of finance and chief financial officer and became executive vice president later that same year. He was elected senior executive vice president in 1986 and was elected to the Gulf States' board of directors that same year.

Replacing Donnelly as chief financial officer is Jack L. Schenck who will also hold the title of senior vice president. He has been GSU's treasurer since he joined the company in 1981 and was named vice president in 1985.

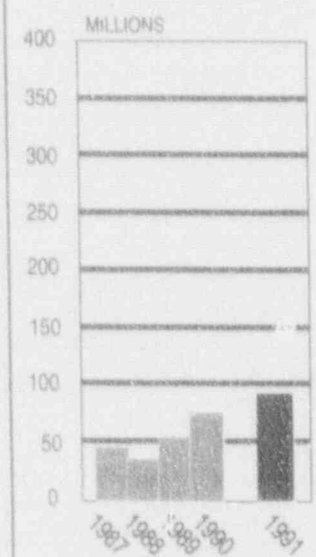
Stephen K. Burton was named vice president and treasurer, replacing Schenck, and Clyde W. McBride was promoted from assistant treasurer to vice president of strategic planning. Geoffrey G. Galow became assistant treasurer.

RETURN on AVERAGE CAPITALIZATION



Return on average capitalization increased due to the improved earnings in 1991.

CONSTRUCTION EXPENDITURES



Construction expenditures have been kept to minimum levels since the completion of River Bend in 1986.

Also named to new positions in January were A.F. "Tony" Gabrielle, who was moved from vice president of computer applications to vice president of special projects. Ronald W. Ciesiel succeeds him as vice president of computer applications.

Steve Bagley, senior draftsman, Beaumont, is one of many GSU employees who volunteer their time to help in local schools.

On Nov. 22, 1991, GSU submitted to the LPSC plans for implementing about 120 recommendations made by the firm that conducted a management audit of the company that ended in 1991.

Kennedy & Associates of Atlanta was hired by the LPSC to look at ways GSU could cut costs. The results were released in April 1991 and GSU has agreed to implement, or already has implemented about half the recommendations.

Being earth-friendly is more than a catchy slogan for Gulf States. The company has depended upon a clean fuel—natural gas—for decades. The more recent additions of low-sulfur Western coal and nuclear diversified the fuel mix, while continuing the tradition of clean fuels.

Today, the company's natural gas, nuclear and low-sulfur coal power plants meet the tough new sulfur dioxide emissions requirements of the 1990 federal Clean Air Act. Gulf States believes that during the '90s it will be spending significantly less to meet the new requirements than those utilities that rely heavily on high-sulfur coal and oil. Emission from the company's power plants already meet the stricter new acid rain requirements.

On another environmental front, Gulf States has carried out aquaculture demonstration projects for about four years, including helping one school district develop an aquaculture curriculum to raise catfish and working with another to build a raceway for raising hybrid striped bass.

Several of the aquaculture projects have focused on growing commercially banned species of fish, such as redfish, and all of the projects have offered economic development possibilities for the company.

Aquaculture is a natural for GSU since it is the fastest-growing segment of the agricultural economy and the GSU service area offers most of the resources needed to support this growing industry.

Some GSU employees are bringing to reality their dream of filling the skies near Sabine Station with ducks. The power plant, located near Bridge City, Texas, was previously surrounded by a deteriorating saltwater marsh.

Since 1989, GSU employees have helped provide additional Texas Gulf Coast roosting areas for migratory waterfowl by transforming two ponds at the site into a freshwater marsh.

GSU's 90-acre Waterfowl Management Area, made up of two 45-acre ponds, joined the Gulf Coast Venture of the North American Waterfowl Management Plan in 1989, becoming the first large corporate member. The grassroots volunteer effort aims at giving ducks and geese a place to rest and feed so that when they fly back north in the spring, they'll be healthy and ready to breed.

Improvements carried out on a volunteer basis by the employees have helped to significantly raise the duck population at the site.

GSU does more than just dabble in environmental "projects." The company had an Environmental Affairs team long before it became fashionable. In the early 1970s the company recognized that protecting the world around us was an important priority and began hiring environmental experts.

Today, the company has a staff of nine professionals with training and experience in environmental science, biology, geology and chemistry. The group works with environmental coordinators in the company's five operating divisions and eight generating plants to help GSU meet its environmental obligations.

Environmental Affairs obtains the many permits and registrations required by various federal and state agencies, conducts environmental compliance audits, does special projects and recommends pro-active steps the company can take to demonstrate its environmental commitment.

Although Gulf States stopped making corporate contributions to worthwhile charities when dividends were halted, employees have continued to give of their time and talent.

Management Audit Completed

The management audit completed in 1991 for the Louisiana Public Service Commission was performed by Kennedy & Associates, an Atlanta-based firm that has opposed the company in a series of rate and regulatory proceedings in recent years. Considering the frequent criticism leveled by the firm at Gulf States and its management, its management audit conclusions about the company's executive management are interesting:

"GSU has a well organized, experienced executive management team that is qualified to perform its responsibilities. Executive management appears to have a good understanding of the interrelated processes necessary to develop an effective organization."

GSU employees have a long history of participating in formal fundraising activities for worthy causes, such as United Way, March of Dimes and American Heart Association. In recent years, concerned employees have expanded their range of activities to include more person-to-person giving. GSU has a community relations coordinator who helps match up employees who want to help with individuals and organizations that need their assistance.

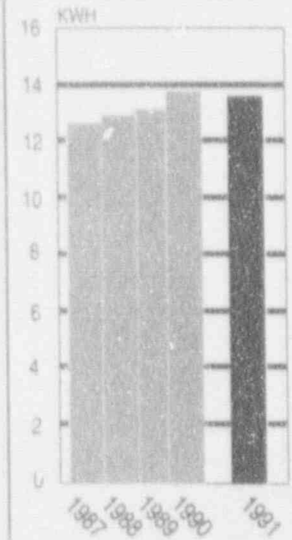
GSU employee volunteer activities include:

- "Adopting" an 84-year-old woman in Cleveland, Texas.
- Providing on-the-job training for 8th-graders in Lake Charles, La.
- Donating cuddly "Reddy Teddy" bears for traumatized children in Port Arthur, Texas, and Huntsville, Texas.
- Using their "first responder" training at River Bend for the Wakefield, La., Volunteer Fire Department.
- Forming a musical variety group, the "Reddy Rhythms," that performs at retirement homes and shopping malls in the Beaumont-Port Arthur area.

Employment practices for the 4,843 Gulf States employees are guided by the principles of equal opportunity for all. It is partially through the affirmative action programs that the company has been able to hire skilled personnel from all community sectors.

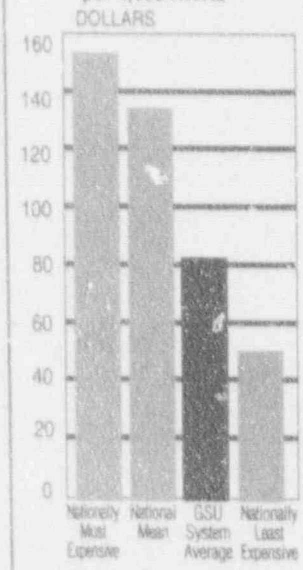
Fair employment policies assist GSU in developing its human resources to serve our customers more effectively.

AVERAGE RESIDENTIAL ELECTRIC USE (per customer)



Average residential electric use per customer remained strong, despite a slight decrease from the record amount in 1990.

RESIDENTIAL COST per 1,000 KWHs*



(*As of July 1, 1991)

GSU's residential rates remain lower than the national average and are competitive in Texas and Louisiana.

The foregoing portion of this report is intended to present information the company believes may be of interest to shareholders. For purposes of making investment decisions, the more complete information contained in the company's Annual Report on Form 10-K and other current reports filed with the Securities and Exchange Commission should be consulted.

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 certified public 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 46. 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 Cash Dividends Per Share

For the years ended December 31

1991	High	Low	Cash Dividends Paid Per Share
First Quarter	$12¼	$10⅝	$ —
Second Quarter	12	9	—
Third Quarter	10¾	9¼	—
Fourth Quarter	10⅝	8½	—

1990	High	Low	Cash Dividends Paid Per Share
First Quarter	$12⅝	$11	$ —
Second Quarter	12⅛	9⅞	—
Third Quarter	12⅛	9¼	—
Fourth Quarter	11	8⅝	—

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, 1991, was 53,368.

Financial Information

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

For the Years Ended December 31	1991	1990	1989	1988	1987
Operating Revenue	**$1,702,235**	$1,690,685	$1,607,406	$1,520,477	$1,432,586
Income (Loss) Before Extraordinary Item and the Cumulative Effect of Statement of Financial Accounting Standards (SFAS) No. 90 in 1988	**122,449**	(44,282)	13,251	117,512	241,101
Net Income (Loss)	**102,283**	(44,282)	(45,573)	103,143	241,101
Income (Loss) Applicable to Common Stock	**39,213**	(107,024)	(108,412)	40,079	178,091
Earnings (Loss) Per Average Share of Common Stock Outstanding Before Extraordinary Item and the Cumulative Effect of SFAS No. 90 in 1988	**.52**	(.99)	(.46)	.50	1.65
Earnings (Loss) Per Average Share of Common Stock Outstanding	**.34**	(.99)	(1.00)	.37	1.65
Dividends Per Share of Common Stock	**—**	—	—	—	—
Return on Average Common Equity	**1.99%**	(5.44)%	(5.29)%	1.95%	9.29%
As of December 31					
Total Assets	**$6,911,492**	$6,863,269	$6,807,894	$6,941,531	$6,907,453
Long-Term Debt and Preferred Stock Subject to Mandatory Redemption	**2,656,562**	2,512,743	2,801,860	2,990,934	3,090,977
Capital Lease Obligations (Current and Non-current)	**138,133**	161,065	180,552	98,852	187,640
Book Value Per Share (reduced for all Preferred and Preference Stock Dividend Arrearages)	**16.77**	16.81	17.80	18.80	18.43
Capitalization Ratios:					
Common Shareholders' Equity	**41.1%**	41.2%	39.8%	39.3%	37.8%
Preferred and Preference Stock	**12.2**	14.4	12.9	11.7	11.1
Long-Term Debt	**46.7**	44.4	47.3	49.0	51.1
	100.0%	100.0%	100.0%	100.0%	100.0%

See Notes 2 and 3 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

The Company's financial position was strained from 1986 through 1990 as a result of the inability to obtain rate relief on the Company's entire investment in River Bend Unit 1 (River Bend). Dividends on the Company's common stock were suspended in 1986, and dividends on the preferred and preference stock were suspended in 1987. Beginning in 1987, the Company failed to meet its sinking fund requirements on preferred stock and has not met any such sinking fund requirements through 1991. Also, in 1986, the Company and Southern Company (Southern) began litigating disputes relating to certain purchase power contracts providing for purchases by the Company of capacity and energy from Southern. The Company had significant amounts of debt maturing in each of the years 1988-1991, which put additional pressures on its cash flow.

However, through improving sales, reductions in capital requirements, strict cost controls, some external financing arrangements and the rate relief granted, the Company was able to meet its immediate cash requirements for 1986 through 1990.

In 1991, the Company's financial position continued to improve. The Company sold $200,000,000 of debentures in July 1991, consummated the Southern settlement in November 1991, and remarketed $94,000,000 of pollution control bonds in December 1991 that were secured by letters of credit that were due to expire in December 1991. The Company began to reduce the dividend arrearages on its preferred stock, paying the equivalent of eleven quarters of dividends in 1991.

While litigation with Southern was finally consummated in 1991, additional significant litigation and regulatory contingencies continue to exist. 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 2 and 3 to the Consolidated Financial Statements that certain litigation and regulatory contingencies exist and the possible consequences if such contingencies were ultimately resolved adversely to the Company.

Results of Operations

Net income and earnings per share of common stock outstanding for 1991 increased when compared to prior years 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 net of tax reserve, 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 portion of the deregulated part of River Bend.

The 1990 net loss and loss per average share of common stock outstanding resulted primarily from a $135,310,000 net of tax charge recorded during the second quarter of 1990, for the settlement with Southern as discussed in Note 2 to the Consolidated Financial Statements. Excluding the cost of the Southern settlement, results of operations improved during 1990. Increased kilowatt-hour sales and reduced interest charges contributed to the improved performance.

As of December 31, 1991, the Company has not recovered a significant amount of the investment or received any return associated with the portion of River Bend disallowed in the Louisiana rate order of December 15, 1987, and included in the deregulated asset plan and the portion of River Bend placed in abeyance as part of the Texas rate order which went into effect July 23, 1988. Future earnings will continue to be limited as long as the limited recovery of the investment and lack of return continues.

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 deferred costs related to River Bend, 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 3 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.

The Company's results in 1989, and to a significantly lesser extent in 1990 and 1991, have been affected by amounts recorded in accordance with phase-in plans and amounts recorded in accordance with accounting orders issued in 1986 by regulators allowing the Company to defer, for financial reporting purposes, those expenses incurred in connection with the operations of River Bend, the cost of buying back power from Cajun Electric Power Cooperative, Inc. (CEPCO), and to record a non-cash carrying charge on the Company's investment in River Bend not already reflected in rate base and the subsequent amortization of those costs. Current amortization schedules indicate

that 1992 amortization of such costs will be approximately $32,000,000.

Rate Matters

***Texas Retail Jurisdiction* (Regulator — Public Utility Commission of Texas [PUCT])**

In October 1990, hearings on a base rate request filed in March 1989 were restarted before the PUCT. Settlement negotiations began on February 13, 1991, with various intervening parties. On March 22, 1991, the PUCT issued an order consistent with the terms of a proposal (Joint Recommendation) offered by most of the parties to the rate case that provided for a $47 500,000 rate increase, consisting of a $30,000,000 increase in base rates and an increase of $17,500,000 in fuel revenues. Among other things, the Joint Recommendation also required the Company to refund approximately $25,400,000 of fuel over-recoveries to ratepayers over a twelve month period and allowed the Company to retain approximately $16,800,000 in franchise tax refunds. The Company was also required to refund approximately $?,562,000 of revenue (including interest), collected subject to refund as part of an approximate $65,089,000 base rate increase that was placed in effect on December 11, 1990 under bond. The Company also agreed not to file a new base rate request for two years, with certain exceptions.

In a May 1988 rate order, the PUCT set aside in abeyance $1.4 billion of the River Bend plant investment and $157,000,000 of related deferred River Bend 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. The Company appealed the order. The Texas Supreme Court subsequently 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 future rate cases. 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, 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 recent decision regarding El Paso Electric Company's similar deferred costs. The court remanded the case to the PUCT with instructions as to the proper handling of the deferred cost issues.

As of December 31, 1991, on a Texas retail jurisdictional basis, the disallowed River Bend plant costs were approximately $19,000,000, and the River Bend plant costs held in abeyance totaled approximately $411,000,000, both net of accumulated depreciation and related taxes. The deferred River Bend costs associated with the portion of the investment held in abeyance as of December 31, 1991, amounted to approximately $161,000,000, net of taxes. Deferred River Bend costs, which were allowed in rate base in Texas, were approximately $107,000,000, net of taxes, as of December 31, 1991. The Company estimates it collected approximately $85,000,000 of revenues, as of December 31, 1991, as a result of the previously ordered rate treatment of these deferred costs and currently estimates that it collects revenues associated with such deferred costs of approximately $2,300,000 monthly, or $28,000,000 annually, from ratepayers in Texas.

Deferred costs associated with Big Cajun 2 Unit 3 totaled approximately $4,369,000, net of taxes, as of December 31, 1991, of which approximately $1,880,000, net of taxes, were included in rate base by the PUCT. The remaining $2,489,000, net of taxes, of deferred costs were not included in rate base and were included in the appeal to the district court.

The Company's motion for a retrial was denied, and on December 18, 1991, the Company appealed the October 1, 1991 decision of the district court. The El Paso case upon which the decision is in part based is also in the process of being appealed. No assurance can be given as to the timing or outcome of any such actions. However, management believes, based on advice from legal counsel of record in the proceeding, there is a reasonable possibility of a favorable decision on the appeal of the district court order. Pending ultimate resolution of these cases, the Company has made no write-offs for the previously disallowed portion of River Bend plant costs, the River Bend plant costs held in abeyance, or the deferred costs discussed above. If the district court decision is ultimately upheld, a write-off will 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 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 — Louisiana Public Service Commission [LPSC])**

On February 26, 1991, the LPSC granted the Company a $16,800,000 base rate increase, effective March 1, 1991, as the fourth and final step of the February 18, 1988 court-ordered phase-in plan.

On April 5, 1991, the Louisiana Supreme Court affirmed the district court order of October 11, 1989, which upheld the LPSC finding that the Company's 1979 decision to restart construction of River Bend was imprudent, and which disallowed $1.4 billion of the River Bend plant investment. The Louisiana Supreme Court reversed and set aside the district court's order which implemented the deregulated asset plan for the $1.4 billion of River Bend plant investment. On December 9, 1991, the United States Supreme Court refused to hear the Company's appeal of the Louisiana Supreme Court's decision.

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 Statement of Financial Accounting Standards (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 state net operating loss carryforward position the Company is in, a previously unrecorded offsetting state tax benefit of $13,100,000 operations-related tax loss carryforward ($.12 per share of common stock) is included in "Income Taxes — State."

On January 28, 1992, the LPSC also 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 ($13,200,000 net of tax) 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 ($9,864,000 net of tax) in the fourth quarter of 1991. The $24,143,000 principal will be refunded in two steps, one-half in July 1992 and one-half in July 1993. Interest was recorded as credits to the deferred River Bend revenue requirement associated with the phase-in plan.

Liquidity, Financings, and Capital Resources

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 1991-1989:

	1991	1990	1989
		(In thousands)	
Funds Provided By			
Net operating activities	$470,147	$363,788	$220,071
Sale of debentures	200,000	—	—
Sale of nuclear fuel — River Bend fuel lease	—	—	114,931
Existing cash and cash equivalents	—	930	—
Other	14,141	2,513	6,642
Total	$684,288	$367,231	$341,644
Funds Used For			
Capital expenditures	$ 87,470	$ 73,020	$ 74,888
Retirement of long-term debt and deferred River Bend construction and continuing services commitments	333,082	219,454	143,170
Payment of lease obligations	36,890	44,110	27,552
Payment of preferred dividends	127,398	—	—
Investment in cash and cash equivalents	96,473	—	95,125
Other	2,975	30,647	909
Total	$684,288	$367,231	$341,644

As of December 31, 1991, the Company had available $100,000,000 under a bank credit agreement as described in Note 12 to the Consolidated Financial Statements, which will expire February 28, 1992. The agreement contains restrictions upon additional borrowings, payment of dividends, and other actions of the Company, with certain exceptions. The Company is currently negotiating for a new short-term line of credit, which may include a restriction on the payment of common dividends.

As of December 31, 1991, the Company had approximately $103,000,000 of long-term debt scheduled to mature in 1992. In addition there are $109,000,000 of pollution control bonds that are secured by letters of credit which expire at various times in 1992. If the letters of credit are 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.

In January 1992, the Company refinanced $282,878,000 principal amount of outstanding higher cost first mortgage bonds with the proceeds of two new first mortgage bond issues totaling $300,000,000. The Company intends to refinance additional higher cost first mortgage bonds during 1992, if possible. The Company's funds provided from operations have continued to improve over the last several years, and 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, financial market, or banking conditions, or adverse developments with respect to contingencies to which the Company is subject.

The Company's ability to arrange external financing was materially affected by its weak financial position during 1986 through 1990, but improved during 1991, as a result of the improvement in the Company's financial position. 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 15 months preceding a new debt issuance. Based upon the results of operations for the year ended December 31, 1991, and/or on the basis of previously retired debt, the Company believes it could issue $349,000,000 of additional first mortgage bonds, in addition to the amount presently outstanding (assuming an interest rate of 9 percent for additional first mortgage bonds). First mortgage bonds in a greater amount may also be issuable for the refunding of outstanding 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, 1991, 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; however, it is unlikely that the Company could market any common, preferred, or preference stock in the near future since dividends on preferred and preference stock are in arrears and dividends on the common stock cannot be paid until all preferred and preference stock dividend and sinking fund arrearages are satisfied.

Payment of current dividends on all stock is at the discretion of the Board of Directors and depends upon its continuing evaluation of the financial condition of the Company. However, it is an objective of the Company to pay all dividends in arrears on preferred and preference stock, all sinking fund obligations on preferred stock, and to resume payment of dividends on common stock as soon as the Board believes the Company is financially able to do so.

See Note 15 to the Consolidated Financial Statements for information regarding the February 13, 1992 declaration by the Board of Directors of preferred stock dividend and sinking fund arrearages.

Significant Litigation, Risks, and Environmental Issues

As discussed below, and more fully in Note 2 to the Consolidated Financial Statements, significant litigation and other risks exist. The risks which management believes to be the most significant are discussed below.

CEPCO Litigation. As discussed in Note 2 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. The Company believes the suit is without merit and is contesting it 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. During 1991, the Company increased its reserve for cleanup of sites by $14,550,000.

Several class action and other suits have been filed in state and federal courts seeking relief from the Company and others for damages allegedly caused by the disposal of hazardous waste and for asbestos-related disease which allegedly occurred from exposure on Company premises. One hazardous waste related suit claims approximately $15 billion of damages from the defendants. While the amounts at issue in these cleanup efforts and suits may be very substantial sums, the Company presently believes that its financial condition will not be materially adversely affected by the outcome of those suits.

In 1990, amendments to the Clean Air Act became law. The effects on the Company are not expected to be substantial due primarily to the Company's clean fuel mix.

Operating Revenue

Operating revenue increased by 1 percent during 1991, when compared to 1990, by 5 percent during 1990 when compared to 1989, and by 6 percent during 1989, when compared to 1988. The components of the changes in operating revenue are detailed below:

	Increase (Decrease) From Prior Year		
	1991	1990	1989
		(In thousands)	
Change in base rates	$ 46,927	$12,894	$38,289
Provision for rate refund — Louisiana	(24,143)	—	—
Fuel cost recovery	(21,842)	19,824	29,281
Sales volume and other	10,608	50,561	19,359
	$ 11,550	$83,279	$86,929

Rates. The changes in base rates shown above reflect rate orders, settlement agreements, and rate changes implemented during the period from 1988 through 1991. The Company implemented permanent rate increases in each of the years 1988-1991.

As discussed in Note 3 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. Total kilowatt-hour sales increased less than 1 percent during 1991, when compared to 1990. This increase follows a 5 percent increase during 1990 when compared to 1989, and a 1 percent increase in sales during 1989, when compared to 1988. Changes in the three major kilowatt-hour sales categories are shown in the following table:

	Increase from Prior Year		
	1991	1990	1989
Residential	1%	5%	2%
Commercial	1	4	3
Industrial	2	8	2

See the Statistical Summary on page 47 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 then 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 have increased over the last several years. Kilowatt-hour sales, changes in kilowatt-hour sales, and related revenue within the industrial class are detailed below:

	1991	1990	1989
Sales — Kilowatt-hours		(In thousands)	
Full cost of service based rates	10,188,808	10,265,998	10,210,280
Non-full cost of service based rates	3,423,389	3,065,774	2,111,625
Total industrial	13,612,197	13,331,772	12,321,905

	Increase (Decrease) from Prior Year		
Changes in Kilowatt-hour Sales	1991	1990	1989
Full cost of service based rates	(1)%	1%	(6)%
Non-full cost of service based rates	12	45	77
Total industrial	2	8	2

	1991	1990	1989
Revenue		(In thousands)	
Full cost of service based rates	$475,976	$480,280	$470,401
Non-full cost of service based rates	104,947	97,156	69,543
Total industrial	$580,923	$577,436	$539,944

In 1992, the Company anticipates a decrease in non-full cost of service industrial sales and an increase in full cost of service industrial sales due to new customers; 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, $11,200,000 and $11,300,000 during 1991, 1990, and 1989, respectively.

Steam Department Electric Sales. The Company has for a number of years produced steam at its Louisiana Station No. 1 in Baton Rouge and sold such steam, along with the cogenerated electricity, to industrial customers located adjacent to Louisiana Station. Electric power requirements of these customers in excess of the by-product electricity have been met by the Company with power from the Company's system power grid.

In June 1990, the remaining steam customer replaced a substantial portion of power previously provided from the Company's grid with power from additional cogeneration facilities. Non-fuel revenues fro sales of electric power off the Company's system power grid to the steam customer amounted to approximately $13,700,000, $19,400,000, and $22,800,000 during 1991, 1990, and 1989, respectively. Fuel revenues from sales of electric power off the Company's system power grid to the steam customer amounted to approximately $4,90 00, $12,500,000, and $22,300,000 during 1991, 1990, and 1989, respectively.

Operating Expenses and Taxes

Fuel and Purchased Power. 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.

Fuel expense increased 11 percent during 1990, when compared to 1989, due to increased use of Company-owned generating units. This increase was offset in part due to a decrease in the Company's average fuel cost.

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

Purchased power expense decreased 12 percent during 1990, when compared to 1989, due to reduced capacity payments to CEPCO under the buyback agreement, as discussed in Note 13 to the Consolidated Financial Statements, and decreased purchases resulting from the availability of Company-owned generating units.

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

	1991	1990	1989
Cost of fuel consumed (cents per KWH)			
Natural gas	1.79	1.91	1.96
Coal	2.08	2.11	2.12
Nuclear	1.24	1.28	1.33
Combined	1.73	1.83	1.89
Cost of purchased power (cents per KWH)	3.97	4.70	4.24

	1991	1990	1989
	(kilowatt-hours in thousands)		
Net generation (excluding steam department electric generation)	25,233,164	24,782,548	22,759,532
Purchased power	4,010,461	4,230,143	5,373,912
Total electric energy requirements	29,243,625	29,012,691	28,133,444

	1991	1990	1989
Net generation (ding steam department generation)			
Natural	57%	61%	58%
Coal	13	11	11
Nuclear	16	13	12
	86	85	81
Purchased power	14	15	19
Total electric energy requirements	100%	100%	100%

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

A cussed in Note 2 to the Consolidated Financial S ements, the Company will be making certain repairs and improvements to a service water system and repairs to a feedwater nozzle at River Bend during a refueling outage which will begin in the spring of 1992. These repairs and improvements will extend the refueling outage beyond previous outage periods. CEPCO has informed the Company that it will not participate in funding its share of the costs related to the service water system and feedwater nozzle. Due to the extended outage and repairs discussed above, in addition to the possibility that the Company will have to fund CEPCO's share of the costs, operations and maintenance expense could increase by approximately $7,000,000 during 1992, when compared to 1991.

Other operations and maintenance expenses decreased slightly during 1990, as expenses associated with the River Bend refueling outage were less in 1990 than in 1989. That decrease was somewhat offset due to severance pay and early

retirement benefits associated with the workforce restructuring in January 1990.

Other operations and maintenance expenses increased during 1989, when compared to 1988, due primarily to increased payroll and benefit charges, expense of $2,738,000 associated with the cleanup of two hazardous waste disposal sites, and increased costs associated with the refueling outage for River Bend. In addition, operations expense also increased during 1989, due to a tentative settlement reached with CEPCO regarding the overhead related to administrative and general expenses for River Bend, which resulted in the Company increasing its operations expense by $8,310,000.

Taxes. Federal income taxes charged to operating expenses decreased in 1991, when compared to 1990, as detailed in Note 4 to the Consolidated Financial Statements. State income taxes decreased due to the book recognition of tax benefits of state tax net operating loss carryforwards.

Deferred income taxes increased during 1990, when compared to 1989, due primarily to the utilization of tax net operating loss carryforwards, offset in part by a reduction in the River Bend costs deferred for financial reporting purposes.

Non-Operating Items

Southern Company Settlement and Related Income Taxes. See Note 2 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 1991, when compared to 1990, due to franchise tax refunds the Company was allowed to retain as part of the rate case settlement in Texas, as discussed in Note 3 to the Consolidated Financial Statements.

Other — net increased during 1990, when compared to 1989, due to decreased income taxes on other income.

Application of SFAS No. 90 — Accounting for Abandonments and Disallowances of Plant Costs. See Note 3 to the Consolidated Financial Statements for the effect of the application of SFAS No. 90 to the Company's previously canceled River Bend Unit 2.

Interest Charges. 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 the Southern Company issued as part of the litigation settlement. This decrease was offset in part due to interest expense on the notes payable to the Southern Company recorded subsequent to the issuance of the notes on November 7, 1991. The Company will record interest expense on the discounted present value of the notes until 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 Company settlement, recorded prior to the consummation of the settlement.

Interest charges on long-term debt decreased during 1990, due to the retirement of $219,454,000 of debt that matured during 1990. Interest charges on short-term debt and other increased during 1990, due to interest expenses associated with the Southern Company settlement.

Extraordinary Item — Discontinuation of Regulatory Accounting Principles (Net of Income Taxes). See Note 3 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. In addition, see Note 3 to the Consolidated Financial Statements for a description of the write-offs in 1989 resulting from the application of SFAS No. 101 to the Company's wholesale jurisdiction during the third quarter of 1989 and to the steam department in the fourth quarter of 1989.

New Accounting Standards

The Financial Accounting Standards Board (FASB) has issued SFAS No. 109, Accounting for Income Taxes, which may affect the Company's results of operations and financial position when adopted. See Note 4 to the Consolidated Financial Statements for information regarding SFAS No. 109.

The FASB has issued SFAS No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions, that will significantly change the accounting for such benefits. The Company estimates that if it had applied the provisions of SFAS No. 106 in 1991, the Company would have recorded approximately $30,000,000 of expense related to postretirement benefits. The Company estimates that it would have an accumulated postretirement benefit obligation of $175,000,000 as of December 31, 1991. Annual expense for postretirement benefits under the provisions of SFAS No. 106 is estimated to range between $32,000,000 and $55,000,000 over the next 10 years. 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. See Note 5 to the Consolidated Financial Statements for the postretirement benefit costs recorded during 1991, 1990, and 1989. The Company will be required to apply SFAS No. 106 beginning in 1993.

Financial Information

Consolidated Statement of Income (Loss)

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

	1991	1990	1989
Operating Revenue			
Electric	**$1,623,959**	$1,596,635	$1,501,874
Steam	**46,418**	61,052	69,200
Gas	**31,858**	32,998	36,332
	1,702,235	1,690,685	1,607,406
Operating Expenses and Taxes			
Fuel	**446,543**	457,503	412,591
Purchased power	**161,374**	197,764	225,781
Other operations	**267,592**	256,951	274,150
Maintenance	**142,098**	131,775	120,570
Depreciation and amortization	**187,936**	186,451	187,985
Deferred River Bend expenses	—	—	16,739
Deferred revenue requirement — River Bend phase-in plan	**5,575**	(41,515)	(114,722)
Amortization of deferred River Bend costs	**32,661**	21,631	31,086
Income Taxes			
Federal	**39,140**	46,640	24,987
State	**(18,066)**	11,323	8,778
Other taxes	**88,402**	88,929	91,641
	1,356,255	1,357,452	1,279,586
Operating Income	**345,980**	333,233	327,820
Other Income and Deductions			
Allowance for equity funds used during construction	**608**	640	875
Southern Company settlement	—	(205,015)	—
Southern Company settlement related income taxes	—	80,834	—
Abandonment of subsidiary lignite leases	—	—	(29,183)
Other — net	**35,829**	21,513	15,826
Income Before Interest Charges and Application of SFAS No. 90	**382,417**	231,205	325,338
Application of SFAS No. 90 — Accounting for Abandonments and Disallowances of Plant Costs	—	—	(23,853)
Related Income Taxes	—	—	8,965
	—	—	(14,888)
Interest Charges			
Long-term debt	**234,418**	259,186	289,058
Short-term debt and other	**26,038**	16,811	10,403
Allowance for borrowed funds used during construction	**(488)**	(510)	(2,262)
	259,968	275,487	297,199
Income (Loss) Before Extraordinary Item	**122,449**	(44,282)	13,251
Extraordinary Item — Discontinuation of Regulatory Accounting Principles (net of income taxes) (Note 3)	**(20,166)**	—	(58,824)
Net Income (Loss)	**102,283**	(44,282)	(45,573)
Dividends on Preferred and Preference Stock	**63,070**	62,742	62,839
Income (Loss) Applicable to Common Stock	**$ 39,213**	$ (107,024)	$ (108,412)
Average Shares of Common Stock Outstanding	**114,055**	108,055	108,055
Earnings (loss) per average share of common stock outstanding before extraordinary item	**$ .52**	$ (.99)	$ (.46)
Earnings (loss) per average share of common stock outstanding	**$ .34**	$ (.99)	$ (1.00)
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)

	1991	1990	1989
Operating Activities			
Net income (loss)	**$ 102,283**	$ (44,282)	$ (45,573)
Adjustments to reconcile net income (loss) to net cash from operating activities:			
Provision for rate refund — Louisiana	**24,143**	—	—
Deferred fuel and purchased power expense — net	**23,374**	1,899	(18,103)
Amortization of nuclear fuel	**42,172**	35,454	30,102
Depreciation and amortization	**187,521**	188,885	191,254
Deferred River Bend expenses, revenue requirement, and carrying charges	**5,575**	(41,315)	(97,464)
Amortization of accumulated deferred River Bend costs	**32,661**	21,631	31,086
Deferred income taxes — net	**36,540**	(16,169)	49,993
Investment tax credits — net	**(4,308)**	(4,286)	(4,42[illegible])
Allowance for funds used during construction	**(1,096)**	(1,150)	(3,137)
Southern Company settlement	**12,565**	213,885	—
Abandonment of subsidiary lignite leases	**—**	—	19,183
Application of SFAS No. 90 — accounting for abandonments and disallowances of plant costs (net of income taxes)	**—**	—	14,888
Extraordinary item — discontinuation of regulatory accounting principles (net of income taxes)	**20,166**	—	58,824
Disputed amount	**—**	—	(7,795)
Other	**(19,022)**	16,439	26,995
Changes in:			
Receivables	**(12,503)**	(1,897)	(16,990)
Fuel inventories	**10,422**	(3,155)	3,113
Materials and supplies	**(146)**	(919)	(1,027)
Prepayments and other current assets	**(9,825)**	2,173	2,072
Accounts payable — trade	**(6,912)**	9,959	(7,828)
Customer deposits	**1,258**	1,031	1,221
Taxes accrued	**753**	(1,601)	(12,419)
Interest accrued	**3,211**	(10,927)	(1,322)
Other current liabilities	**21,315**	(1,667)	7,422
Net cash flow provided by operating activities	**470,147**	363,788	220,071
Financing Activities			
Increase (decrease) in deferred River Bend construction commitments	**(321)**	[illegible],363	2,826
Increase in long-term debt	**200,000**	–	679
Payment of deferred River Bend construction and continuing service commitments	**(12,108)**	[illegible]0)	(31,517)
Payments of lease obligations	**(36,890)**	(4[illegible]0)	(27,552)
Retirement of long-term debt	**(320,653)**	(202,654)	(111,653)
Payment of preferred dividends	**(127,398)**	—	—
Net cash flow used by financing activities	**(297,370)**	(262,201)	(167,217)
Investing Activities			
Construction expenditures	**(87,470)**	(73,020)	(54,679)
Nuclear fuel expenditures	**—**	—	(20,209)
Sale of nuclear fuel — River Bend fuel lease	**—**	—	114,931
Allowance for funds used during construction	**1,096**	1,150	3,137
Deposit to escrow account	**(2,975)**	(11,463)	—
Other property and investments	**13,045**	(19,184)	(909)
Net cash flow provided by (used by) investing activities	**(76,304)**	(102,517)	42,271
Net change in cash and cash equivalents	**96,473**	(930)	95,125
Cash and cash equivalents at January 1	**196,588**	197,518	102,393
Cash and cash equivalents at December 31	**$ 293,061**	$ 196,588	$ 197,518
Supplemental Cash Flow Disclosure			
Cash paid during the period for:			
Interest	**$ 227,306**	$ 267,529	$ 286,211
Income taxes	**5,700**	6,359	812
Increase in nuclear fuel lease obligations	**13,958**	24,623	3,521

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

Financial Information

Consolidated Balance Sheet

December 31
(in thousands)

	1991	1990
Assets		
Utility and Other Plant, at original cost		
Plant in service	$6,873,767	$6,741,601
Less: Accumulated provision for depreciation	2,024,351	1,847,882
	4,849,416	4,893,719
Construction work in progress	36,538	24,576
Nuclear fuel, net of accumulated amortization	107,071	135,285
	4,993,025	5,053,580
Other Property and Investments	50,200	61,301
Current Assets		
Cash and cash equivalents	293,061	196,588
Receivables		
Customers	121,897	115,725
Other	25,095	18,764
Fuel inventories	17,007	27,429
Materials and supplies	8,097	7,951
Prepayments and other	45,283	35,458
	510,440	401,915
Deferred Charges and Other Assets		
Accumulated deferred income taxes	190,438	169,355
Deferred River Bend costs	891,568	954,163
Other	275,821	222,955
	1,357,827	1,346,473
	$6,911,492	$6,863,269
Capitalization and Liabilities		
Capitalization (See Statement of Capitalization)		
Common shareholders' equity	$2,021,673	$1,928,022
Preference stock	100,000	100,000
Preferred stock		
Not subject to mandatory redemption	136,444	136,444
Subject to mandatory redemption	362,580	438,631
Long-term debt	2,293,982	2,074,112
	4,914,679	4,677,209
Current Liabilities		
Long-term debt due within one year	94,003	252,[illegible]83
Preferred stock and long-term debt sinking fund requirements	52,205	76,[illegible]63
Deferred River Bend construction commitments	—	12,[illegible]29
Accounts payable — trade	107,684	109,596
Customer deposits	20,156	18,898
Taxes accrued	21,726	20,973
Interest accrued	77,289	74,078
Capital leases — current	21,328	38,952
Other	75,718	48,454
	465,109	652,426
Deferred Credits and Other Liabilities		
Investment tax credits	96,889	101,197
Accumulated deferred income taxes	807,678	667,518
Capital leases — non-current	116,805	122,113
Deferred River Bend financing costs	155,482	179,841
Southern Company settlement	47,400	235,283
Other	307,450	227,682
	1,531,704	1,533,634
Commitments and Contingencies (Note 2)		
	$6,911,492	$6,863,269

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)

	Preferred Stock Subject to Mandatory Redemption	Common Stock	Premium (Less Expense)	Other Paid in Capital	Retained Earnings
Balance: January 1, 1989	$387,189	$1,195,148	$ (3,936)	$26,163	$870,680
Net loss — 1989					(45,573)
Preferred stock sinking fund requirements	(7,680)				
Dividends in arrears on preferred stock subject to mandatory redemption	35,142				(35,142)
Capital stock expense				10	
Balance: December 31, 1989	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	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	$362,580	$1,200,923	$ (4,155)	$78,148	$746,757

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

Consolidated Statement of Capitalization

December 31
(in thousands)

	1991	1990
Common Shareholders' Equity		
Common stock		
Authorized 200,000,000 shares without par value		
Outstanding 114,055,065 and 108,055,065 shares	**$1,200,923**	$1,195,148
Premium and expense on capital stock	**(4,155)**	(3,936)
Other paid-in capital	**78,148**	26,173
Retained earnings	**746,757**	710,637
	2,021,673	1,928,022

Preference Stock
Authorized 20,000,000 shares without par value, cumulative
Outstanding 4,000,000 shares

Dividend Series	Cumulative Per Share Dividends in Arrears	Shares Outstanding	Redemption Price as of December 31, 1991	1991	1990
$ 4.40	$22.18	2,000,000	$ 30.45	**50,000**	50,000
3.85	19.41	2,000,000	30.15	**50,000**	50,000
				100,000	100,000

Preferred Stock
Authorized 6,000,000 shares, $100 par value, cumulative
Outstanding 4,617,568 shares

Dividend Series	Cumulative Per Share Dividends in Arrears	Shares Outstanding	Redemption Price as of December 31, 1991	1991	1990
Not subject to mandatory redemption					
$ 4.40	$10.08	51,173	$108.00	**5,117**	5,117
4.50	10.31	5,830	105.00	**583**	583
4.40-1949	10.08	1,655	103.00	**166**	166
4.20	9.63	9,745	102.818	**975**	975
4.44	10.18	14,804	103.75	**1,480**	1,480
5.00	11.46	10,993	104.25	**1,099**	1,099
5.08	11.64	26,845	104.63	**2,685**	2,685
4.52	10.36	10,564	103.57	**1,056**	1,056
6.08	13.93	32,829	103.34	**3,283**	3,283
7.56	17.33	350,000	101.80	**35,000**	35,000
8.52	19.53	500,000	104.43	**50,000**	50,000
9.96	22.83	350,000	104.64	**35,000**	35,000
				136,444	136,444
Subject to mandatory redemption					
$ 8.80	20.17	301,029	103.00	**30,103**	30,103
9.75	22.34	29,636	103.00	**2,963**	2,963
8.64	19.80	302,465	103.00	**30,247**	30,247
11.48	26.31	480,000	103.00	**48,000**	48,000
13.64	31.26	40,000	103.00	**4,000**	4,000
12.92	29.61	600,000	105.00	**60,000**	60,000
11.50	26.35	750,000	105.00	**75,000**	75,000
Adjustable Rate	22.05	300,000	103.00	**30,000**	30,000
Adjustable Rate	21.63	450,000	103.00	**45,000**	45,000
Preferred dividends in arrears				**80,477**	141,711
				405,790	467,024
Preferred stock sinking fund requirements				**(43,210)**	(28,393)
				362,580	438,631

(Statement continued on following page.)

	1991	1990
Long-Term Debt		
First mortgage bonds		
Maturing 1992 through 1996 —		
17½% due January 13, 1992	$ —	$ 60,000
4⅝% due May 1, 1992	—	17,000
16.8% due September 23, 1993	17,150	25,720
13¾% due March 1, 1994	100,000	100,000
5% due January 1, 1996	20,000	20,000
Maturing 1997 through 2001 — 5⅝% through 8½%	245,000	245,000
Maturing 2002 through 2006 — 8½% through 10.15%	210,000	210,000
Maturing 2007 through 2011 — 8⅝% through 12.3%	285,000	285,000
Maturing 2012 through 2016 — 11⅝% through 15%	600,000	600,000
First mortgage bond sinking fund requirement	(8,570)	(48,570)
	1,468,580	1,514,150
Pollution control and industrial development bonds		
7% due 2006	25,000	25,000
5.9% due 2007	23,000	23,000
10⅜% due 2012	48,285	48,285
9½% due 2013	17,450	17,450
10⅛% due 2014	50,000	50,000
12% due 2014	52,000	52,000
Variable rate due 2014	—	94,000
7.7% due 2014	94,000	—
Variable rate due 2015	109,000	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)	—
Euro-debentures — 13% due March 4, 1992	—	75,000
Convertible debentures — 7¼% due September 1, 1992	—	2,003
Debentures — due 1998 — 9.72%	200,000	—
Notes payable — Southern Company due January 1, 1993	142,697	—
Other long-term debt	2,038	2,038
	2,296,625	2,076,926
Unamortized premium and discount on debt — net	(2,643)	(2,814)
	2,293,982	2,074,112
	$4,914,679	$4,677,209

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:

	1991	1990	1989
Electric	2.68%	2.70%	2.68%
Steam	4.22	4.23	4.16
Gas	3.53	3.53	3.53
Total Company	2.70	2.72	2.70

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, 1989 - March 31, 1989	12.25%
April 1, 1989 - March 31, 1990	11.75
April 1, 1990 - March 31, 1991	11.50
April 1, 1991 - December 31, 1991	11.75

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. Reconciliable 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, valued at weighted average cost, and coal, valued at last-in, first-out (LIFO) 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.

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), GSG&T, Inc. (GSG&T), and Gulf States Overseas Finance N.V. 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.

Reclassification of Financial Statements. Prior year financial statements have been reclassified in order to be consistent with current year presentation with no effect on net income (loss) or common shareholders' equity.

2. 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. In 1991, the Company's financial position 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 1992, 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 have 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 settlement agreement previously 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, 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; and

(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.

In addition, the Settlement Agreement provides that on January 1, 1993, the Company will pay Southern for each of the 6,000,000 shares of common stock, the amount by which (if any) $18.25 exceeds the highest average of the highest prices at which the Company's common stock trades for five consecutive days during the period November 7, 1991, (the date the shares were delivered to Southern) and January 1, 1993. Since the consummation of the settlement on November 7, 1991, the Company's common stock had a five day average high price of $10.35 per share as of December 31, 1991. However, if the Company does not have "adequate cash" on January 1, 1993, all unpaid amounts owed under the stock agreement discussed above and under the promissory notes would begin to accrue interest at the prime rate plus 1 percent and would be payable on the earlier of the January 1st as of which the Company has "adequate cash" or January 1, 1999. Pursuant to the Settlement Agreement, the Company would be deemed to have "adequate cash" at the time it begins to pay cash dividends on its outstanding common stock or to the extent its projected available cash balance each year exceeds $35,000,000.

The Company will record interest on the discounted present value of the notes payable until January 1, 1993.

The Company's obligations under the settlement are secured by a first mortgage lien on the Lewis Creek generating station, a 520 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.

Financial Information

On [illegible] filed a civil action against the Company in the U. S. District Court for the [illegible] District of Louisiana. CEPCO stated in its [illegible] the suit is to [illegible] and/or dissolve the [illegible] Participation and Operating Agreement [illegible] on August 28, 1979, (Operating Agreement) [illegible] to River Bend because of [illegible] 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.

The Company believes the suit is without merit and is contesting it 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 refinanced CEPCO's outstanding debt. Additionally, one of CEPCO's member cooperatives has filed bankruptcy. CEPCO's weak financial condition or its bankruptcy could have significant adverse effects on the Company, including, but not limited to, possible Nuclear Regulatory Commission (NRC) action with respect to the operation of River Bend and a need to bear additional costs associated with the co-owned facilities. During 1992, and for the next several years, it is expected that CEPCO's share of River Bend-related costs will be in the range of $65,000,000 to $75,000,000 per year. If the Company were required to fund CEPCO's share of costs, there can be no assurance that the Company's resources would be adequate.

The Company and CEPCO are parties to FERC proceedings regarding certain long-standing 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, which is subject to a final FERC order. The Company claims CEPCO has underpaid transmission charges, which as of December 31, 1991, amount to $104,855,000. 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. No assurance can be given as to the timing or outcome of the final FERC order.

The Company has been informed by CEPCO that it will not participate in funding its share of the costs associated with certain repairs and improvements to a service water system and repairs to a feedwater nozzle at River Bend which are scheduled for the refueling outage which will begin in the spring of 1992. CEPCO has withheld funds called for by the Company for this purpose. The Company presently intends to make such repairs and, without waiving any rights against CEPCO, will pay costs incurred therefor if not funded by CEPCO. Total costs expected to be incurred in connection with the repairs and improvements referred to above are approximately $60,000,000. 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 injunctive relief against the Company. The Company is contesting such suit and is reviewing its available legal remedies.

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. There is also no assurance that the Company will be able to maintain insurance coverages at their present levels. Under those circumstances, such losses or liabilities would have a very substantial adverse effect on the financial condition of the Company.

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. 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 $765,000,000 of excess insurance for River Bend from the private insurance market. Additionally, the Company has acquired $1,250,000,000 of excess property insurance coverage on River Bend through participation in the Nuclear Electric Insurance Limited (NEIL) II program. Under NEIL II, the Company is subject to a maximum assessment of approximately $6,519,000 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 the Company's 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 mortgagees, 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. In 1991 dollars, the Company's share of decommissioning costs, based on currently approved funding by the respective regulatory commissions, is estimated to be $198,000,000. A recently completed engineering study, which has yet to be approved as a basis for funding, indicates that the Company's share in 1991 dollars may increase to approximately $281,000,000, which at the end of the life of the unit may be approximately $1.8 billion. To provide for future decommissioning costs, the amounts collected through rates from customers, plus interest, are placed in a master trust fund to provide amounts needed in the future. The Company has elected the provisions of section 468A of the Internal Revenue Code to qualify for an annual tax deduction for payments made to the nuclear decommissioning fund. At December 31, 1991, the balance in the decommissioning trust fund was $7,368,000. There can be no assurance that the amount being provided for will be adequate.

Dividend Matters

Preferred Stock. In February 1987, the Board of Directors omitted dividends on the Company's preferred stock to have been payable in March 1987. The Company continued to omit preferred dividends through June 1991. Dividends on preferred stock are cumulative. Since the Company failed to pay preferred dividends, the holders of preferred stock became eligible, as of March 15, 1988, to elect a majority of the Board of Directors, and have done so since the annual meeting in 1988. On September 15, 1991, the Company paid $46,336,000 of preferred dividends, equal to four quarters in arrearages. On December 15, 1991, the Company paid $81,062,000 of preferred dividends, equal to seven quarters in arrearages. The Company is also in arrears on preferred stock 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 has continued to omit preference dividends through December 1991. Dividends on preference stock are cumulative. Since the Company failed to pay preference dividends, the holders of preference stock became eligible, as of September 15, 1988, to elect two directors to the Board, and have done so since the annual meeting in 1989. The Company may not pay any dividend or distribution on any of its preference stock, or acquire preference stock, unless all accrued dividends and sinking fund obligations have been paid on preferred stock.

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. The Company may not pay any dividend or make any distribution on any of its common stock or purchase or otherwise acquire common stock unless all cumulative dividends and sinking fund obligations have been paid on all preferred and preference stock.

DIVIDEND PAYMENTS AND ARREARAGES. Detailed below are the balances of cumulative dividends and sinking funds in arrears:

	Preferred Stock Dividends	Preference Stock Dividends	Total Dividends	Preferred Stock Sinking Fund Requirement	Total
			(In thousands)		
Amounts in arrears at December 15, 1990	$185,039	$66,000	$251,039	$17,327	$268,366
1991 requirement	46,582	16,500	63,082	11,066	74,148
September 1991 dividend payment	(46,336)	—	(46,336)	—	(46,336)
December 1991 dividend payment	(81,062)	—	(81,062)	—	(81,062)
Amounts in arrears at December 15, 1991	$104,223	$82,500	$186,723	$28,393	$215,116

Payment of current dividends on all stock is at the discretion of the Board of Directors and depends upon its continuing evaluation of the financial condition of the Company. However, it is an objective of the Company to pay all dividends in arrears on preferred and preference stock, all sinking fund obligations on preferred stock, and to resume payment of dividends on common stock as soon as the Board believes the Company is financially able to do so.

Under the terms of its short-term bank credit agreement discussed in Note 12, the Company is restricted from paying dividends, while the credit agreement is in effect, in excess of $150,000,000 in total on any of its classes of stock. In January 1992, the Company received a waiver under the short-term credit agreement to pay the remaining preferred stock dividend arrearages. The Company's ability to declare and pay dividends is also restricted by provisions of its Restated Articles of Incorporation, various indentures, and state and federal law. The Company's ability to pay dividends and arrearages 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. 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.

The Company has accrued dividends on and increased the balance of mandatory redeemable preferred stock with an offsetting decrease to retained earnings. However, since dividends on all series of the Company's preferred and preference stock, both mandatory and nonmandatory redeemable, are cumulative, income (loss) applicable to common stock and earnings (loss) per average share of common stock outstanding have been computed assuming that all such dividends through December 31, 1991, were accrued.

See Note 15 for information regarding the February 13, 1992 declaration by the Board of Directors of preferred stock dividend and sinking fund arrearages.

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. During 1991, the Company increased its reserve for cleanup of sites by $14,550,000. 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.

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.

3. Rates and Accounting

Rate Matters

Texas — Docket No. 7195. On May 16, 1988, the PUCT granted the Company a permanent rate increase 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 costs with no finding as to 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 Texas Supreme Court subsequently 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 future rate cases. 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 recent decision regarding El Paso Electric Company's 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.

As of December 31, 1991, on a Texas retail jurisdictional basis, the disallowed River Bend plant costs were approximately $19,000,000, and the River Bend plant costs held in abeyance totaled approximately $411,000,000, both net of accumulated depreciation and related taxes. The River Bend cost deferrals associated with the portion of the investment held in abeyance, which were also held in abeyance as of December 31, 1991, amounted to approximately $161,000,000, net of taxes. River Bend cost deferrals which were allowed in rate base in Texas were approximately $107,000,000, net of taxes, as of December 31, 1991. At December 31, 1991, the Company estimates it had collected approximately $85,000,000 of revenues as a result of the previously ordered rate treatment of these deferred costs and currently estimates that it collects revenues associated with such deferred costs of approximately $2,300,000 monthly, or $28,000,000 annually, from ratepayers in Texas. The reversal of the deferral offset contemplated by the court is not expected to have a material impact on the net amount of any potential write-off of deferrals.

Deferred costs associated with Big Cajun 2 Unit 3 totaled approximately $4,369,000 (net of taxes) as of December 31, 1991, of which approximately $1,880,000 (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 before the court. The Company's motion for retrial was denied, and on December 18, 1991, the Company filed an appeal of the October 1, 1991 district court order.

Pending resolution of various appellate proceedings, the Company has made no write-off for the previously disallowed portion of River Bend plant costs or the previously abeyed River Bend plant costs and deferred River Bend costs discussed above.

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 put in abeyance by the PUCT. 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 December 11, 1990, the Company implemented a base rate increase of $65,089,000 under bond, subject to refund.

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 base rate increase and retained approximately $16,800,000 in franchise tax refunds. The Company increased its annual fuel revenue by $17,500,000 under the fixed fuel factor, and is refunding to ratepayers over 12 months approximately $25,400,000 in existing fuel revenue overrecoveries. The Company also refunded approximately $7,562,000 of revenue (including interest), collected subject to refund as part of the approximate $65,089,000 base rate increase placed in effect on December 11, 1990 under bond. The Company also agreed not to file a new base rate request for two years, with certain exceptions. The order was appealed by certain parties, and there can be no assurance as to the timing or ultimate outcome of such appeals.

On December 13, 1991, the 53rd Judicial District Court of Travis County considered arguments on the appeals. Following argument, the District Court advised the parties that, if the decision of the Court of Appeals in Public Utility Commission of Texas v. GTE-SW, as it relates to the calculation of federal income taxes for regulatory purposes, is not reversed on rehearing (the case is now before the Court of Appeals on rehearing), the District Court intends to reverse the PUCT on that issue and remand the matter of the Company's rate order to the PUCT. However, if the GTE case is reversed, then the District Court intends to decide all of the issues in the appeal before it. If the Company's case (Docket No. 8702) is remanded to the PUCT, the PUCT could reduce the Company's rates in an amount up to $1,700,000 per month from the time of the original PUCT decision.

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 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, 1991, the Company had recorded, with no effect on net income, $52,048,000 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.

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, 1991 was $23,588,000. Currently, no hearings have been set in this proceeding.

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. Phase-in Plan Fourth Step. On February 26, 1991, the LPSC granted the Company a $16,800,000 base rate increase as the fourth and final step of the February 18, 1988 court-ordered phase-in plan, effective March 1, 1991.

Louisiana Supreme Court Ruling. On April 5, 1991, the Louisiana Supreme Court affirmed the district court order of October 11, 1989, which upheld the LPSC finding that the Company's 1979 decision to restart River Bend was imprudent and which disallowed $1.4 billion of the River Bend plant investment. The Louisiana Supreme Court reversed and set aside the district court's order

which implemented the deregulated asset plan for the $1.4 billion of River Bend plant investment.

The Louisiana Supreme Court also reversed and set aside the 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. This resulted in a net of tax charge of $13,200,000. 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 ($13,200,000 net of tax) 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 ($9,864,000 net of tax) in the fourth quarter of 1991. The $24,143,000 principal will be refunded in two steps, one-half in July 1992 and one-half in July 1993. Interest was recorded through credits to the deferred River Bend revenue requirement associated with the phase-in plan.

On December 9, 1991, the United States Supreme Court refused to hear the Company's appeal of the Louisiana Supreme Court's decision.

Louisiana Deregulated Asset Plan. Hearings on the deregulated asset plan were held before the LPSC in October and December 1991.

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 Statement of Financial Accounting Standards (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), which was recorded as an extraordinary item. 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. After consideration of such plan, the LPSC will determine whether any further action will be taken based on the audit.

Accounting Developments

SFAS No. 90. In December 1986, the Financial Accounting Standards Board (FASB) issued SFAS No. 90, Regulated Enterprises — Accounting for Abandonments and Disallowances of Plant Costs, which amends certain accounting standards for rate regulated enterprises. SFAS No. 90 specifies the accounting for the effect of disallowances of costs of newly completed plants and plant abandonments. Additionally, it required the Company to reduce its investment in the abandoned River Bend Unit 2 to an amount equal to the present value of the probable future revenues expected to be provided over the amortization period authorized by regulators. In subsequent periods, the Company is recognizing interest income to the extent of the difference between amortization allowed for regulatory purposes and the reduced amortization recorded for financial reporting purposes.

During 1989, the Company reduced its investment in River Bend Unit 2 by $23,853,000 before related income tax benefits of $8,965,000 for the Louisiana retail jurisdiction and steam department. This write-down resulted from the February 28, 1989 LPSC rate order which allowed the Company to recover its investment in River Bend Unit 2 but did not allow a return on the investment. Accordingly, this write-down was computed in accordance with SFAS No. 90 and was not recorded as a cumulative effect of an accounting change.

SFAS No. 101. In December 1988, the 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.

Steam Department. The Company has, for a number of years, produced steam at its Louisiana Station No. 1 and sold such steam, along with the cogenerated electricity, to industrial customers located adjacent to Louisiana Station. Electric power requirements of these customers in excess of the by-product electricity have been met by

the Company with power from the Company's system power grid. In the past, contractual arrangements with the steam customers called for that power provided from the grid to be billed at rates set in rate proceedings by the LPSC. As a result of this arrangement, the Company had previously accounted for the steam department in accordance with the provisions of SFAS No. 71.

During the fourth quarter of 1989, the Company discontinued regulatory accounting principles for the steam department and wrote-off the deferred revenue requirement and accounting order deferrals and made other adjustments. The write-off was recorded as an extraordinary item and amounted to $34,431,000 before the related income tax benefits of $12,527,000.

WHOLESALE JURISDICTION. During June through August 1989, the Company reached agreements with a majority of its wholesale customers which, among other things, lowered the contracted amount of power and the rates for such power. Upon approval by the FERC of these agreements in the third quarter of 1989, the Company discontinued regulatory accounting principles for the wholesale jurisdiction, wrote-off the deferred revenue requirement previously recorded by the Company with respect to the phase-in plan for its wholesale customers, and made other adjustments. The write-off was recorded as an extraordinary item and amounted to $65,502,000 before the related income tax benefits of $28,582,000.

LOUISIANA DEREGULATED PORTION OF RIVER BEND. See "Rate Matters — Louisiana Deregulated Asset Plan" above.

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.

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 recent 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, 1990	Changes for the Year Ended December 31, 1991			Balance at December 31, 1991
		Additions	Refund	Amortization	
	(in thousands)				
DEFERRED REVENUE REQUIREMENTS — PHASE-IN PLAN					
Louisiana retail jurisdiction	$319,455	$5,227	$(10,802)	$ (8,723)	$305,157
ACCOUNTING ORDER DEFERRALS					
Texas retail jurisdiction					
Deferred River Bend costs	368,953	—	--	—	368,953
Amortization of deferred River Bend costs	(11,130)	—	—	(9,332)	(20,462)
Louisiana retail jurisdiction					
Deferred River Bend costs	400,375	—	—	—	400,375
Amortization of deferred River Bend costs	(123,490)	—	—	(38,965)	(162,455)
	634,708	—	—	(48,297)	586,411
DEFERRED RIVER BEND COSTS	$954,163	$5,227	$(10,802)	$(57,020)	$891,568

The deferred income taxes related to the amounts detailed above at December 31, 1991 and 1990 of $232,038,000 and $247,565,000, 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, 1990	Changes for the Year Ended December 31, 1991 Amortization	Balance at December 31, 1991
		(In thousands)	
DEFERRED RIVER BEND FINANCING COSTS			
Texas retail jurisdiction	$107,359	$(14,203)	$ 93,156
Louisiana retail jurisdiction	72,482	(10,156)	62,326
DEFERRED RIVER BEND FINANCING COSTS	$179,841	$(24,359)	$155,482

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. In July 1988, the Company began amortizing over a 40-year period approximately $182,000,000 of deferred costs and accrued carrying charges associated with the portion of River Bend ruled prudent by the PUCT in accordance with the May 16, 1988 rate order. The amortization period was subsequently reduced to a 20-year period in accordance with the March 22, 1991 Texas rate order.

4. 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:

	1991	1990	1989
		(In thousands except percents)	
Net income (loss) before federal income taxes	$160,685	$(60,781)	$(51,14_)
Statutory tax rate	34%	34%	34%
Federal income taxes (benefits) at statutory tax rate	54,633	(20,666)	(17,389)
Additions (reductions) in federal income taxes resulting from:			
Exclusion of River Bend carrying charges from taxable income	8,663	8,159	8,653
Items capitalized for book purposes but expensed for tax purposes	(10,319)	(9,235)	(7,484)
Non-deferred depreciation differences	3,412	11,058	12,009
Adjustment for prior years taxes and other regulatory adjustments	1,250	(157)	(1,235)
Non-deferred differences of nonutility subsidiaries	573	(900)	6,026
Deferral of nuclear fuel savings	(1,920)	(1,573)	(_,625)
Amortization of investment tax credit	(4,308)	(4,286)	(4,424)
Effect of SFAS No. 101	6,500	(443)	639
Other items	(82)	1,564	(741)
Total federal income taxes (benefits)	$ 58,402	$(16,499)	$ (5,571)
Effective federal income tax rate	36.3%	27.1%	10.9%

The components of federal income taxes are as follows:

	1991	1990	1989
		(In thousands)	
Charged to operating expenses:			
Current federal income tax provision (benefits)	$ 3,558	$ (5,084)	$ —
Deferred federal income taxes — net			
Tax depreciation	51,576	49,773	55,361
Capitalized construction costs	(666)	(266)	(113)
Nuclear unit cancellation costs net of amortization	(2,352)	(2,385)	(2,414)
Fuel and purchased power costs deferred (accrued)	(4,012)	(675)	6,974
Expenses deferred for tax purposes	(4,525)	(1,240)	(714)
Tax net operating loss carryforward	59,473	17,981	(59,605)
River Bend operating expenses deferred for financial reporting, expensed for tax purposes	(12,780)	7,111	25,705
Unbilled revenues	701	(6,632)	(5,420)
State tax refund deferred for financial reporting	—	(696)	(5,741)
Income deferred for book purposes	(12,152)	—	—
Provision for rate refund — Louisiana	(6,209)	—	—
Alternative minimum tax credit	(5,595)	(3,632)	—
Other	(1,569)	(3,333)	(4,622)
Total deferred federal income taxes — net	39,890	56,010	29,411
Investment tax credits — net	(4,308)	(4,286)	(4,424)
Total federal income taxes charged to operating expenses	39,140	46,640	24,987
Southern Company settlement	—	(69,705)	—
Charged to other income — net	12,760	6,566	11,620
Application of SFAS No. 90 — Accounting for abandonments and disallowances of plant costs	—	—	(7,670)
Charged to extraordinary item	6,502	—	(34,508)
Total federal income taxes (benefits)	$58,402	$(16,499)	$ (5,571)

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 $75,000,000 at December 31, 1991. 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, 1991, for tax purposes, the Company had federal tax loss carryforwards of approximately $810,000,000 and investment tax credit carryforwards of approximately $183,000,000. These will be used to reduce income tax payments in future years and, if not used, will expire through the year 2004.

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 previously flowed through tax benefits and the equity component of AFUDC. Adoption of SFAS No. 109 is required in 1993, and when adopted is expected to have a significant impact on the Company's balance of deferred income taxes, plant in service and regulatory assets. The impact on the Company's Consolidated Statement of Income (Loss) for future years may be significant, but will ultimately depend on the regulatory treatment of these items.

5. 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, 1991, 1990, and 1989 was $5,110,000, $3,025,000, and $2,357,000, respectively. Of such amounts, $4,552,000, $2,693,000, and $2,107,000, 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 1991, 1990, and 1989, are summarized as follows:

	1991	1990	1989
	(in thousands)		
Service cost	$10,306	$ 9,660	$ 7,835
Interest cost on projected benefit obligation	15,355	14,224	12,876
Actual return on plan assets	(56,898)	6,875	(46,308)
Unrecognized net gain (loss)	37,349	(25,520)	29,991
Amortization of net gain	—	(1,212)	(745)
Amortization of prior service cost	1,385	1,385	1,095
Amortization of net transition asset	(2,387)	(2,387)	(2,387)
Net pension cost	$ 5,110	$ 3,025	$ 2,357

The obligations for plan benefits and the amount recognized in the Company's Consolidated Balance Sheet at December 31, 1991, 1990, and 1989, are reconciled as follows:

	1991	1990	1989
	(in thousands)		
Actuarial Present Value of Benefit Obligations:			
Accumulated benefit obligation, including vested benefits of $186,161, $170,721, and $125,958, respectively	$ 192,092	$ 174,789	$ 146,625
Projected benefit obligation	$ (248,817)	$ (228,528)	$ (190,770)
Plan assets, at fair market value	290,211	235,871	253,810
Plan assets in excess of projected benefit obligation	41,394	7,343	63,040
Unrecognized net gain	(48,930)	(15,417)	(61,362)
Unrecognized net assets being amortized over 15 years	(21,487)	(23,374)	(26,262)
Unrecognized prior service cost	26,873	25,777	23,378
Accrued pension liability	$ (2,150)	$ (4,231)	$ (1,206)

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:

	1991	1990	1989
Discount rate	7.25%	7.25%	7.75%
Expected long-term rate of return on assets	8.50	7.50	7.50
Average future salary level increase	6.10	6.10	6.10

At December 31, 1991, 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 $1,253,000 of expense related to the 1986 early retirement plan for the year ended December 31, 1991, 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 $5,514,000, $4,722,000, and $4,051,000, for the years 1991, 1990, and 1989, 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 if it had applied the provisions of SFAS No. 106 in 1991, the Company would have recorded approximately $30,000,000 of expense related to postretirement benefits. The Company estimates that it would have an accumulated postretirement

benefit obligation of $175,000,000 as of December 31, 1991. Annual expense for post-retirement benefits under the provisions of SFAS No. 106 is estimated to range between $32,000,000 and $55,000,000 over the next 10 years. 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.

6. Abandonment of Subsidiary Lignite Leases

Varibus acquired the rights to lignite reserves in the mid 1970's as fuel reserves for the Company's proposed lignite generating units. Upon deferral of construction of the proposed lignite units, Varibus retained its investment in the lignite reserves in order to market them. In October 1989, Varibus determined all efforts to market the lignite reserves had failed and, therefore, abandoned the leases and wrote-off its $19,183,000 investment in lignite leases.

7. Jointly-Owned Facilities

As of December 31, 1991, 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	$3,075,945	$405,734	$219,503
Accumulated depreciation	421,942	117,811	55,594
Total plant capability	936 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 13 for information relating to a buyback agreement between the Company and a participant in Nelson Unit 6.

8. Leases

The Company has existing agreements for the leasing of certain vehicles, coal rail cars and other equipment, buildings, and nuclear fuel. Lease charges were $73,554,000, $65,984,000, and $60,819,000 for the years ended December 31, 1991, 1990, and 1989, respectively. Of such amounts, $72,976,000, $65,114,000, and $60,256,000, respectively, were charged to income.

Future minimum lease payments under non-cancellable capital and operating leases for each of the next five years and in the aggregate at December 31, 1991, are estimated to be (in thousands):

1992	$ 47,137
1993	68,267
1994	55,892
1995	40,682
1996	10,785
Remaining years	139,991
	$362,754

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, preference, 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). (See Note 2 for information on the payment of preferred stock dividends during 1991.) The Company also 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, 1991, 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.

The Restated Articles of Incorporation (Articles) provide that, at the Company's option, all or part of its preferred and preference stock may be redeemed at stated prices.

At December 31, 1991, 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 (4,617,568 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, 1991, and ex. ng circumstances, the Company believes it is unable to issue any additional preferred stock.

Certain limitations on the payment of cash dividends on common stock are contained in the Articles, indentures, loan agreements, and applicable state and federal law. Under existing limitations, as discussed in Notes 2 and 12, the Company may not pay dividends on such stock. If such restrictions did not exist, the most restrictive limitation at December 31, 1991, 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, 1991, amounted to $621,000,000. Preferred and preference dividend requirements, as well as preferred stock sinking fund requirements, have priority over the payment of cash dividends on common stock.

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 preference stock.

10. Preferred Stock Subject to Mandatory Redemption

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, plus any dividends in arrears on such stock (see Note 2).

As of December 31, 1991, the Company has failed to satisfy $28,393,000 of preferred stock sinking fund requirements.

During 1986, the Company purchased in the open market, shares of the applicable series of preferred stock in excess of the amount needed to satisfy the 1986 sinking fund requirement. At December 31, 1991, assuming that the additional shares purchased during 1986 are used to satisfy future sinking fund requirements, minimum redemption requirements amount to $14,816,700 for each of the years from 1992 through 1996, exclusive of the $28,393,000 unsatisfied provision discussed above. (See Notes 2, 12 and 15 for limitations on payment of dividends on and purchases of preferred stock, and the February 13, 1992 declaration by the Board of Directors of preferred stock dividend and sinking fund arrearages).

11. 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 plans 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 (in thousands):

	Sinking Fund Requirements Satisfied by		Long-Term Debt Maturities	
	Cash	Property Additions	First Mortgage Bonds and Debentures	Notes Payable—Southern Company
1992	$8,995	$17,520	$ 94,003	$ —
1993	425	17,520	8,580	160,000
1994	425	16,320	100,000	—
1995	425	16,320	—	—
1996	425	16,080	20,000	—

During 1991, the Company completed the sale of $200,000,000 principal amount of 9.72% debentures and primarily used the proceeds to retire the remaining amounts outstanding under a revolving credit agreement.

The Company's ability to arrange external financing was materially affected by its weak financial position during 1986 through 1990, but improved in 1991, as a result of the improvement in the Company's financial position. 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 15 months preceding a new debt issuance. Based upon the results of operations for the year ended December 31, 1991, and/or on the basis of previously retired debt, the Company believes it could issue $349,000,000 of first mortgage bonds in addition to the amount presently outstanding (assuming an interest rate of 9 percent for additional first mortgage bonds). First mortgage bonds in a greater amount may also be issuable for the refunding of outstanding first mortgage bonds.

American Municipal Bond Assurance Corporation (AMBAC). The Company has agreements with AMBAC which guarantee the payment of principal and interest on $65,735,000 of pollution control revenue bonds.

During 1990, the Company and AMBAC amended existing agreements which required the Company to place certain amounts into a Permanent Indemnity Reserve which will be released to the Company when the pollution control revenue bonds are fully retired. Additionally, the amendment requires that unless certain financial tests are met, the Company will deposit an additional $1,500,000 a year in an Indemnity Reserve to be released to the Company after such financial tests are met or when the pollution control revenue bonds are retired.

As of December 31, 1991, the Company had issued $82,627,000 of notes (representing 200 percent of the otherwise required cash payment) payable to AMBAC, which are due on April 30, 1993, and had placed $26,438,000, including interest, in the Permanent Indemnity and Indemnity Reserves.

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 (in thousands)	Letter of Credit Expiration
Variable rate due May 1, 2015	$ 41,600	May 28, 1992
Variable rate due November 1, 2015	39,000	November 27, 1992
Variable rate due December 1, 2015	28,400	December 28, 1992
Variable rate due April 1, 2016	20,000	April 27, 1993
10-5/8% due May 1, 2014	50,000	May 15, 1994

During the fourth quarter of 1991, the Company remarketed $94,000,000 of pollution control bonds that had been secured by letters of credit that expired on December 28, 1991.

If the letters of credit that expire in 1992 are 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.

12. Short-Term Lines of Credit

As of December 31, 1991, 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 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 February 28, 1992. The short-term bank credit agreement contains negative covenants which, among other restrictions, restrict the incurrence of additional debt, creation of liens, prepayment of debt (with certain exceptions), payment of dividends, purchase of stock other than to satisfy mandatory sinking fund requirements, sale of assets, and acquisition of assets and require satisfaction of a minimum net worth test. The bank credit agreement is collateralized by the pledge of $100,000,000 principal amount of the Company's first mortgage bonds. The Company is currently negotiating for a new short-term line of credit, which may include a restriction on the payment of common dividends. In January 1992, the Company received a waiver under the short-term credit agreement to pay the remaining preferred stock dividend arrearages.

The Company had no short-term debt outstanding with banks and banking institutions during the three-year period ended December 31, 1991.

13. Purchase Power Agreements

As of December 31, 1991, 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.

	1991	1990	1989
		(in thousands)	
Nelson Unit 6			
Variable costs	$7,679	$7,469	$10,444
Fixed costs	8,184	9,568	13,692

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 $6,000,000 in 1992, to $1,300,000 in 1996.

	1991	1990	1989
		(in thousands)	
River Bend			
Variable costs	$ 6,499	$14,940	$17,341
Fixed costs	23,280	50,312	55,830

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 participants) whereby the Company's Nelson Units 1 and 2 (100 MW each) were sold to a partnership (NISCO) consisting of the participants and the Company.

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

For the years ended December 31, 1991, 1990, and 1989, the purchases of electricity from the joint venture totaled $61,316,000, $62,028,000, and $62,583,000, respectively.

14. Financial Instruments

Temporary Cash Investments. At December 31, 1991 and 1990, the Company had $291,845,000 and $195,345,000 of temporary cash investments invested in repurchase agreements or high grade short-term corporate investments, with nine banks and investment banks. 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.

15. Subsequent Events

First Mortgage Bond Refinancing. In January 1992, the Company sold two new issues of first mortgage bonds totaling $300,000,000. The proceeds were irrevocably deposited with the indenture trustee to be used in February 1992, to retire $282,878,000 principal amount of outstanding first mortgage bonds, which were scheduled to mature, as detailed below:

Principal Amount (in thousands)	Scheduled Maturity Date as of December 31, 1991
$ 8,570	September 23, 1992
8,580	September 23, 1993
100,000	March 1, 1994
100,000	September 1, 2012
65,728	November 1, 2013

Preferred Dividends. On February 13, 1992, the Company's Board of Directors declared $115,692,000 of preferred stock dividends and authorized payment of $34,393,000 of preferred stock sinking fund requirements. The preferred stock dividend declaration includes all remaining preferred dividend arrearages in addition to the March 15, 1992 required payment.

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

1991	Operating Revenue	Operating Income	Income (Loss) Before Extraordinary Item	Net Income (Loss)	Earnings (Loss) Per Average Share of Common Stock Outstanding Before Extraordinary Item	Earnings (Loss) Per Average Share of Common Stock Outstanding
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)**
1990						
First Quarter	$ 380,012	$ 68,207	$ 2,455	$ 2,455	$ (.12)	$ (.12)
Second Quarter	416,212	80,320	(111,039)	(111,039)	(1.17)	(1.17)
Third Quarter	488,186	124,911	60,490	60,490	.41	.41
Fourth Quarter	406,275	59,795	3,812	3,812	(.11)	(.11)

See Note 3 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.

See Note 2 for information regarding the Southern Company settlement recorded in the second quarter of 1990.

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, 1991 and 1990 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, 1991. 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.

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, 1991 and 1990 and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 1991 in conformity with generally accepted accounting principles.

As discussed in Note 3, to the consolidated financial statements, at December 31, 1991 and 1990, 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, 1991, approximately $773 million is not currently being recovered through rates. Further, in 1991 a district court in Texas ruled that the Public Utility Commission of Texas exceeded its authority by including deferred costs in rate base. At December 31, 1991, approximately $165 million of deferred costs are currently being collected in rates. If current regulatory and court orders are not modified, a write-off of all or a portion of such costs and a refund of deferred costs previously collected may be required; however, the extent of such write-off or refund, if any, will not be determined until appropriate rate proceedings and court appeals have been concluded. Management can provide no assurance that the Company will ultimately earn a return on or fully recover these capitalized costs associated with River Bend.

As discussed in Note 2, to the consolidated financial statements, in 1989 the co-owner of River Bend initiated a civil action against the Company seeking, among other things, to recover its investment in River Bend and to annul the River Bend Joint Ownership Participation and Operating Agreement. The ultimate outcome of this proceeding cannot presently be determined. Accordingly, no provision for any liability that may result from its ultimate resolution has been recorded in the accompanying consolidated financial statements.

As discussed in Note 3, to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 101 for portions of its business in 1991 and 1989.

Coopers & Lybrand

Houston, Texas
February 14, 1992

Statistical Summary
For the years ended December 31

	1991	1990	1989	1988	1987
ELECTRIC DEPARTMENT					
Number of customers at year end:					
Residential	**505,927**	498,672	492,054	486,993	484,838
Commercial	**63,522**	63,044	62,469	61,958	61,861
Industrial	**4,538**	4,581	4,511	4,563	4,319
Temporary construction	**2,011**	1,805	1,638	1,477	1,442
Other	**2,695**	2,636	2,605	2,585	2,445
Total Customers	**578,693**	570,738	553,277	557,576	554,905
Sales — Kilowatt-hours (thousands):					
Residential	**6,924,649**	6,833,920	6,473,021	6,326,089	6,208,961
Commercial	**5,460,326**	5,338,449	5,197,356	5,023,755	4,911,378
Industrial	**13,612,197**	13,331,772	12,321,905	12,072,078	11,811,676
Temporary construction	**17,144**	15,399	10,759	13,133	16,241
Other	**1,343,545**	1,464,586	1,191,720	1,482,652	1,485,242
Total Sales	**27,357,861**	27,034,126	25,194,761	24,917,707	24,433,498
Revenue — (thousands):					
Residential	**$ 547,147**	$ 523,911	$ 487,972	$ 452,538	$ 430,392
Commercial	**383,883**	378,253	357,568	331,178	312,544
Industrial	**580,923**	577,436	539,944	510,354	476,871
Temporary construction	**1,648**	1,492	1,075	1,130	1,364
Other	**[illegible]**	115,543	115,315	120,513	109,935
Total Revenue	**$ 1,623,959**	$ 1,596,635	$ 1,501,874	$ 1,415,713	$ 1,330,106
Average Annual KWH Use Per Customer:					
Residential	**13,786**	13,795	13,228	13,029	12,818
Commercial	**86,238**	85,761	83,513	81,339	79,180
Industrial	**2,978,899**	2,944,946	2,703,951	2,717,101	2,744,986
Revenue Per KWH — (cents):					
Residential	**7.90**	7.67	7.54	7.15	6.93
Commercial	**7.03**	7.02	6.88	6.59	6.36
Industrial	**4.27**	4.33	4.38	4.23	4.04
Electric Energy Output — Thousands of KWH:					
Net Generated	**26,581,935**	26,102,741	23,955,660	25,146,780	23,421,700
Net Purchased and Interchanged	**4,027,771**	4,277,621	5,352,485	3,570,812	4,593,232
	30,609,706	30,380,362	29,308,145	28,717,592	28,014,932
System Peak Load — Including Interruptible Load — Megawatts	**5,224**	5,388	5,040	4,915	4,991
Total Capability, Including Contract Purchases at Time of System Peak Load (MW)	**6,471**	6,553	6,609	6,866	6,926
Load Factor	**66.9%**	64.4%	66.4%	66.6%	64.1%
STEAM PRODUCTS DEPARTMENT					
Steam Revenue (thousands)	**$ 46,418**	$ 61,052	$ 69,200	$ 70,728	$ 69,056
Electric Sales — KWH (thousands)	**1,711,488**	1,930,373	2,271,428	2,278,884	2,186,789
Steam Sales — millions of pounds	**13,686**	13,204	11,398	10,494	8,593
GAS DEPARTMENT					
Gas Revenue (thousands)	**$ 31,858**	$ 32,998	$ 36,332	$ 34,036	$ 33,424
Number of Customers at year end	**84,005**	83,164	82,681	82,510	83,003
Output — MM cu. ft. of natural gas purchased	**6,786**	6,215	7,826	7,320	7,305
Sales — MM cu. ft.	**6,746**	6,652	7,072	7,134	7,489
WEATHER DATA					
Cooling degree days (Normal 2,703)	**2,888***	2,948	2,816	2,742	2,660
Percentage change from normal	**6.8**	9.1	4.2	1.4	(1.6)
Heating degree days (Normal 1,841)	**1,665***	1,616	1,684	1,812	1,892
Percentage change from normal	**(9.6)**	(12.2)	(8.5)	(1.6)	2.[illegible]

* Estimated.

Officers

Chairman & President

E. Linn Draper Jr. (12) 49
Chairman of the Board & President [1][a]

Chairman of the Board-Elect & Chief Executive Officer

Joseph L. Donnelly (12) 62
Chairman of the Board-Elect & Chief Executive Officer [1]

Senior Executive Vice President

Edward M. Loggins (33) 61
Senior Executive Vice President-Operations

Senior Vice Presidents

James C. Deddens (8) 63
Senior Vice President-River Bend Nuclear Group

Calvin J. Hebert (29) 57
Senior Vice President-External Affairs

Jack L. Schenck (10) 53
Senior Vice President & Chief Financial Officer [3]

Vice Presidents

William E. Barksdale (34) 60
Vice President-Engineering & Technical Services

William J. Jefferson (11) 62
Vice President-Rates & Regulatory Affairs

Stephen K. Burton (13) 38
Vice President & Treasurer [3]

Cecil L. Johnson (15) 49
Vice President-Legal Services

Amery J. Champagne (18) 48
Vice President-Energy Resources

Clyde W. McBride (14) 39
Vice President-Strategic Planning [3]

Ronald W. Ciesiel (17) 39
Vice President-Computer Applications [2]

J. Lee Miller (9) 51
Vice President-Human Resources

Leslie D. Cobb (31) 56
Vice President & Secretary

James E. Moss (33) 55
Vice President-Marketing

Anthony F. Gabrielle (11) 64
Vice President-Special Projects [2]

Bobby J. Willis (29) 55
Vice President & Controller

Charles D. Glass (42) 63
Vice President-Operations

Jasper F. Worthy (35) 63
Vice President-General Services

Division Vice Presidents

John W. Conley (33) 60
Western Division

J. Ted Meinscher (41) 59
Lake Charles Division

Arden D. Loughmiller (30) 53
Beaumont Division

James D. Watkins (33) 60
Baton Rouge Division

Ronald M. McKenzie (25) 51
Port Arthur Division

Other Officers

Geoffrey G. Galow (11) 34
Assistant Treasurer [3]

Timothy L. Morris (12) 40
Assistant Secretary

( ) Years of service
Ages and years of service as of Dec. 31, 1991
[1] *Effective Jan. 6, 1992*
[a] *Resigned, effective Feb. 29, 1992*
[2] *Effective Jan. 1, 1992*
[3] *Effective Jan. 16, 1992*

Directors

*Robert H. Barrow
General, Retired Commandant
United States Marine Corps
St. Francisville, La. (1984)

**(1)John W. Barton
Vice President-Louisiana
Aircraft Inc. & Owner-
Barton Farms
Baton Rouge, La. (1970)

Joseph L. Donnelly
Chairman of the Board-Elect
& Chief Executive Officer
Beaumont, Texas (1986)

*(2)E. Linn Draper Jr.
Chairman of the Board
& President
Beaumont, Texas (1985)

(1)Martin Goland
President-Southwest
Research Institute
San Antonio, Texas (1983)

Frank W. Harrison Jr.
Consulting Geologist
Lafayette, La. (1990)

William F. Klausing
Retired, Senior Vice President
Irving Trust's Public
Utility Division
New York, N.Y. (1991)

(1)William H. LeBlanc Jr.
Chairman of the Board
Baton Rouge Supply Co. Inc.
Baton Rouge, La. (1974)

*Paul W. Murrill
Retired Chairman of the Board
& Chief Executive Officer
Beaumont, Texas (1978)

Eugene H. Owen
Chairman of the Board &
Chief Executive Officer
Owen & White Inc.
Baton Rouge, La. (1989)

Bookman Peters
CPA and financial consultant
and former Chairman of the Board
& CEO, First City Texas
Bryan, Texas (1990)

Monroe J. Rathbone Jr.
Medical doctor and partner-
The Surgical Clinic
Baton Rouge, La. (1975)

*Sam F. Segnar
Chairman of the Board
Collecting Bank, N.A.
Houston, Texas (1988)

*Bismark A. Steinhagen
Chairman of the Board-
Steinhagen Oil Co. Inc.
Beaumont, Texas (1974)

James E. Taussig
President-Taussig Corp.
Lake Charles, La. (1975)

*Executive Committee

**Chairman, Executive Committee

(1)Will not stand for re-election May 7, 1992
(2)Resigned, effective Feb. 29, 1992

Principal Offices

350 Pine Street
Beaumont, Texas
77701

Divisions

285 Liberty Avenue
Beaumont, Texas
77701

1540 Ninth Avenue
Port Arthur, Texas
77640

Highway 75 North
Conroe, Texas
77301

446 North Boulevard
Baton Rouge,
Louisiana
70802

314 Broad Street
Lake Charles,
Louisiana
70601

Information to Shareholders

Shareholder Questions

Shareholders having questions about their company or about their holdings may contact Shareholder Services personnel at the corporate offices 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 and other information.

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 be transferred, while others 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.

Lost Certificates

If a GSU stock certificate is lost or stolen, written notification should be sent immediately to the company's Shareholder 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.

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 1991 Financial and Statistical Report can be obtained without charge from Leslie D. Cobb, Vice President & Secretary, P.O. Box 2951, Beaumont, Texas 77704.

Notice of Annual Meeting

The 1992 Annual Meeting of shareholders will be held at 2 p.m. Thursday, May 7, 1992, 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 27, 1992. Shareholders are invited to attend, but if they cannot, they are urged to fill out and return their proxies.

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

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ERNST & YOUNG

Audited Financial Statements

Cajun Electric Power Cooperative, Inc.

December 31, 1991

AUDITED FINANCIAL STATEMENTS

CAJUN ELECTRIC POWER COOPERATIVE, INC.

DECEMBER 31, 1991

ERNST & YOUNG

4200 One Shell Square
701 Poydras St.
New Orleans, Louisiana 70139

Phone: 504 581 4200

REPORT OF INDEPENDENT AUDITORS

The Board of Directors
Cajun Electric Power Cooperative, Inc

We have audited the accompanying balance sheets of Cajun Electric Power Cooperative, Inc. (the Cooperative) as of December 31, 1991 and 1990, and the related statements of revenue and expenses, changes in equity and margin (deficit), and cash flows for the years then ended. These financial statements are the responsibility of the Cooperative's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Cajun Electric Power Cooperative, Inc. at December 31, 1991 and 1990, and the results of its operations and its cash flows for the years then ended in conformity with generally accepted accounting principles.

The accompanying financial statements have been prepared assuming the Cooperative will continue as a going concern. As discussed in Note 11 to the financial statements, the Cooperative is involved in significant litigation with Gulf States Utilities Company (GSU) as well as proceedings with the Federal Energy Regulatory Commission (FERC) involving certain transmission charges asserted by GSU. An unfavorable outcome of this litigation or the proceedings at the FERC raises substantial doubt about the Cooperative's ability to continue as a going concern. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

The Cooperative's ability to remain in compliance with the Debt Restructure Agreement and to fully recover the costs of its investment in its utility plant cannot presently be determined as a result of expected annual net deficits as discussed in Note 13 to the financial statements, future rate regulation, and the matters referred to in the preceding paragraph. Additionally, as discussed in Note 13 to the financial statements, the outcome of certain class action litigation cannot presently be determined.

March 13, 1992

Ernst & Young

BALANCE SHEETS
CAJUN ELECTRIC POWER COOPERATIVE, INC.
(IN THOUSANDS)

	December 31 1991	December 31 1990
ASSETS		
UTILITY PLANT		
Electric plant in service	$2,647,370	$2,635,081
Less accumulated depreciation and amortization	555,020	481,523
	2,092,350	2,153,558
Construction work in progress	7,273	10,938
Nuclear fuel at amortized cost	50,398	60,310
Electric plant held for future use	10,182	10,132
	2,160,203	2,234,988
OTHER PROPERTY AND INVESTMENTS		
Nonutility property	687	687
Restricted funds held by trustees	2,167	2,027
Investments in associated organizations	53,356	50,847
Decommissioning reserve funds	10,792	8,297
	67,002	61,858
CURRENT ASSETS		
Cash and cash equivalents	36,552	31,997
Accounts receivable - electric customers:		
Members	28,249	31,309
Nonmembers	8,195	9,518
Accounts receivable other	2,008	2,801
Fuel and supplies inventories	39,319	34,727
Prepayments	8,707	2,356
	123,030	112,708
DEFERRED CHARGES	2,995	2,861
	$2,353,230	$2,412,415

	December 31 1991	December 31 1990
EQUITY AND LIABILITIES		
EQUITY AND MARGIN (DEFICIT)		
Memberships	$ 1	$ 1
Patronage capital credits	35,988	36,533
Unallocated deficit	(1,210,442)	(952,738)
Donated capital	406	406
	(1,174,047)	(915,798)
LONG-TERM DEBT, LESS CURRENT PORTION	3,491,626	3,241,261
CURRENT LIABILITIES		
Accounts payable	359	482
Taxes other than income tax	773	240
Accrued interest and other expenses	23,277	23,490
Current portion of long-term debt	450	54,443
	24,859	78,655
DECOMMISSIONING RESERVES	10,792	8,297
	$2,353,230	$2,412,415

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF REVENUE AND EXPENSES
CAJUN ELECTRIC POWER COOPERATIVE, INC.
(IN THOUSANDS)

	Year Ended December 31 1991	1990
OPERATING REVENUE		
Sales of electric energy:		
Members	$ 280,007	$ 289,580
Nonmembers	106,810	129,646
Other	744	1,147
	387,561	420,373
OPERATING EXPENSES		
Power production:		
Fuel	152,356	156,177
Operations and maintenance	71,402	65,400
Purchased power	5,913	6,321
Other power supply expenses	477	680
Transmission	36,167	45,125
Administrative and general	25,818	23,298
Depreciation and amortization	75,879	74,774
Taxes, other than income	3,503	3,273
	371,515	375,048
OPERATING MARGIN	16,046	45,325
OTHER INCOME AND EXPENSES		
Interest, rents and leases	4,864	7,838
Other income	1,596	190
Loss on asset dispositions	(2,582)	(7,425)
Litigation settlements	7,436	(10,378)
	11,314	(9,775)
MARGIN BEFORE INTEREST AND OTHER DEBT EXPENSE	27,360	35,550
INTEREST AND OTHER DEBT EXPENSE	285,064	279,078
NET DEFICIT	$(257,704)	$(243,528)

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CHANGES IN EQUITY AND MARGIN (DEFICIT)
CAJUN ELECTRIC POWER COOPERATIVE, INC.
(IN THOUSANDS)

Years Ended December 31, 1991 and 1990

	Memberships	Patronage Capital Credits	Unallocated Deficit	Donated Capital	Total
BALANCE JANUARY 1, 1990	$ 1	$36,533	$ (709,210)	$406	$ (672,270)
Net deficit for the year			(243,528)		(243,528)
BALANCE DECEMBER 31, 1990	1	36,533	(952,738)	406	(915,798)
Net deficit for the year			(257,704)		(257,704)
Patronage capital retired		(545)			(545)
BALANCE DECEMBER 31, 1991	$ 1	$35,988	$(1,210,442)	$406	$(1,174,047)

The accompanying notes are an integral part of these financial statements.

STATEMENT OF CASH FLOWS
CAJUN ELECTRIC POWER COOPERATIVE, INC.
YEAR ENDED DECEMBER 31, 1991
(IN THOUSANDS)

CASH FLOWS FROM OPERATING ACTIVITIES	
Cash received from sales of power	$ 390,763
Payments from joint owner of Big Cajun 2, Unit 3	21,377
Other cash receipts	2,568
Cash payments for fuel and fuel stock	(150,929)
Operation and maintenance expenses paid	(81,918)
Purchased power and transmission expenses paid	(41,791)
Administrative and general expenses paid	(29,783)
Taxes paid	(3,284)
Interest and other income received	7,375
Purchased power and transmission refunds	10,212
Interest paid	(37,633)
NET CASH PROVIDED BY OPERATING ACTIVITIES	86,957
CASH FLOWS FROM INVESTING ACTIVITIES	
Capital expenditures	13,888
Nuclear fuel purchased	6,045
NET CASH USED BY INVESTING ACTIVITIES	19,933
CASH FLOWS FROM FINANCING ACTIVITIES	
Repayment of long-term debt	54,476
Note A prepayment	7,448
Retirement of capital credits	545
NET CASH USED BY FINANCING ACTIVITIES	62,469
INCREASE IN CASH AND CASH EQUIVALENTS	4,555
Cash and cash equivalents at beginning of year	31,997
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 36,552

RECONCILIATION OF NET DEFICIT TO NET CASH PROVIDED BY OPERATING ACTIVITIES

Net deficit	$(257,704)
ADJUSTMENTS TO RECONCILE NET DEFICIT TO CASH PROVIDED BY OPERATING ACTIVITIES	
Depreciation and amortization	73,710
Amortization of nuclear fuel	17,932
Interest expense accrued to long-term debt	252,254
Book value of asset dispositions	2,050
Gain on REA adjustment of Note B	(1,488)
Decrease in accounts receivable and investments in associated organizations	2,528
Increase in fuel and prepayments	(3,630)
Increase in accounts payable and accrued expenses	1,305
NET CASH PROVIDED BY OPERATING ACTIVITIES	$ 86,957

The accompanying notes are an integral part of these financial statements.

STATEMENT OF CASH FLOWS
CAJUN ELECTRIC POWER COOPERATIVE, INC.
YEAR ENDED DECEMBER 31, 1990
(IN THOUSANDS)

OPERATING ACTIVITIES	
Net deficit	$(243,528)
Adjustments to reconcile net deficit to net cash used by operating activities:	
Depreciation and amortization	73,099
Amortization of nuclear fuel	15,446
Amortization and write off of deferred charges and credits - net	8,595
Interest expense accrued to long-term debt	157,250
Interest income on long-term receivable	(1,395)
Patronage capital credits	(3,858)
Book value of asset dispositions	5,213
Decrease in accounts receivable	6,963
Decrease in fuel and supplies inventories	5,221
Increase in prepayments	(1,856)
Decrease in accounts payable	(424)
Decrease in accrued interest and other expenses	(65,996)
NET CASH USED	(45,270)
INVESTING ACTIVITIES	
Capital expenditures	(24,358)
Increase in investments and restricted funds held by trustee	(1,334)
Increase in deferred charges	(2,080)
Collection of other receivables	26,015
NET CASH USED	(1,757)
FINANCING ACTIVITIES	
Proceeds from payments made by REA as guarantor	134,052
Repayment of long-term debt and debt classified as current prior to debt restructure	(124,388)
NET CASH PROVIDED	9,664
DECREASE IN CASH AND CASH EQUIVALENTS	(37,363)
Cash and cash equivalents at beginning of year	69,360
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 31,997

The accompanying notes are an integral part of these financial statements.

NOTES TO FINANCIAL STATEMENTS

CAJUN ELECTRIC POWER COOPERATIVE, INC.

DECEMBER 31, 1991

NOTE 1 - SIGNIFICANT ACCOUNTING POLICIES

General: Cajun Electric Power Cooperative, Inc., (the Cooperative) is a rural electric generation and transmission cooperative wholly owned by 13 member distribution cooperatives (the Members) which provide electricity to approximately 300,000 metered customers representing nearly 1,000,000 people residing throughout 80% of the land area of Louisiana. The Cooperative and its 13 Members have entered into wholesale all requirements power contracts which require the Members to purchase all of their electric energy requirements from the Cooperative generally through 2026. The Cooperative is subject to certain rules and regulations promulgated for rural electric borrowers by the Rural Electrification Administration (REA) and is also subject to the jurisdiction of the Louisiana Public Service Commission (LPSC) (see Note 12).

System of Accounts: The Cooperative maintains its accounting records in accordance with the Federal Energy Regulatory Commission (FERC) chart of accounts as modified and adopted by the REA.

Electric Plant In Service: Electric plant in service is stated on the basis of cost. Depreciation is computed using the straight-line method over the expected useful lives of the related component assets. The net book value of units of property replaced or retired, including costs of removal net of any salvage value, is charged to operations.

Nuclear Fuel: The cost of nuclear fuel, including capitalized interest, is amortized to fuel expense on the basis of the actual number of units of thermal energy produced, multiplied by a unit cost which reflects the total thermal units expected to be produced over the life of the fuel (see Note 9).

Note 1 - Continued

Construction Work In Progress: Construction work in progress is stated on the basis of cost, net of the amounts applicable to a joint owner, and includes interest during construction on major projects.

Investments: The Cooperative has investments in The National Rural Utilities Cooperative Finance Corporation (CFC) and the National Bank for Cooperatives (CoBank) which are in the form of capital term certificates and Class "C" and "E" stock, respectively. In the accompanying financial statements, these investments are carried at cost and include undistributed patronage capital credits from these organizations.

Fuel and Supplies Inventories: Fuel and supplies inventories are stated on the basis of cost utilizing the weighted average cost method of inventory valuation.

Decommissioning: Decommissioning reserves represent cumulative accruals for decommissioning expense. The annual charge for decommissioning expense is the required addition to the decommissioning trust funds such that the balance of the funds (contributions plus net earnings) will be sufficient to satisfy estimated decommissioning costs at the end of the expected useful lives of the Cooperative's facilities (see Note 9).

Income Taxes: Certain revenue and expense items are recognized in different periods for financial reporting and income tax purposes thus creating timing differences. Deferred income taxes are provided on these timing differences which are principally related to depreciation on electric plant in service and the sale of tax benefits. The Cooperative uses the flow-through method of recognizing general business credits (see Note 6).

Patronage Capital Credits: The Cooperative is organized and operates on a not-for-profit basis. Patronage capital credits represent that portion of the Cooperative's net margins which have been allocated to Member cooperatives. As provided in the Cooperative's bylaws, all amounts received from the furnishing of electric energy in excess of the sum of operating costs and expenses and amounts required to offset any current year losses are assigned to Members' patronage capital credit accounts on a patronage basis or, at the discretion of the Board of Directors, may be offset against losses of any prior fiscal year. All other amounts received from operations

Note 1 - Continued

in excess of costs and expenses may be used to offset losses incurred during the current or any prior fiscal year and, to the extent not needed therefore, are allocated to Members on a patronage basis. The Cooperative may also retire previously allocated patronage capital credits out of its Retained Share (see Notes 4 and 12). In accordance with the Cooperative's bylaws, the net deficits have not been allocated to the Member cooperatives.

Statement of Cash Flows: As a result of additional cash reporting requirements to the REA, the Cooperative adopted the direct method of reporting cash flows for the year ended December 31, 1991. The statement of cash flows for the year ended December 31, 1990 was prepared using the indirect method as previously presented.

Cash Equivalents: The Cooperative considers all highly liquid investments with a maturity of three months or less when purchased to be cash equivalents.

Reclassifications: Certain reclassifications have been made to the 1990 financial statements to conform to the 1991 presentation.

NOTE 2 - UTILITY PLANT

Electric plant in service at December 31 consisted of the following (in thousands):

	1991	1990
Production:		
Nuclear	$1,476,734	$1,475,098
Coal	1,023,144	1,015,450
Gas	32,597	31,708
Transmission	97,681	96,672
General	17,214	16,153
	$2,647,370	$2,635,081

Generating Unit	Net Megawatt Rating	Fuel	Cooperative Ownership Percentage	Cooperative Ownership Megawatts
River Bend	936	Nuclear	30%	281
Big Cajun 2, Unit 1	540	Coal	100%	540
Big Cajun 2, Unit 2	540	Coal	100%	540
Big Cajun 2, Unit 3	540	Coal	58%	313
Big Cajun 1, Unit 1	105	Gas	100%	105
Big Cajun 1, Unit 2	105	Gas	100%	105

Note 2 - Continued

River Bend and Big Cajun 2, Unit 3 are jointly owned by the Cooperative and Gulf States Utilities Company (GSU) (see Note 11). Construction work in progress consists of improvements and additions to existing plants. The estimated cost to complete these projects at December 31, 1991 was approximately $6.3 million.

Nuclear fuel represents the Cooperative's 30% share of River Bend fuel and as of December 31 consisted of the following (in thousands):

	1991	1990
Nuclear fuel in process	$ 22,263	$ 14,243
Nuclear fuel in stock	177	177
Nuclear fuel in reactor	78,978	78,978
Spent nuclear fuel	40,948	40,948
	142,366	134,346
Less nuclear fuel amortization	91,968	74,036
Net nuclear fuel	$ 50,398	$ 60,310

Nuclear fuel in process represents the accumulated cost, including capitalized interest, of fuel required for the fourth reload and a portion of the fifth reload. The fuel is in various stages of conversion, enrichment or fabrication. Spent nuclear fuel consists of the original cost of nuclear fuel assemblies, in the process of cooling, removed from the reactor during each of the three previous reloads.

Land relating to an abandoned lignite project has been retained as a possible site for a future generating facility and its cost, $9.8 million, is included in electric plant held for future use.

The net change in accumulated depreciation and amortization for the years ended December 31 was (in thousands):

	1991	1990
Charged to operating expenses	$73,710	$73,099
Charged to fuel inventories and other assets	1,301	1,268
	75,011	74,367
Less asset disposals	1,514	3,491
	$73,497	$70,876

NOTE 3 - INVESTMENTS IN ASSOCIATED ORGANIZATIONS

Investments in associated organizations at December 31 consisted of the following (in thousands):

	1991	1990
CFC	$ 7,704	$ 7,704
CoBank	44,244	41,819
Other	1,408	1,324
	$53,356	$50,847

NOTE 4 - LONG-TERM DEBT

On December 21, 1990, the Cooperative consummated a Debt Restructure Agreement (DRA) effective May 31, 1990, with the United States of America acting through the REA. Under the terms of the DRA, the Cooperative executed and delivered to REA two notes which restructured all of the Cooperative's debt to or guaranteed by the REA: Note A, in the original face amount of $2,147,994,670 which matures on December 31, 2026 and Note B, in the original face amount of $1,037,007,550 which has a final maturity date of December 31, 2036. Both Notes A and B bear interest on the unpaid principal balance at a nominal rate of 8.64% with an assumed effective annual rate of 8.99%. Any accrued but unpaid interest on Notes A or B is added to principal on a monthly basis. The DRA provides that Note A may not be prepaid without the express written consent of REA. Note B may be prepaid without premium or penalty.

The DRA requires that Note A be paid in varying annual installments. Under the terms of the DRA, so long as the annual amount due under the Note A debt service schedule has not been paid in full, on the fifteenth business day of each month the Cooperative pays to REA all cash balances at the end of the preceding month in excess of the general funds cap ($35,000,000 adjusted in accordance with the DRA).

Payments on Note B prior to 2027 are contingent upon several factors, including Member and nonmember sales growth, extraordinary cash receipts and the existence of cash in excess of the general funds cap at any month-end after the annual Note A required payment has been made. The existence of such excess cash will also result in additions to the Cooperative's Retained Share, which represents the amount of cash which the Cooperative may utilize for any valid corporate purpose, including

Note 4 - Continued

the payment of previously allocated capital credits (see Note 12). The required Note B payment for 1991 is approximately $872,000 which will be paid in April, 1992. On February 25, 1991, the Cooperative's Board of Directors approved a distribution to the Members of the balance of the Cooperative's Retained Share in the amount of $544,552 to pay previously allocated capital credits. The distribution was made on March 5, 1991. At December 31, 1991, the Cooperative's Retained Share was approximately $1,778,000.

The DRA provides that the unpaid principal amount of Note B as of December 31, 2026 will be restructured as follows: The Cooperative will have the fair market value of its assets appraised as of December 31, 2026. An amount equal to sixty percent of the appraised value shall be paid in equal annual installments over the next ten years ending December 31, 2036 at the same interest rate, accrued and compounded monthly in the same manner as the present Note A. The remaining balance of Note B as of December 31, 2026 will be repaid over the subsequent ten year period in a manner consistent with the terms and conditions associated with Note B of the DRA. Any amount unpaid at December 31, 2036 will be due and payable in full as of that date.

Under the terms of the DRA, the Cooperative's debt which was in default prior to the DRA, and was guaranteed by the REA (the REA related debt: notes payable to the Federal Financing Bank, the Cooperative Utility Trusts and CoBank) which is included in the restructured Notes A and B, was not retired or defeased but remains outstanding. The DRA requires REA to make all of its guaranteed payments on the REA related debt in a timely manner, and, so long as no event of default has occurred under the DRA, REA agrees not to exercise any remedy it may have under the REA related debt documents. Additionally, the REA related debt will not be deemed satisfied until the Cooperative satisfies in full the requirements of Notes A and B. Under the terms of the DRA, in the event of default, REA may seek remedies under either the terms of the DRA or the REA related debt documents.

A portion of the underlying restructured REA related debt, aggregating $522 million at December 31, 1991, bears interest at variable rates, for which the Cooperative bears the interest rate risk. If the actual interest cost of this debt in any year is less than the benchmark amount set forth in the DRA, the difference will be added

Note 4 - Continued

to the Cooperative's Retained Share. If the actual interest cost is greater, the Cooperative must pay the difference to the REA.

Long-term debt at December 31 consisted of the following (in thousands):

	1991	1990
Note A to REA, due in varying annual installments through 2026, interest at 8.64% compounded monthly.	$2,305,862	$2,149,284
Note B to REA, varying annual payments, based upon several contingent factors, final maturity December 31, 2036, interest at 8.64% compounded monthly.	1,183,514	1,089,276
Citibank agreement, due June 1991.		48,870
Industrial Development Revenue Bonds, series 1982, interest at two-thirds of prime rate (4.4% at December 31, 1991), due in 6 annual installments from 1992 through 1997.	2,700	3,150
River Bend construction and operations commitment, interest at a variable rate.		5,124
Less current portion of long-term debt	450	54,443
	$3,491,626	$3,241,261

Scheduled maturities of long-term debt including Note A principal and interest payments are (in thousands):

1992	$ 120,450
1993	135,450
1994	170,450
1995	170,450
1996	175,450
Thereafter	8,050,450
	$8,822,700

Note 4 - Continued

Interest and other debt expense incurred on long-term debt for the years ended December 31 consisted of the following (in thousands):

	1991	1990
Interest charged to operating expense	$284,554	$270,768
Other debt expense	510	8,310
Total interest and other debt expense	285,064	279,078
Capitalized interest on nuclear fuel	1,429	848
	$286,493	$279,926

For the year ended December 31, 1991, the Cooperative paid $37.6 million in interest. For the year ended December 31, 1990, the Cooperative and the REA on behalf of the Cooperative, paid interest of approximately $189.3 million.

Substantially all of the Cooperative's assets are pledged to secure the Cooperative's debt to REA by the Supplement to the Supplemental Mortgage and Security Agreement (the REA mortgage) executed November 28, 1990 between the Cooperative, REA and CoBank in order to facilitate the DRA. Both the REA mortgage and the DRA contain certain restrictive covenants including limitations on indebtedness, capital additions, distributions to Members and an agreement not to lower the Cooperative's wholesale electric rate for the term of the DRA. At December 31, 1991, the Cooperative was in compliance with all such covenants. Certain office facilities in Baton Rouge are separately pledged to secure Industrial Development Revenue Bonds.

CoBank is secured by the REA Mortgage for two letters of credit amounting to approximately $58.6 million supporting potential indemnity payments under sale-leaseback transactions completed in 1983. During 1988, CoBank renewed the letters of credit for an additional five-year period.

During 1991, the Cooperative received a refund of $7.4 million resulting from the settlement of a FERC rate case. On October 8, 1991, in accordance with the terms of the DRA, this refund, included in prepayments in the accompanying 1991 balance sheet, was transferred to REA and is to be applied to the required Note A payment for 1992.

NOTE 5 - SHORT-TERM INVESTMENTS

At December 31, 1991, the Cooperative's cash was invested in U.S. Treasury securities, U.S. government agencies securities, commercial paper and short-term obligations issued by financial institutions. All investments conform with the guidelines established by the REA. Maturities are selected to correspond with cash flow requirements and are generally for periods of less than three months and are considered to be cash equivalents.

NOTE 6 - INCOME TAXES

The Cooperative had no current or deferred income tax provisions for the years ended December 31, 1991 and 1990.

At December 31, 1991, the Cooperative had a general business credit carryforward of approximately $166 million, of which approximately $9 million expires in 1999; $27 million in 2000; $128 million in 2001; and $2 million in 2002.

In addition, the Cooperative has loss carryforwards of approximately $1.5 billion which may be used to offset future taxable income. The expiration dates and amounts of the net operating loss portion of the total loss carryforwards are as follows (in thousands):

2004	$ 14,955
2005	231,809
2007	95,800
	$342,564

The remaining losses of approximately $1.2 billion are attributable to Member activities and may be carried forward indefinitely.

The Cooperative has available approximately $173 million in net operating loss carryforwards for alternative minimum tax purposes, $101 million of which expire in 2005, with $72 million expiring in 2007.

Note 6 - Continued

Also, the Cooperative has approximately $1.2 billion of losses attributable to Member activities for alternative minimum tax purposes which may be carried forward indefinitely. Additionally, approximately $166 million of the general business credit carryforwards of the Cooperative may be used to offset future alternative minimum tax. These credits expire in the same years as the general business credit carryforwards for regular tax purposes.

In February 1992, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards (SFAS) No. 109, Accounting for Income Taxes, which supersedes SFAS No. 96 and is effective for fiscal years beginning after December 15, 1992. The extent of the impact of SFAS No. 109 on the Cooperative has not been determined.

NOTE 7 - EMPLOYEE BENEFIT PLAN

All of the Cooperative's employees participate in the National Rural Electric Cooperative Association (NRECA) Retirement and Security Program once they have met minimum service requirements. The Cooperative makes annual contributions to the plan equal to the amounts accrued for pension expense. In this master multiple-employer defined benefit plan, which is available to all member cooperatives of the NRECA, the accumulated benefits and plan assets are not determined or allocated separately by individual employer. As a result of a better than anticipated return from the plan's investments, the Cooperative was not required to make contributions to the plan in 1991 or 1990.

NOTE 8 - RELATED PARTY TRANSACTIONS

In December 1986, the Cooperative purchased certain substation equipment owned by eight Members in order to better define the operating responsibilities of the transmission system. The aggregate purchase price of $12.4 million was partially financed by the Cooperative assuming long-term notes payable to the REA in the amount of $8.4 million. In addition, the Cooperative agreed to make payments to certain of its Members. During 1990, the Cooperative made payments of $2.2 million under the terms of this agreement. Effective March 1, 1991, the REA reduced the principal balance of Note B by $2.3 million in a final adjustment of the substation transfer debt.

NOTE 9 - SPENT NUCLEAR FUEL AND DECOMMISSIONING RESERVES

GSU has executed a contract with the Department of Energy (DOE) whereby the DOE will furnish disposal service for the spent nuclear fuel from River Bend. Currently, the cost amounts to one-tenth of one cent per kilowatt hour of net generation. The DOE spent nuclear fuel fee is subject to change in accordance with the provisions of the Nuclear Waste Policy Act of 1982.

The Nuclear Regulatory Commission in 1988 issued final regulations setting forth the technical and financial criteria for decommissioning licensed nuclear facilities. The regulations require electric utilities either to certify that a minimum dollar amount will be available to decommission the facility or to submit a decommissioning funding plan. In addition, these regulations require that financial assurance be provided by either prepayment, an external sinking fund, or by a surety, insurance, or other form of guarantee. In response to these regulations, on December 2, 1988, the Cooperative established an external grantor trust, the River Bend Decommissioning Trust Fund, and intends to make annual contributions to accumulate an amount which will be sufficient, based on current estimates and assumptions, to pay for its share of the cost of decommissioning at the end of the estimated useful life of River Bend. Annual contributions to the trust are approximately $1.4 million. As of December 31, 1991, the balance in the River Bend Decommissioning Trust Fund was $9.3 million.

The Cooperative is required by the State of Louisiana Department of Environmental Quality (DEQ) to provide assurance that it has the ability to fund the actions which will be necessary to rehabilitate its Big Cajun 2 ash and wastewater impoundment areas which, as disposal sites, are subject to DEQ review and supervision. The total liability for funding the solid waste disposal site rehabilitation is currently estimated to be approximately $4 million, of which GSU is responsible for approximately $500,000. On July 1, 1989, the Cooperative created the Solid Waste Disposal Trust and deposited $1.06 million with the trustee in satisfaction of its DEQ funding requirements. The annual contributions to the trust are approximately $116,000. The actual payments for site rehabilitation are not scheduled to occur until the end of the estimated useful life of the Big Cajun 2 coal-fired facility. The balance in the Solid Waste Disposal Trust at December 31, 1991 was $1.5 million.

NOTE 10 - NUCLEAR INSURANCE

The ownership of an undivided interest in River Bend subjects the Cooperative to certain risks. The Cooperative is insured, as described below, for public liability and property damage.

The Price-Anderson Act (the Act) was renewed by Congress in 1988 and was extended through August 1, 2002. Public liability under the Act for any nuclear incident is currently limited to $7.8 billion. The Cooperative and GSU are insured for this exposure by private insurance as well as by a secondary financial program. Changes to the Act related to the secondary financial program may require the Cooperative to become subject to a possible retroactive assessment of which the Cooperative's share would not exceed $19.8 million per incident with a maximum of $3 million per incident payable in any one year for losses at any licensed nuclear facility.

The Cooperative, together with GSU, maintains $500 million of property damage insurance and $765 million of excess insurance related to River Bend obtained from the private insurance market. Additionally, the Cooperative is a member-insured of the Nuclear Electric Insurance Limited (NEIL II) program which provides $1.25 billion of excess property insurance. As a member-insured of NEIL II, the Cooperative is subject to a maximum assessment of $2.0 million in any one policy year. Although the Cooperative and GSU continue to attempt to increase insurance coverage as it becomes available, the Cooperative can give no assurance as to the adequacy of its coverage in the event of a major accident. Total available property damage insurance is substantially less than the potential insurable value of River Bend. In 1991, the Nuclear Regulatory Commission promulgated a rule providing that, in the event of an accident at River Bend in which the estimated costs of stabilizing and decontaminating the site exceed $100 million, insurance proceeds must first be dedicated to this purpose. Proceeds not required for such stabilization and decontamination may then be used to repair or replace the damaged unit. The Cooperative has joined GSU in establishing a Nuclear Workers' Liability policy which covers liability for the claims of workers employed at River Bend after January 1, 1988 for noncatastrophic nuclear related injury such as prolonged exposure to low-level radiation. Any claims by workers employed at River Bend prior to January 1, 1988 will continue to be covered under the Nuclear Workers' Liability

Note 10 - Continued

policy if the claim is made by December 31, 1997. Under the Nuclear Workers' Liability policy, the Cooperative is subject to a maximum potential retrospective premium assessment of approximately $1.0 million. It is possible that liabilities related to the release or escape of a hazardous substance from River Bend may be greater than the coverage on policies currently carried and, consequently, existing insurance may not be sufficient to meet all possible liabilities or losses. The Cooperative cannot provide assurance that it will be able to maintain coverage at present levels. Any liability or loss in excess of that covered under existing policies could have a material adverse effect upon the Cooperative.

NOTE 11 - GULF STATES UTILITIES COMPANY

In August 1979, the Cooperative and GSU entered into a contractual agreement for the joint ownership of River Bend (see Note 2). The Cooperative has a 30% undivided interest in River Bend and is responsible for 30% of River Bend's costs of construction, capital additions and operations. GSU is the operator of the facility. GSU paid the Cooperative approximately $29 million in 1991 and $66 million in 1990, completing a five-year capacity and energy sellback agreement related to River Bend.

In November 1980, the Cooperative and GSU entered into a contractual agreement for the joint ownership of Big Cajun 2, Unit 3, and certain common facilities at Big Cajun 2 (see Note 2). The Cooperative retained a 58% undivided ownership interest in Unit 3 and an 86% undivided ownership interest in the common facilities. The Cooperative is the operator of the Big Cajun 2 facilities.

The Cooperative filed suit on June 26, 1989 against GSU in United States District Court in Baton Rouge alleging fraud in the inducement to enter into the River Bend Joint Ownership Participation and Operating Agreement (JOPOA) as well as misrepresentation, mismanagement, breach of fiduciary duty and breach of contract. The Cooperative seeks the annulment of the River Bend JOPOA and the recovery of its investment in River Bend (approximately $1.6 billion) as well as damages resulting from the Cooperative's participation in the River Bend project. The Cooperative is seeking further damages associated with excessive operating costs of the facility which arose due to GSU's alleged mismanagement. On November 7, 1990, GSU filed an amended counterclaim with the court requesting that the Big Cajun 2, Unit 3 JOPOA be

Note 11 - Continued

rescinded and asked for an appropriate monetary judgment sufficient to place the Cooperative and GSU in the same position as if the Big Cajun 2, Unit 3 JOPOA were never consummated. Additionally, GSU's counterclaim asserts that its present transmission arrangements with the Cooperative should be terminated by the court. Further GSU asserts that in any event it is entitled to monetary damages resulting from an alleged breach of contract and fiduciary duty by the Cooperative. The timing or outcome of these matters is uncertain.

In September 1991, the Cooperative exercised its options under the River Bend JOPOA and elected not to participate in the funding of the Service Water Project (SWP) and the inlet feedwater nozzle repair or replacement. These projects, which are expected to be completed in 1993, are estimated to cost a total of approximately $60 million. Consequently, through the end of December 1991, the Cooperative has not paid approximately $6 million related to the SWP. GSU asserts that the Cooperative is in default of the JOPOA and disputes the Cooperative's right to not pay such amounts. The amounts not paid are based on the Cooperative's best estimate of the related costs to date and are not reflected in the accompanying financial statements. On November 27, 1991, the Cooperative filed a complaint for Declaratory and Injunctive Relief with the United States District Court, Middle District of Louisiana seeking a declaration and interpretation of the Cooperative's rights as related to this issue under the JOPOA. The timing or outcome of this matter is uncertain, although legal counsel has advised the Cooperative that it is within its rights under the JOPOA to withhold such payments.

On July 17, 1987, the Cooperative filed a complaint with the FERC against GSU alleging overbilling and improper cost allocations for certain transmission service charges. On May 11, 1989, a FERC administrative law judge issued an initial opinion which could require the Cooperative to pay GSU approximately $25 million for transmission charges for the period 1981 through 1991. The FERC will make a final determination on the initial opinion which may increase, reduce or eliminate the Cooperative's potential liability to GSU. After final FERC action, either party may pursue further appeals through the federal court system. At December 31, 1991, GSU alleges that the Cooperative had underpaid these transmission charges in the amount of approximately $105 million. The timing or outcome of this matter is uncertain. Accordingly, no provision for any liability that may result has been made in the financial statements.

Note 11 - Continued

An unfavorable outcome of the SWP litigation or the proceedings at the FERC as discussed in the two preceding paragraphs could have a material adverse impact upon the Cooperative.

NOTE 12 - RATES AND REGULATION

The Cooperative is regulated by the LPSC with respect to rates and certain other matters. The Cooperative must also seek approval from REA for rate changes.

In May 1990, the LPSC ordered the Cooperative to reduce the base rate to its Members by 4 mills per KWh replacing a fuel credit of approximately the same amount which the Cooperative had been flowing through its fuel adjustment.

In July 1990, the LPSC approved the DRA with certain conditions. One of these conditions was that the Cooperative's average annual rate to its Members in 1990 and 1991 be no higher that 54.5 mills per KWh.

In January 1991, the LPSC held hearings on the Cooperative's rate design and in April 1991 issued an extensive data request to the Cooperative in conjunction with its examination of the Cooperative's rates.

In August 1991, after receiving permission from REA as required by the DRA, the Cooperative filed a request with the LPSC to reduce the 4 mill credit imposed in May 1990 to a 1 mill credit in three increments over ten months beginning in October 1991. This proposed base rate increase was intended to maintain level rates through 1992. Hearings were held in December 1991 at which time the Cooperative modified its request and altered the timing of the change in the credit. At its February 4, 1992 meeting, the LPSC approved the Cooperative's modified request for a 3 mill reduction of the credit effective for the first and last quarters of 1992 and a 2 mill reduction of the credit effective for the second and third quarters of the year. Additionally, the LPSC ordered the 54.5 mill per KWh cap on rates be continued and prohibited the Cooperative from paying capital credits during 1992 from its Retained Share.

Note 12 - Continued

The LPSC has issued a procedural schedule to continue its examination of the Cooperative's rates during 1992. The Cooperative intends to make a filing with the LPSC in early 1992 regarding rates for 1993 and beyond.

NOTE 13 - COMMITMENTS AND CONTINGENCIES

Equity And Margin (Deficit): The Cooperative expects to incur continuing and substantial annual net deficits for the foreseeable future and also expects that its Unallocated Deficit [a component of equity and margin (deficit)] will continue to increase principally because of interest expense that is accrued but not paid. The debt restructure completed in 1990 recognized that the Cooperative was unable and would continue to be unable to pay previously scheduled debt service (principal and interest) on all of its debt and therefore split substantially all of its future debt service obligations into fixed and contingent components in order to avoid forcing a restructure or reorganization under the bankruptcy code.

In accordance with Generally Accepted Accounting Principles, the Cooperative continues to accrue the interest expense on Note A and Note B, however, payments on Note A are based on a nontypical amortization schedule specifically set forth in the DRA while payments on Note B prior to 2027 are required only when certain contingent events occur (see Note 4). The interest that is accrued but not paid is added to the balances of the notes each month thereby increasing the debt of the Cooperative. The interest expense that is accrued but not paid will continue to cause annual net deficits and a deteriorating net worth, but neither is an event of default.

Gulf States Utilities Company: As discussed more fully in Note 11, the Cooperative is involved in significant litigation with GSU as well as proceedings at the FERC.

Coal and Transportation Commitments: Purchases under the terms of contracts for the acquisition and related transportation of coal during 1991 and 1990 were approximately $121 million annually. Certain purchases are subject to various price escalators and deflators, minimum quantity takes and periodic price reopeners at then current market prices. Management is of the opinion that these contracts will properly meet anticipated coal supply needs. The transportation contracts begin to expire in 1999 while the coal contracts are for the useful life of the coal-fired

Note 13 - Continued

generating facility provided the present supplier is willing to meet or better offers from other suppliers at scheduled periodic price reopeners.

Litigation: On September 20, 1989, a class action petition was filed in the Tenth Judicial District State Court in Natchitoches Parish, Louisiana naming the Cooperative's Members as defendants. The plaintiffs in this action seek a refund of all rate increases enacted by the Cooperative's Members from 1978 until the respective Member voted to be subject to the jurisdiction of the LPSC or was placed under the jurisdiction of the LPSC by action of the State Supreme Court. On October 17, 1989, the case was moved to the federal courts. On June 23, 1990, motions were filed by the Cooperative's Members to name the Cooperative as a third party defendant in the case. On July 15, 1991, the U. S. District Court in New Orleans entered an order retaining jurisdiction in the case and granting the motions of the Cooperative's Members to enjoin the Cooperative as a third party defendant in the case. The timing or outcome of this matter is uncertain and no provision for any liability that may result has been made in the financial statements. An unfavorable outcome could have a material adverse impact upon the Cooperative.

On December 13, 1990, Sam Rayburn G&T Cooperative, Inc. (SRG&T) filed suit against the Cooperative in a Texas state court seeking specific performance by the Cooperative of a contract to provide for the sale of a 7% undivided ownership interest in Big Cajun 2, Unit 1. The contract had expired, according to its terms, on June 1, 1990. Further, SRG&T petitioned the court to rule, if specific performance is not granted, that a firm power sales contract between SRG&T and the Cooperative be declared null and void. In February 1992, the parties agreed in principle to a settlement pursuant to which SRG&T will dismiss its suit and abide by the terms and conditions of the firm power sales contract.