GEORGIA POWER

A SOUTHERN COMPANY

02033416

2001 ANNUAL REPORT

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CONTENTS

Georgia Power Company 2001 Annual Report

SUMMARY

	2001	2000	Percent Change
Financial Highlights *(in millions)*:			
Operating revenues	\$4,966	\$4,871	2.0
Operating expenses	\$3,754	\$3,637	3.2
Net income after dividends on preferred stock	\$610	\$559	9.1
Operating Data:			
Kilowatt-hour sales *(in millions)*:			
Retail	72,545	74,434	(2.5)
Sales for resale – non-affiliates	8,110	6,464	25.5
Sales for resale – affiliates	3,133	2,435	28.7
Total	83,788	83,333	0.5
Customers served at year-end *(in thousands)*	1,954	1,919	1.8
Peak-hour demand *(in megawatts)*	14,294	14,930	(4.3)
Capitalization Ratios *(percent)*:			
Common stock equity	53.9	52.5	
Preferred stock	0.2	0.2	
Company obligated mandatorily redeemable preferred securities	9.6	9.7	
Long-term debt	36.3	37.6	
Return on Average Common Equity *(percent)*	14.12	13.66	
Ratio of Earnings to Fixed Charges *(times)*	4.79	4.14	

2001 was an excellent year for Georgia Power in terms of financial and operational performance.

Georgia Power's earnings for 2001 totaled $610 million, a $51 million, or 9 percent increase, from 2000. These earnings were achieved despite a mild summer that resulted in a 2.5 percent overall decrease in sales of electricity to retail customers. Lower financing costs and non-operating expenses, a lower effective tax rate and continued control of operating expenses allowed us to increase earnings, despite the unfavorable weather. We earned a 14.12 percent return on average common equity during 2001.

The company prospered in 2001 because we were effective at managing the fundamentals of our business – generating and supplying power to almost 2 million customers. Our power plants posted their best reliability records ever during the summer demand. Plant Scherer Unit 1 set a record for a Southern Company coal-fired plant by running 404 continuous days without an outage. Likewise, we exceeded targets for transmission reliability, while also posting significant improvements in the duration and frequency of outages experienced by customers. We also embarked on the largest transmission line upgrade and construction program in years, and made great strides in our efforts to install new environmental controls at some of our biggest plants. The controls will help the state comply with federally mandated ozone standards.

To keep up with continuing growth in our market, we made great progress on new combined-cycle construction projects – two units totaling 1,132 megawatts at Plant Wansley and two units totaling 1,181-megawatts at Plant Goat Rock near Columbus. Both projects are natural gas-fired and will begin commercial operation before summer.

One of our major accomplishments in 2001 was securing another three-year rate plan from the Georgia Public Service Commission. We agreed to a $118 million rate reduction that will provide rate certainty and financial predictability for all parties. The agreement allows earnings on a range of retail average common equity of 10 percent to 12.95 percent and preserves a sharing mechanism between customers and the company if earnings exceed the upper end of the return range. I'm confident that with ongoing aggressive management of our business, and a possible return to more normal weather, we will continue to achieve our earnings objectives.

Reaffirming our commitment to being a Citizen Wherever We Serve, Georgia Power's community and economic development organization was again ranked one of the best in the world by *Site Selection* magazine. Our efforts were credited with helping to bring more than $761 million in new capital investment projects and more than 10,200 new jobs to Georgia in 2001.

For the fourth consecutive year, Georgia Power and its other Southern Company subsidiaries commanded many of the top slots for overall customer satisfaction in a survey of the 70 largest utilities in the nation. Georgia Power ranked first in several categories, including customer loyalty. Southern Company also ranked highest in overall customer satisfaction for electric service to midsize business customers in a survey by J.D. Power and Associates.

The company also introduced several new products and services designed to help customers better manage their energy needs. E-bill, an online bill and delivery payment system, began operations in January and by October had already surpassed its original growth targets. Later in the year, we introduced Premium Surge Protection to protect phones, computers, televisions and other appliances from damaging lightning surges, as well as a Daily Energy Credit that allows large commercial and industrial customers to earn financial rewards by reducing their electricity use during peak demand periods.

We are already dealing with the challenges of 2002. It is an exciting time for our company, and I'm pleased to have the privilege of representing some of the best employees in the industry. We remain committed to excellence in service, reliability, value and stewardship while building our corporate reputation, market share and profitability.

Sincerely,

David M. Ratcliffe

David Ratcliffe
March 22, 2002

The management of Georgia Power Company has prepared this annual report and is responsible for the financial statements and related information. These statements were prepared in accordance with accounting principles generally accepted in the United States and necessarily include amounts that are based on the best estimates and judgments of management. Financial information throughout this annual report is consistent with the financial statements.

The Company maintains a system of internal accounting controls to provide reasonable assurance that assets are safeguarded and that the accounting records reflect only authorized transactions of the Company. Limitations exist in any system of internal controls based upon the recognition that the cost of the system should not exceed its benefits. The Company believes that its system of internal accounting controls maintains an appropriate cost/benefit relationship.

The Company's system of internal accounting controls is evaluated on an ongoing basis by the Company's internal audit staff. The Company's independent public accountants also consider certain elements of the internal control system in order to determine their auditing procedures for the purpose of expressing an opinion on the financial statements.

The audit committee of the board of directors, which is composed of three independent directors, provides a broad overview of management's financial reporting and control functions. At least three times a year this committee meets with management, the internal auditors, and the independent public accountants to ensure that these groups are fulfilling their obligations and to discuss auditing, internal control and financial reporting matters. The internal auditors and the independent public accountants have access to the members of the audit committee at any time.

Management believes that its policies and procedures provide reasonable assurance that the Company's operations are conducted with a high standard of business ethics.

In management's opinion, the financial statements present fairly, in all material respects, the financial position, results of operations and cash flows of Georgia Power Company in conformity with accounting principles generally accepted in the United States.

David M. Ratcliffe
President and Chief Executive Officer

Thomas A. Fanning
Executive Vice President, Treasurer
and Chief Financial Officer
February 13, 2002

To Georgia Power Company:

We have audited the accompanying balance sheets and statements of capitalization of Georgia Power Company (a Georgia corporation and a wholly owned subsidiary of Southern Company) as of December 31, 2001 and 2000, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. 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 (pages 16-36) referred to above present fairly, in all material respects, the financial position of Georgia Power Company as of December 31, 2001 and 2000, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As explained in Note 1 to the financial statements, effective January 1, 2001, Georgia Power Company changed its method of accounting for derivative instruments and hedging activities.

Arthur Andersen LLP

Atlanta, Georgia
February 13, 2002

RESULTS OF OPERATIONS

Earnings

Georgia Power Company's 2001 earnings totaled $610 million, representing a $51 million (9.1 percent) increase over 2000. Although operating income is lower due to the impact of mild weather on retail revenues, overall net income improved due to lower financing costs and non-operating expenses and a lower effective tax rate resulting from various factors including property donations and positive resolution of outstanding tax issues. The Company's 2000 earnings totaled $559 million, representing an $18 million (3.3 percent) increase over 1999. This earnings increase was primarily due to higher retail and wholesale sales and continued control of operating expenses, partially offset by additional accelerated amortization of regulatory assets allowed under the second year of a Georgia Public Service Commission (GPSC) three-year retail rate order.

Revenues

Operating revenues in 2001 and the amount of change from the prior year are as follows:

	Amount 2001	Increase (Decrease) From Prior Year 2001	2000
		(in millions)	
Retail -			
Base revenues	$3,102	$(17)	$ 84
Fuel cost recovery	1,247	49	183
Total retail	4,349	32	267
Sales for resale -			
Non-affiliates	366	68	88
Affiliates	100	4	20
Total sales for resale	466	72	108
Other operating revenues	151	(9)	39
Total operating revenues	$4,966	$95	$414
Percent change		2.0%	9.3%

Retail base revenues of $3.1 billion in 2001 decreased $17 million (0.5 percent) from 2000 primarily due to a 2.5 percent decrease in retail sales from the prior year. Milder-than-normal weather and a slowdown in the economy contributed to the decline in such sales. Retail base revenues of $3.1 billion in 2000 increased $84 million (2.8 percent) from 1999 primarily due to a 4.9 percent increase in sales. Under the prior GPSC retail rate order, the Company recorded $44 million of revenue subject to refund for estimated earnings above 12.5 percent retail return on common equity in 2000. These refunds were made to customers in 2001. See Note 3 to the financial statements under "Retail Rate Orders" for additional information.

Electric rates include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. Under these fuel cost recovery provisions, fuel revenues generally equal fuel expenses -- including the fuel component of purchased energy -- and do not affect net income. However, cash flow is affected by the untimely recovery of these receivables. As of December 31, 2001, the Company had $162 million in underrecovered fuel costs. The Company is currently collecting these underrecovered fuel costs under a GPSC rate order issued on May 24, 2001. The fuel cost recovery rate was increased effective June 2001 to allow for a 24-month recovery of the deferred underrecovered fuel costs.

Wholesale revenues from sales to non-affiliated utilities increased in 2001 and 2000 as follows:

	2001	2000	1999
		(in millions)	
Long-term contracts	$ 61	$ 55	$ 55
Other sales	305	243	155
Total	$366	$298	$210

Revenues from long-term contracts increased slightly in 2001 due to increased energy sales while remaining constant in 2000. See Note 7 to the financial statements for further information regarding these sales. Revenues from other non-affiliated sales increased $62 million (25.5 percent) primarily due to increases in off-system sale transactions that were generally offset by corresponding purchase transactions. These transactions had no significant effect on income.

Revenues from sales to affiliated companies within the Southern electric system, as well as purchases of energy, will vary from year to year depending on demand and the availability and cost of generating resources at each company. These transactions do not have a significant impact on earnings.

Other operating revenues in 2001 decreased $9 million (5.3 percent) primarily due to lower gains on the sale of generating plant emission allowances, partially offset by increased revenues from the transmission of electricity and from the rental of electric equipment and property. Other operating revenues in 2000 increased $39 million (33 percent) primarily due to increased revenues from the transmission of electricity and gains on the sale of generating plant emission allowances. Under a GPSC order, $28 million of the gains on emission allowance sales in 2000 were used to reduce recoverable fuel costs and, as such, did not affect earnings.

Kilowatt-hour (KWH) sales for 2001 and the percent change by year were as follows:

	2001 KWH (in billions)	Percent Change 2001	Percent Change 2000
Residential	20.1	(2.8)%	6.6%
Commercial	26.5	3.4	8.1
Industrial	25.4	(8.0)	0.9
Other	0.6	2.5	3.2
Total retail	72.6	(2.5)	4.9
Sales for resale -			
Non-affiliates	8.1	25.5	27.7
Affiliates	3.1	28.7	35.6
Total sales for resale	11.2	26.3	29.8
Total sales	83.8	0.5	7.1

Residential sales decreased 2.8 percent due to milder-than-normal weather. Commercial sales increased 3.4 percent due to a 2.8 percent increase in customers, while industrial sales decreased 8.0 percent due to an economic slowdown. Residential and commercial sales increased 6.6 percent and 8.1 percent, respectively, in 2000 due to warmer summer temperatures and colder winter weather. Strong regional economic growth was also a factor in the increase in commercial sales. Industrial sales remained fairly constant.

Expenses

Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by system load, the unit cost of fuel consumed, and the availability of hydro and nuclear generating units. The amount and sources of generation and the average cost of fuel per net KWH generated were as follows:

	2001	2000	1999
Total generation (billions of KWH)	68.9	73.6	69.3
Sources of generation (percent) --			
Coal	74.9	75.8	75.5
Nuclear	23.2	21.2	21.6
Hydro	1.4	0.8	1.0
Oil and gas	0.5	2.2	1.9
Average cost of fuel per net KWH generated (cents) --	1.38	1.39	1.34

Fuel expense decreased 7.7 percent due to a decrease in generation because of lower energy demands and a slightly lower average cost of fuel. Fuel expense increased 10.7 percent in 2000 due to an increase in generation to meet higher energy demands, a decrease in generation from hydro plants, and a higher average cost of fuel.

Purchased power expense increased $175 million (29.4 percent) in 2001 primarily due to an increase in off-system purchases used to meet off-system sales commitments. These transactions had no significant effect on earnings. Purchased power expense in 2000 increased $206 million (53 percent) over the prior year due to higher retail energy demands and off-system purchase transactions used to meet off-system sales transactions.

In 2001, other operation and maintenance expenses increased $41 million (3.4%) due to additional severance costs, increased scheduled generating plant maintenance, and higher uncollectible account expense. Other operation and maintenance expenses in 2000 increased slightly over those in 1999. Increased line maintenance, customer assistance and sales expense, and severance costs were partially offset by decreased generating plant maintenance and decreased employee benefit provisions.

Depreciation and amortization decreased $19 million in 2001 primarily due to lower accelerated amortization under the third year of a GPSC retail rate order. Depreciation and amortization increased $66 million in 2000 primarily due to $50 million of additional accelerated amortization of regulatory assets required under the second year of the GPSC retail rate order and increased plant in service.

Other, net increased in 2001 due to gains realized on sales of assets and a decrease in charitable contributions. Other, net decreased in 2000 due to an increase in charitable contributions.

Interest expense, net decreased in 2001 primarily due to lower interest rates that offset new financing costs. Interest expense, net increased in 2000 due to the issuance of additional senior notes during 2000. The Company refinanced or retired $775 million and $179 million of securities in 2001 and 2000, respectively. Distributions on preferred securities of subsidiary companies remained unchanged in 2001 and decreased $7 million in 2000 due to the redemption of $100 million of preferred securities in December 1999.

Effects of Inflation

The Company is subject to rate regulation and income tax laws that are based on the recovery of historical costs. Therefore, inflation creates an economic loss because the Company is recovering its costs of investments in dollars that have less purchasing power. While the inflation rate has been relatively low in recent years, it continues to have an adverse effect on the Company because of the large investment in utility plants with long economic lives. Conventional accounting for historical cost does not recognize this economic loss nor the partially offsetting gain that arises through financing facilities with fixed-money obligations such as long-term debt and preferred securities. Any recognition of inflation by regulatory authorities is reflected in the rate of return allowed.

FUTURE EARNINGS POTENTIAL

General

The results of operations for the past three years are not necessarily indicative of future earnings. The level of future earnings depends on numerous factors including regulatory matters and energy sales.

Growth in energy sales is subject to a number of factors which traditionally have included changes in contracts with neighboring utilities, energy conservation practiced by customers, the elasticity of demand, weather, competition, initiatives to increase sales to existing customers, and the rate of economic growth in the Company's service area.

In accordance with Financial Accounting Standards Board (FASB) Statement No. 87, Employers' Accounting for Pensions, the Company recorded non-cash income of approximately $60 million in 2001. Future pension income is dependent on several factors including trust earnings and changes to the plan. For the Company, pension income is a component of the regulated rates and does not have a significant effect on net income. For additional information, see Note 2 to the financial statements.

The Company currently operates as a vertically integrated utility providing electricity to customers within its traditional service area located in the State of Georgia. Prices for electricity provided by the Company to retail customers are set by the GPSC under cost-based regulatory principles.

On December 20, 2001, the GPSC approved a new three-year retail rate order for the Company ending December 31, 2004. Under the terms of the order, earnings will be evaluated annually against a retail return on common equity range of 10 percent to 12.95 percent. Two-thirds of any earnings above the 12.95 percent return will be applied to rate refunds, with the remaining one-third retained by the Company. Retail rates were decreased by $118 million effective January 1, 2002. Pursuant to a previous three-year accounting order, the Company recorded $336 million of accelerated cost amortization and interest thereon which has been credited to a regulatory liability account as mandated by the GPSC. Under the new rate order, the accelerated amortization and the interest will be amortized equally over three years as a credit to expense beginning in 2002. The Company will not file for a general base rate increase unless its projected retail return on common equity falls below 10 percent. Georgia Power is required to file a general rate case on July 1, 2004, in response to which the GPSC would be expected to determine whether the rate order should be continued, modified, or discontinued. See Note 3 to the financial statements under "Retail Rate Orders" for additional information.

The Company has entered into power purchase agreements which will result in higher capacity and operating and maintenance payments in future years. Under the new retail rate order, these costs will be reflected in rates evenly over the next three years. See Note 4 to the financial statements under "Purchased Power Commitments" for additional information.

Georgia Power had three new generation projects under construction during 2001. They included two units at Plant Dahlberg, a ten-unit, 800 megawatt combustion turbine facility; two combined cycle units totaling 1,132 megawatts at Plant Wansley; and Plant Goat Rock, a two-unit, 1,181 megawatt combined cycle facility. All three of these projects have been transferred to Southern Power Company, a new Southern Company subsidiary formed in 2001 to construct, own, and manage wholesale generating assets in the Southeast. The ten Dahlberg units and two Goat Rock units were transferred in 2001 and the transfer of the two Wansley units was completed in January 2002.

The Company is involved in various matters being litigated. See Note 3 to the financial statements for information regarding material issues that could possibly affect future earnings.

Compliance costs related to current and future environmental laws, regulations, and litigation could affect earnings if such costs are not fully recovered. See "Environmental Issues" for further discussion of these matters.

Industry Restructuring

The electric utility industry in the United States is continuing to evolve as a result of regulatory and competitive factors. Among the primary agents of change has been the Energy Policy Act of 1992 (Energy Act). The Energy Act allows independent power producers (IPPs) to access a utility's transmission network in order to sell electricity to other utilities. This enhances the incentive for IPPs to build cogeneration plants for a utility's large industrial and commercial customers and sell energy generation to other utilities. Also, electricity sales for resale rates are affected by wholesale transmission access and numerous potential new energy suppliers, including power marketers and brokers.

Although the Energy Act does not permit retail customer access, it has been a major catalyst for recent restructuring and consolidations taking place within the utility industry. Numerous federal and state initiatives are in varying stages that promote wholesale and retail competition. Among other things, these initiatives allow customers to choose their electricity provider. Some states have approved initiatives that result in a separation of the ownership and/or operation of generating facilities from the ownership and/or operation of transmission and distribution facilities. While restructuring and competition initiatives have been discussed in Georgia, none have been enacted. Enactment would require numerous issues to be resolved, including significant ones relating to recovery of any stranded investments, full cost recovery of energy produced, and other issues related to the energy crisis that occurred in California. As a result of that crisis, many states have either discontinued or delayed implementation of initiatives involving retail deregulation. The Company does compete with other electric suppliers within the state. In Georgia, most new retail customers with at least 900 kilowatts of connected load may choose their electricity supplier.

In December 1999, the Federal Energy Regulatory Commission (FERC) issued its final rule on Regional Transmission Organizations (RTOs). The order encouraged utilities owning transmission systems to form RTOs on a voluntary basis. Southern Company has submitted a series of status reports informing the FERC of progress toward the development of a Southeastern RTO. In these status reports, Southern Company explained that it is developing an RTO known as SeTrans with a number of non-jurisdictional cooperative and public power entities. Recently, Entergy Corporation and Cleco Power joined the SeTrans development process. In January 2002, the sponsors of SeTrans held a public meeting to form a Stakeholder Advisory Committee, which will participate in the development of the RTO. Southern Company continues to work with the other sponsors to develop the SeTrans RTO. The creation of SeTrans is not expected to have a material impact on Georgia Power's financial statements. The outcome of this matter cannot now be determined.

Accounting Policies

Critical Policy

Georgia Power's significant accounting policies are described in Note 1 to the financial statements. The Company's most critical accounting policy involves rate regulation. The Company is subject to the provisions of FASB Statement No. 71, Accounting for the Effects of Certain Types of Regulation. In the event that a portion of the Company's operations is no longer subject to these provisions, the Company would be required to write off related regulatory assets and liabilities that are not specifically recoverable, and determine if any other assets, including plant, have been impaired. See Note 1 to the financial statements under "Regulatory Assets and Liabilities" for additional information.

New Accounting Standards

Effective January 2001, Georgia Power adopted FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended. Statement No. 133 establishes accounting and reporting standards for derivative instruments and for hedging activities. This statement requires that certain derivative instruments be recorded in the balance sheet as either an asset or liability measured at fair value, and that changes in the fair value be recognized currently in earnings unless specific hedge accounting criteria are met. See Note 1 to the financial statements under "Financial Instruments" for additional information. The impact on net income in 2001 was not material. An additional interpretation of Statement No. 133 will result in a change -- effective April 1, 2002 -- in accounting for certain contracts related to fuel supplies that contain quantity options. These contracts will be accounted for as derivatives and marked to market. However, due to the existence of specific cost-based fuel recovery clauses for the Company, this change is not expected to have a material impact on net income.

In June 2001, the FASB issued Statement No. 142, Goodwill and Other Intangible Assets, which establishes new accounting and reporting standards for acquired goodwill and other intangible assets and supersedes Accounting Principles Board Opinion No. 17. Statement No. 142 addresses how intangible assets that are acquired individually or with a group of other assets (but not those acquired in a business combination) should be accounted for upon acquisition and on an ongoing basis. Goodwill and intangible assets that have indefinite useful lives will not be amortized but rather will be tested at least annually for impairment. Intangible assets that have finite useful lives will continue to be amortized over their useful lives, which are no longer limited to 40 years. The Company adopted Statement No. 142 effective January 1, 2002 with no material impact on the Company's financial statements.

Also, in June 2001, the FASB issued Statement No. 143, Asset Retirement Obligations, which establishes new accounting and reporting standards for legal obligations associated with retiring assets, including decommissioning nuclear plants. The liability for an asset's future retirement must be recorded in the period in which the liability is incurred. The cost must be capitalized as part of the related long-lived asset and depreciated over the asset's useful life. Changes in the liability resulting from the passage of time will be recognized as operating expenses. Statement No. 143 must be adopted by January 1, 2003. The Company has not yet quantified the impact of adopting Statement No. 143 on its financial statements.

FINANCIAL CONDITION

Plant Additions

In 2001, gross utility plant additions were $1.4 billion. These additions were primarily related to transmission and distribution facilities, the purchase of nuclear fuel, and the construction of additional combustion turbine and combined cycle units. The funds needed for gross property additions are currently provided from operations, short-term and long-term debt, and capital contributions from Southern Company. The Statements of Cash Flows provide additional details.

Credit Rating Risk

The Company does not have any credit agreements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain physical electricity sale contracts that could require collateral -- but not termination -- in the event of a credit rating change to below investment grade. At December 31, 2001, the maximum potential collateral requirements were approximately $112 million.

Exposure to Market Risks

The Company is exposed to market risks, including changes in interest rates, currency exchange rates, and certain commodity prices. To manage the volatility attributable to these exposures, the Company nets the exposures to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and hedging practices. Company policy is that derivatives are to be used primarily for hedging purposes. Derivative positions are monitored using techniques that include market valuation and sensitivity analysis.

The Company's market risk exposures relative to interest rate changes have not changed materially compared to the previous reporting period. In addition, the Company is not aware of any facts or circumstances that would significantly affect such exposures in the near term.

If the Company sustained a 100 basis point change in interest rates for all variable rate long-term debt, the change would affect annualized interest expense by approximately $13 million at December 31, 2001. Based on the Company's overall interest rate exposure at December 31, 2001, including derivative and other interest rate sensitive instruments, a near-term 100 basis point change in interest rates would not materially affect the Company's financial statements.

Due to cost-based rate regulations, the Company has limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To mitigate residual risks relative to movements in electricity prices, the Company entered into fixed price contracts for the purchase and sale of electricity through the wholesale electricity market and to a lesser extent similar contracts for gas purchases. Realized gains and losses are recognized in the Statements of Income as incurred. At December 31, 2001, exposure from these activities was not material to the Company's financial statements. Fair value of changes in energy trading contracts and year-end valuations are as follows:

	Changes During the Year
	Fair Value
	(in millions)
Contracts beginning of year	$0.9
Contracts realized or settled	(0.6)
New contracts at inception	-
Changes in valuation techniques	-
Current period changes	0.1
Contracts end of year	$0.4

All of these contracts are actively quoted and mature within one year. For additional information, see Note 1 to the financial statements under "Financial Instruments."

Financing Activities

In 2001, the Company's financing costs decreased due to lower interest rates despite the issuance of new debt during the year. New issues during 1999 through 2001 totaled $1.9 billion and retirement or repayment of higher-cost securities totaled $1.7 billion.

The proceeds from assets transferred to Southern Power were used to reduce short-term debt and return capital to the Southern Company that was used during the construction of these projects.

Composite financing rates for long-term debt, preferred stock, and preferred securities for the years 1999 through 2001, as of year-end, were as follows:

	2001	2000	1999
Composite interest rate on long-term debt	4.26%	5.90%	5.48%
Composite preferred stock dividend rate	4.60	4.60	4.60
Composite preferred securities dividend rate	7.49	7.49	7.49

Liquidity and Capital Requirements

Cash provided from operations remained constant in 2001.

The Company estimates that construction expenditures for the years 2002 through 2004 will total $1.0 billion, $0.8 billion, and $0.8 billion, respectively. Investments primarily in additional transmission and distribution facilities and equipment to comply with environmental requirements are planned.

Cash requirements for redemptions announced and maturities of long-term debt are expected to total $666 million during 2002 through 2004.

As a result of requirements by the Nuclear Regulatory Commission, the Company has established external trust funds for the purpose of funding nuclear decommissioning costs. The amount to be funded under the new GPSC rate order is $8.7 million each year in 2002, 2003, and 2004. For additional information concerning nuclear decommissioning costs, see Note 1 to the financial statements under "Depreciation and Nuclear Decommissioning."

Sources of Capital

The Company expects to meet future capital requirements primarily using funds generated from operations and equity funds from Southern Company and by the issuance of new debt and equity securities, term loans, and short-term borrowings. The Company plans to request new financing authority from the GPSC in early 2002 to allow for the issuance of new long-term securities. To meet short-term cash needs and contingencies, the Company had approximately $1.8 billion of unused credit arrangements with banks at the beginning of 2002. See

Note 9 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other Southern Company operating companies. At December 31, 2001, the Company had outstanding $707.6 million of commercial paper.

Recently, the Company has relied on the issuance of unsecured debt and trust preferred securities, in addition to unsecured pollution control bonds issued for its benefit by public authorities, to meet its long-term external financing requirements. In years past, the Company issued first mortgage bonds, mortgage backed pollution control bonds and preferred stock to fund its external requirements. The amount outstanding of these securities has been steadily declining during the last four years.

Other Capital Requirements

In addition to the funds needed for the construction program, approximately $666 million will be required by the end of 2004 for maturities of long-term debt. Also, the Company will continue to retire higher-cost debt and preferred securities and replace these obligations with lower-cost capital if market conditions permit.

These capital requirements, lease obligations, and purchase commitments -- discussed in Notes 4 and 9 to the financial statements -- are as follows:

	2002	2003	2004
	(in millions)		
Bonds –			
First mortgage	$ 2	$ -	$ -
Pollution control	8	-	-
Notes	300	350	-
Leases –			
Capital	2	2	2
Operating	15	15	15
Purchase commitments			
Fuel	1,234	1,115	617
Purchased power	163	223	278

At the beginning of 2002, Georgia Power had not used any of its available credit arrangements. Credit arrangements are as follows:

		Expires	
Total	Unused	2002	2003 & beyond
(in millions)			
$1,765	$1,765	$1,265	$500

ENVIRONMENTAL ISSUES

Clean Air Legislation

In November 1990, the Clean Air Act Amendments of 1990 (Clean Air Act) were signed into law. Title IV of the Clean Air Act -- the acid rain compliance provision of the law -- significantly affected Southern Company's subsidiaries, including the Company. Reductions in sulfur dioxide and nitrogen oxide emissions from fossil-fired generating plants were required in two phases. Phase I compliance began in 1995.

Southern Company's subsidiaries, including the Company, achieved Phase I compliance at the affected units by primarily switching to low-sulfur coal and with some equipment upgrades. Construction expenditures for the Company's Phase I compliance totaled approximately $167 million.

Phase II sulfur dioxide compliance was required in 2000. Southern Company's subsidiaries, including the Company, used emission allowances and fuel switching to comply with Phase II requirements. Also, equipment to control nitrogen oxide emissions was installed on additional system fossil-fired units as necessary to meet Phase II limits and ozone non-attainment requirements for metropolitan Atlanta through 2000. Compliance for Phase II and initial ozone non-attainment requirements increased total construction expenditures for the Company through 2000 by approximately $39 million.

In 2000, the State of Georgia established new emission limits designed to help bring the Atlanta area into compliance with the national one-hour standard for ground-level ozone. The limits include new emission standards for seven of the Company's generating stations and will go into effect in May 2003. Construction expenditures for the Company's compliance with these new rules are currently estimated at approximately $699 million with a total of $345 million remaining to be spent.

A significant portion of costs related to the acid rain and ozone non-attainment provisions of the Clean Air Act is expected to be recovered through existing ratemaking provisions. However, there can be no assurance that all Clean Air Act costs will be recovered.

In July 1997, the Environmental Protection Agency (EPA) revised the national ambient air quality standards for ozone and particulate matter. This revision made the standards significantly more stringent. In the subsequent litigation of these standards, the U.S. Supreme Court found the EPA's implementation program for the new ozone standard unlawful and remanded it to the EPA. In addition, the Federal District of Columbia Circuit Court of Appeals is considering other legal challenges to these standards. If the standards are eventually upheld, implementation could be required by 2007 to 2010.

In September 1998, the EPA issued regional nitrogen oxide reduction rules to the states for implementation. The final rule affects 21 states including Georgia. Compliance is required by May 31, 2004. The EPA proposed rules for Georgia on February 13, 2002. The EPA's proposal includes a May 1, 2005 implementation date for Georgia. The Company plans to demonstrate compliance based largely on NOx controls already installed to meet the Atlanta non-attainment requirements, coupled with the purchase of NOx credits within a NOx trading market.

In December 2000, having completed its utility study for mercury and other hazardous air pollutants (HAPS), the EPA issued a determination that an emission control program for mercury and, perhaps, other HAPS is warranted. The program is to be developed under the Maximum Achievable Control Technology provisions of the Clean Air Act, and regulations are scheduled to be finalized by the end of 2004 with implementation to take place around 2007. In January 2001, the EPA proposed guidance for the determination of Best Available Retrofit Technology (BART) emission controls under the Regional Haze Regulations. Installation of BART controls is expected to take place around 2010. Litigation of the Regional Haze Regulations, including the BART provisions, is ongoing in the Federal District of Columbia Circuit Court of Appeals. A court decision is expected in mid-2002.

Implementation of the final state rules for these initiatives could require substantial further reductions in nitrogen oxide and sulfur dioxide and reductions in mercury and other HAPS emissions from fossil-fired generating facilities and other industries in these states. Additional compliance costs and capital expenditures resulting from the implementation of these rules and standards cannot be determined until the results of legal challenges are known, and the states have adopted their final rules.

In October 1997, the EPA issued regulations setting forth requirements for Compliance Assurance Monitoring (CAM) in state and federal operating permit programs. These regulations were amended by the EPA in March 2001 in response to a court order resolving challenges to the rules brought by environmental groups and industry. Generally, this rule affects the operation and maintenance of electrostatic precipitators and could involve significant additional ongoing expense.

The EPA and state environmental regulatory agencies are reviewing and evaluating various matters including: control strategies to reduce regional haze; limits on pollutant discharges to impaired waters; cooling water intake restrictions; and hazardous waste disposal requirements. The impact of any new standards will depend on the development and implementation of applicable regulations.

Environmental Protection Agency Litigation

On November 3, 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia. The complaint alleges violations of the prevention of significant deterioration and new source review provisions of the Clean Air Act with respect to coal-fired generating facilities at the Company's Bowen and Scherer plants. The civil action requests penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. The EPA concurrently issued a notice of violation to the Company relating to these two plants. In early 2000, the EPA filed a motion to amend its complaint to add the violations alleged in its notice of violation. The complaint and the notice of violation are similar to those brought against and issued to several other electric utilities. The complaint and the notice of violation allege that the Company failed to secure necessary permits or install additional pollution control equipment when performing maintenance and construction at coal burning plants constructed or under construction prior to 1978. The Company believes that it complied with applicable laws and the EPA's regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes civil penalties of up to $27,500 per day per violation at each generating unit. Prior to January 30, 1997, the penalty was $25,000 per day.

The case against the Company has been stayed since the spring of 2001 pending a ruling by the federal Court of Appeals for the Eleventh Circuit in the appeal of a very similar Clean Air Act / New Source Review enforcement action brought by EPA against the Tennessee Valley Authority (TVA). The TVA case involves many of the same legal issues raised by the actions against the Company. Because the outcome of the TVA case could have a significant adverse impact on Georgia Power, the Company is a party to that case as well. The federal court in Georgia is currently considering a motion by the EPA to reopen the case. The Company has opposed that motion. An adverse outcome of this matter could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

Other Environmental Issues

The Company must comply with other environmental laws and regulations that cover the handling and disposal of hazardous waste. Under these various laws and regulations, the Company could incur costs to clean up properties currently or previously owned. The Company conducts studies to determine the extent of any required clean-up and has recognized in the financial statements costs to clean up known sites. These costs for the Company amounted to $0.6 million in 2001 and $4 million in both 2000 and 1999. Additional sites may require environmental remediation for which the Company may be liable for all or a portion of required clean-up costs. See Note 3 to the financial statements under "Other Environmental Contingencies" for information regarding the Company's potentially responsible party status at sites in Georgia.

Several major pieces of environmental legislation are periodically considered for reauthorization or amendment by Congress. These include: the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; and the Endangered Species Act. Changes to these laws could affect many areas of the Company's operations. The full impact of any such changes cannot be determined at this time.

Compliance with possible additional legislation related to global climate change, electromagnetic fields, and other environmental and health concerns could significantly affect the Company. The impact of new legislation -- if any -- will depend on the subsequent development and implementation of applicable regulations. In addition, the potential exists for liability as the result of lawsuits alleging damages caused by electromagnetic fields.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

The Company's 2001 Annual Report includes forward-looking statements in addition to historical information. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "predicts," "projects," "potential" or "continue" or the negative of these terms or other comparable terminology. The Company cautions that there are various important factors that could cause actual results to differ materially from those indicated in the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include the impact of recent and future federal and state regulatory change, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry and also changes in environmental and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations; current and future litigation, including the pending EPA civil action and the race discrimination litigation against the Company; the effect, extent, and timing of the entry of additional competition in the markets in which the Company operates; the impact of fluctuations in commodity prices, interest rates, and customer demand; state and federal rate regulations; political, legal, and economic conditions and developments in the United States; the effects of, and changes in economic conditions in the areas in which the Company operates; internal restructuring or other restructuring options that may be pursued by the Company; potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial; the direct or indirect effects on the Company's business resulting from the terrorist incidents on September 11, 2001, or any similar such incidents or responses to such incidents; financial market conditions and the results of financing efforts; the ability of the Company to obtain additional generating capacity at competitive prices; weather and other natural phenomena; and other factors discussed elsewhere herein and in other reports (including Form 10-K) filed from time to time by the Company with the Securities and Exchange Commission.

STATEMENTS OF INCOME

For the Years Ended December 31, 2001, 2000, and 1999
Georgia Power Company 2001 Annual Report

	2001	2000	1999
		(in thousands)	
Operating Revenues:			
Retail sales	$4,349,312	$4,317,338	$4,050,088
Sales for resale --			
Non-affiliates	366,085	297,643	210,104
Affiliates	99,411	96,150	76,426
Other revenues	150,986	159,487	120,057
Total operating revenues	4,965,794	4,870,618	4,456,675
Operating Expenses:			
Operation --			
Fuel	939,092	1,017,878	919,876
Purchased power --			
Non-affiliates	442,196	356,189	214,573
Affiliates	329,232	239,815	174,989
Other	810,043	795,458	784,359
Maintenance	430,413	404,189	411,983
Depreciation and amortization	600,631	619,094	552,966
Taxes other than income taxes	202,483	204,527	202,853
Total operating expenses	3,754,090	3,637,150	3,261,599
Operating Income	1,211,704	1,233,468	1,195,076
Other Income (Expense):			
Interest income	4,264	2,629	5,583
Equity in earnings of unconsolidated subsidiaries	4,178	3,051	2,721
Other, net	(2,816)	(50,495)	(47,986)
Earnings Before Interest and Income Taxes	1,217,330	1,188,653	1,155,394
Interest Charges and Other:			
Interest expense, net	183,879	208,868	194,869
Distributions on preferred securities of subsidiaries	59,104	59,104	65,774
Total interest charges and other, net	242,983	267,972	260,643
Earnings Before Income Taxes	974,347	920,681	894,751
Income taxes	363,599	360,587	351,639
Net Income Before Cumulative Effect of Accounting Change	610,748	560,094	543,112
Cumulative effect of accounting change -- less income taxes of $162 thousand	257	-	-
Net Income	611,005	560,094	543,112
Dividends on Preferred Stock	670	674	1,729
Net Income After Dividends on Preferred Stock	$ 610,335	$ 559,420	$ 541,383

The accompanying notes are an integral part of these statements.

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2001, 2000, and 1999
Georgia Power Company 2001 Annual Report

	2001	2000	1999
		(in thousands)	
Operating Activities:			
Net income	$ 611,005	$ 560,094	$ 543,112
Adjustments to reconcile net income to net cash provided from operating activities --			
Depreciation and amortization	697,143	712,960	663,878
Deferred income taxes and investment tax credits, net	(48,329)	(28,961)	(34,930)
Other, net	(92,403)	(51,501)	(42,179)
Changes in certain current assets and liabilities --			
Receivables, net	60,914	(108,621)	21,665
Fossil fuel stock	(103,296)	26,835	(22,165)
Materials and supplies	(15,628)	(9,715)	(10,417)
Accounts payables	(15,406)	64,412	13,095
Energy cost recovery, retail	(29,839)	(95,235)	(26,862)
Other	(2,999)	(9,092)	90,788
Net cash provided from operating activities	1,061,162	1,061,176	1,195,985
Investing Activities:			
Gross property additions	(1,389,751)	(1,078,163)	(790,464)
Sales of property	534,760	-	-
Other	(4,774)	(5,450)	(27,454)
Net cash used for investing activities	(859,765)	(1,083,613)	(817,918)
Financing Activities:			
Increase in notes payable, net	43,698	67,598	295,389
Proceeds --			
Senior notes	600,000	300,000	100,000
Pollution control bonds	404,535	78,725	238,000
Preferred securities	-	-	200,000
Capital contributions from parent company	225,060	301,514	155,777
Retirements --			
First mortgage bonds	(390,140)	(100,000)	(404,000)
Pollution control bonds	(385,035)	(78,725)	(235,000)
Preferred securities	-	-	(100,000)
Preferred stock	-	(383)	(36,231)
Capital distributions to parent company	(160,000)	-	-
Payment of preferred stock dividends	(578)	(751)	(984)
Payment of common stock dividends	(527,300)	(549,600)	(543,000)
Other	(17,747)	(1,231)	(29,630)
Net cash provided from (used for) financing activities	(207,507)	17,147	(359,679)
Net Change in Cash and Cash Equivalents	(6,110)	(5,290)	18,388
Cash and Cash Equivalents at Beginning of Year	29,370	34,660	16,272
Cash and Cash Equivalents at End of Year	$ 23,260	$ 29,370	$ 34,660
Supplemental Cash Flow Information:			
Cash paid during the year for --			
Interest (net of amount capitalized)	$ 234,456	$ 265,373	$ 247,050
Income taxes (net of refunds)	381,995	392,310	394,457

The accompanying notes are an integral part of these statements.

BALANCE SHEETS
At December 31, 2001 and 2000
Georgia Power Company 2001 Annual Report

Assets	2001	2000
	(in thousands)	
Current Assets:		
Cash and cash equivalents	$ 23,260	$ 29,370
Receivables --		
Customer accounts receivable	376,322	465,249
Underrecovered retail fuel clause revenue	161,462	131,623
Other accounts and notes receivable	129,073	156,143
Affiliated companies	87,786	13,312
Accumulated provision for uncollectible accounts	(8,895)	(5,100)
Fossil fuel stock, at average cost	202,759	99,463
Materials and supplies, at average cost	279,237	263,609
Other	125,246	97,515
Total current assets	1,376,250	1,251,184
Property, Plant, and Equipment:		
In service	16,886,399	16,469,706
Less accumulated provision for depreciation	7,243,209	6,914,512
	9,643,190	9,555,194
Nuclear fuel, at amortized cost	112,771	120,570
Construction work in progress (Note 4)	883,285	652,264
Total property, plant, and equipment	10,639,246	10,328,028
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries (Note 4)	35,209	29,569
Nuclear decommissioning trusts	364,180	375,666
Other	29,618	29,745
Total other property and investments	429,007	434,980
Deferred Charges and Other Assets:		
Deferred charges related to income taxes (Note 8)	543,584	565,982
Prepaid pension costs	228,259	147,271
Debt expense, being amortized	58,165	53,748
Premium on reacquired debt, being amortized	173,724	173,610
Other	117,706	120,964
Total deferred charges and other assets	1,121,438	1,061,575
Total Assets	$13,565,941	$13,075,767

The accompanying notes are an integral part of these balance sheets.

BALANCE SHEETS
At December 31, 2001 and 2000
Georgia Power Company 2001 Annual Report

Liabilities and Stockholder's Equity	2001	2000
	(in thousands)	
Current Liabilities:		
Securities due within one year (Note 9)	$ 311,620	$ 1,808
Notes payable	747,537	703,839
Accounts payable --		
Affiliated	109,591	117,168
Other	409,253	397,550
Customer deposits	83,172	78,540
Taxes accrued --		
Income taxes	35,247	5,151
Other	125,807	137,511
Interest accrued	46,942	47,244
Vacation pay accrued	41,830	38,865
Other	112,686	137,565
Total current liabilities	2,023,685	1,665,241
Long-term debt (See accompanying statements)	2,961,726	3,041,939
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes (Note 8)	2,163,959	2,182,783
Deferred credits related to income taxes (Note 8)	229,216	247,067
Accumulated deferred investment tax credits (Note 8)	337,482	352,282
Employee benefits provisions	207,795	191,587
Other	440,774	341,505
Total deferred credits and other liabilities	3,379,226	3,315,224
Company obligated mandatorily redeemable preferred securities of subsidiary trusts holding company junior subordinated notes (See accompanying statements)	789,250	789,250
Cumulative preferred stock (See accompanying statements)	14,569	14,569
Common stockholder's equity (See accompanying statements)	4,397,485	4,249,544
Total Liabilities and Stockholder's Equity	$13,565,941	$13,075,767

The accompanying notes are an integral part of these balance sheets.

STATEMENTS OF CAPITALIZATION

At December 31, 2001 and 2000

Georgia Power Company 2001 Annual Report

		2001	2000	2001	2000
		(in thousands)		*(percent of total)*	
Long-Term Debt:					
First mortgage bonds --					
Maturity	Interest Rates				
April 1, 2003	6.625%	$ -	$ 200,000		
August 1, 2003	6.35%	-	75,000		
2005	6.07%	1,860	10,000		
2008	6.875%	-	50,000		
2025	7.70%	-	57,000		
Total first mortgage bonds		1,860	392,000		
Senior notes -- (Note 9)					
Variable rate (1.98125% at 1/1/02) due February 22, 2002		300,000	300,000		
5.75% due January 31, 2003		200,000	-		
5.25% due May 8, 2003		150,000	-		
5.50% due December 1, 2005		150,000	150,000		
6.20% due February 1, 2006		150,000	-		
6.70% due March 1, 2011		100,000	-		
6.60% due December 31, 2038		200,000	200,000		
6.625% due March 31, 2039		100,000	100,000		
6.875% due December 31, 2047		145,000	145,000		
Total senior notes payable		1,495,000	895,000		
Other long-term debt -- (Note 9)					
Pollution control revenue bonds --					
Maturity	Interest Rates				
2005	5.00%	-	57,000		
2011	Variable (1.90% to 1.95% at 1/1/02)	10,450	10,450		
2012-2016	4.20% to 5.00%	164,590	-		
2018-2021	6.00% to 6.25%	7,800	23,225		
2018	Variable (2.00% at 1/1/02)	19,500	-		
2023-2025	4.90% to 6.75%	28,065	298,535		
2022-2026	Variable (1.75% to 1.95% at 1/1/02)	669,480	683,555		
2029	Variable (1.90% to 1.95% at 1/1/02)	144,700	144,700		
2030-2031	4.53% to 5.25%	137,570	78,725		
2032-2034	Variable (1.75% to 1.95% at 1/1/02)	140,000	140,000		
2032-2034	4.45% to 5.45%	371,535	238,000		
Total other long-term debt		1,693,690	1,674,190		
Capital lease obligations (Note 9)		83,371	85,179		
Unamortized debt discount, net		(575)	(2,622)		
Total long-term debt (annual interest requirement -- $139.5 million)		3,273,346	3,043,747		
Less amount due within one year (Note 9)		311,620	1,808		
Total long-term debt excluding amount due within one year		$ 2,961,726	$ 3,041,939	36.3 %	37.6 %

STATEMENTS OF CAPITALIZATION (continued)
At December 31, 2001 and 2000
Georgia Power Company 2001 Annual Report

	2001	2000	2001	2000
	(in thousands)		(percent of total)	
Company Obligated Mandatorily				
Redeemable Preferred Securities (Note 9):				
$25 liquidation value -- 6.85%	$ 200,000	$ 200,000		
$25 liquidation value -- 7.60%	175,000	175,000		
$25 liquidation value -- 7.75%	189,250	189,250		
$25 liquidation value -- 7.75%	225,000	225,000		
Total (annual distribution requirement -- $59.1 million)	789,250	789,250	9.6	9.7
Cumulative Preferred Stock, without par value:				
Authorized -- 55,000,000 shares				
Outstanding -- 145,689 shares at December 31, 2001				
Outstanding -- 145,689 shares at December 31, 2000				
$100 stated value --				
4.60%	14,569	14,569		
Total cumulative preferred stock (annual dividend requirement -- $0.7 million)	14,569	14,569	0.2	0.2
Common Stockholder's Equity:				
Common stock, without par value --				
Authorized -- 15,000,000 shares				
Outstanding -- 7,761,500 shares	344,250	344,250		
Paid-in capital	2,182,557	2,117,497		
Premium on preferred stock	40	40		
Other comprehensive income	(153)	-		
Retained earnings (Note 9)	1,870,791	1,787,757		
Total common stockholder's equity (See accompanying statements)	4,397,485	4,249,544	53.9	52.5
Total Capitalization	$ 8,163,030	$ 8,095,302	100.0 %	100.0 %

The accompanying notes are an integral part of these statements.

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

For the Years Ended December 31, 2001, 2000, and 1999

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	Common Stock	Paid-In Capital	Premium on Preferred Stock	Retained Earnings	Other Comprehensive Income (Loss)	Total
			(in thousands)			
Balance at January 1, 1999	$344,250	$1,660,206	$158	$1,779,558	$ -	$3,784,172
Net income after dividends on preferred stock	-	-	-	541,383	-	541,383
Capital contributions from parent company	-	155,777	-	-	-	155,777
Cash dividends on common stock	-	-	-	(543,000)	-	(543,000)
Preferred stock transactions, net	-	-	(118)	(4)	-	(122)
Balance at December 31, 1999	344,250	1,815,983	40	1,777,937	-	3,938,210
Net income after dividends on preferred stock	-	-	-	559,420	-	559,420
Capital contributions from parent company	-	301,514	-	-	-	301,514
Cash dividends on common stock	-	-	-	(549,600)	-	(549,600)
Balance at December 31, 2000	344,250	2,117,497	40	1,787,757	-	4,249,544
Net income after dividends on preferred stock	-	-	-	610,335	-	610,335
Capital contributions from parent company	-	225,060	-	-	-	225,060
Capital distributions to parent company		(160,000)				(160,000)
Other comprehensive income	-	-	-	-	(153)	(153)
Cash dividends on common stock	-	-	-	(527,300)	-	(527,300)
Preferred stock transactions, net	-	-	-	(1)	-	(1)
Balance at December 31, 2001	$344,250	$2,182,557	$40	$1,870,791	($153)	$4,397,485

STATEMENTS OF COMPREHENSIVE INCOME

For the Years Ended December 31, 2001, 2000, and 1999

Georgia Power Company 2001 Annual Report

	2001	2000	1999
	(in thousands)		
Net income after dividends on preferred stock	$ 610,335	$ 559,420	$ 541,383
Other comprehensive income:			
Cumulative effect of accounting change, net of tax	286	-	-
Current period changes in fair value, net of tax	(439)	-	-
Comprehensive Income	$ 610,182	$ 559,420	$ 541,383

The accompanying notes are an integral part of these statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

The Company is a wholly owned subsidiary of Southern Company, which is the parent company of five operating companies, a system service company (SCS), Southern Communications Services (Southern LINC), Southern Nuclear Operating Company (Southern Nuclear), Southern Power Company (Southern Power), and other direct and indirect subsidiaries. The operating companies --Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Savannah Electric and Power Company-- provide electric service in four southeastern states. Contracts among the operating companies -- related to jointly owned generating facilities, interconnecting transmission lines, and the exchange of electric power -- are regulated by the Federal Energy Regulatory Commission (FERC) and/or the Securities and Exchange Commission. SCS provides, at cost, specialized services to Southern Company and subsidiary companies. Southern LINC provides digital wireless communications services to the operating companies and also markets these services to the public within the Southeast. Southern Nuclear provides services to Southern Company's nuclear power plants. Southern Power was established in 2001 to construct, own, and manage Southern Company's competitive generation assets and sell electricity at market-based rates in the wholesale market.

Southern Company is registered as a holding company under the Public Utility Holding Company Act of 1935 (PUHCA). Both Southern Company and its subsidiaries are subject to the regulatory provisions of the PUHCA. The Company is also subject to regulation by the FERC and the Georgia Public Service Commission (GPSC). The Company follows accounting principles generally accepted in the United States and complies with the accounting policies and practices prescribed by the respective regulatory commissions. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires the use of estimates, and the actual results may differ from these estimates.

Certain prior years' data presented in the financial statements have been reclassified to conform with current year presentation.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at cost: general and design engineering, purchasing, accounting and statistical, finance and treasury, tax, information resources, marketing, auditing, insurance and pension, human resources, systems and procedures, and other services with respect to business and operations and power pool operations. Costs for these services amounted to \$285 million, \$269 million, and \$253 million during 2001, 2000, and 1999, respectively.

The Company has an agreement with Southern Nuclear under which the following nuclear-related services are rendered to the Company at cost: general executive and advisory services; general operations, management and technical services; administrative services including procurement, accounting and statistical, employee relations, and systems and procedures services; strategic planning and budgeting services; and other services with respect to business and operations. Costs for these services amounted to \$281 million in both 2001 and 2000 and \$270 million in 1999.

Regulatory Assets and Liabilities

The Company is subject to the provisions of Financial Accounting Standards Board (FASB) Statement No. 71, *Accounting for the Effects of Certain Types of Regulation*. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process. See Note 3 under "Retail Rate Orders" for additional information regarding the disposition of the regulatory liability for the accelerated cost recovery recorded under the retail rate order that ended December 31, 2001. Regulatory assets and (liabilities) reflected in the Company's Balance Sheets at December 31 relate to the following:

	2001	2000
	(in millions)	
Deferred income taxes	$ 544	$ 566
Deferred income tax credits	(229)	(247)
Premium on reacquired debt	174	174
Corporate building lease	54	55
Vacation pay	52	49
Postretirement benefits	28	30
Department of Energy assessments	18	21
Deferred nuclear outage costs	24	28
Accelerated cost recovery and interest	(336)	(230)
Other, net	16	23
Total	$ 345	$ 469

In the event that a portion of the Company's operations is no longer subject to the provisions of Statement No. 71, the Company would be required to write off related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets exists, including plant, and write down the assets, if impaired, to their fair value.

Revenues and Fuel Costs

The Company currently operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the state of Georgia, and to wholesale customers in the Southeast.

The Company has a diversified base of customers. No single customer or industry comprises 10 percent or more of revenues. For all periods presented, uncollectible accounts averaged less than 1 percent of revenues.

Revenues are recognized as services are rendered. Unbilled revenues are accrued at the end of each fiscal period. Fuel costs are expensed as the fuel is used. The Company's fuel cost recovery mechanism includes provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between recoverable fuel costs and amounts actually recovered in current rates.

Fuel expense includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel. Total charges for nuclear fuel included in fuel expense amounted to $75 million in each of 2001 and 2000 and $74 million in 1999. The Company has contracts with the U.S. Department of Energy (DOE) that provide for the permanent disposal of used nuclear fuel. The DOE failed to begin disposing of used nuclear fuel in January 1998 as required by the contracts, and the Company is pursuing legal remedies against the government for breach of contract. Sufficient pool storage capacity is available at Plant Vogtle to maintain full-core discharge capability for both units until the year 2014. To maintain pool discharge capability at Plant Hatch, effective June 2000, an on-site dry storage facility for Plant Hatch became operational. Sufficient dry storage capacity is believed to be available to continue dry storage operations at Plant Hatch through the life of the plant. Procurement of on-site dry storage capacity at Plant Vogtle will commence in sufficient time to maintain pool full-core discharge capability.

Also, the Energy Policy Act of 1992 required the establishment of a Uranium Enrichment Decontamination and Decommissioning Fund, which is to be funded in part by a special assessment on utilities with nuclear plants. The assessment will be paid over a 15-year period, which began in 1993. This fund will be used by the DOE for the decontamination and decommissioning of its nuclear fuel enrichment facilities. The law provides that utilities will recover these payments in the same manner as any other fuel expense. The Company -- based on its ownership interests -- estimates its remaining liability under this law at December 31, 2001 to be approximately $16 million. This obligation is recorded in the accompanying Balance Sheets.

Depreciation and Nuclear Decommissioning

Depreciation of the original cost of depreciable utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.3 percent in 2001, 2000, and 1999. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost -- together with the cost of removal, less salvage -- is charged to accumulated depreciation. Minor items of property included in the original cost of the plant are retired when the related property unit is retired. Depreciation expense includes an amount for the expected costs of decommissioning nuclear facilities and removal of other facilities.

Nuclear Regulatory Commission (NRC) regulations require all licensees operating commercial power reactors to establish a plan for providing, with reasonable assurance, funds for decommissioning. The Company has established external trust funds to comply with the NRC's regulations. Earnings on the trust funds are considered in determining decommissioning expense. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed plans with the NRC to ensure that -- over time -- the deposits and earnings of the external trust funds will provide the minimum funding amounts prescribed by the NRC.

The Company periodically conducts site-specific studies to estimate the actual cost of decommissioning its nuclear generating facilities. Site study cost is the estimate to decommission the facility as of the site study year, and ultimate cost is the estimate to decommission the facility as of its retirement date. The estimated site study costs based on the most current study and ultimate costs assuming an inflation rate of 4.7 percent for the Company's ownership interests are as follows:

	Plant Hatch	Plant Vogtle
Site study basis (year)	2000	2000
Decommissioning periods:		
Beginning year	2014	2027
Completion year	2042	2045
	(in millions)	
Site study costs:		
Radiated structures	$486	$420
Non-radiated structures	37	48
Total	$523	$468
	(in millions)	
Ultimate costs:		
Radiated structures	$1,004	$1,468
Non-radiated structures	79	166
Total	$1,083	$1,634

The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from the above estimates because of changes in the assumed date of decommissioning, changes in the NRC requirements, changes in the assumptions used in making the estimates, changes in regulatory requirements, changes in technology, and changes in costs of labor, materials, and equipment.

Annual provisions for nuclear decommissioning expense are based on an annuity method as approved by the GPSC. The amounts expensed in 2001 and fund balances as of December 31, 2001 were:

	Plant Hatch	Plant Vogtle
	(in millions)	
Amount expensed in 2001	$20	$9
	(in millions)	
Accumulated provisions:		
External trust funds, at fair value	$229	$135
Internal reserves	20	12
Total	$249	$147

Effective January 1, 2002, the GPSC decreased the annual provision for decommissioning expenses to $8 million. This amount is based on the NRC generic estimate to decommission the radioactive portion of the facilities as of 2000 of $383 million and $282 million for Plants Hatch and Vogtle, respectively. The ultimate costs associated with the 2000 NRC minimum funding requirements are $823 million and $1.03 billion for Plants Hatch and Vogtle, respectively. Significant assumptions include an estimated inflation rate of 4.7 percent and an estimated trust earnings rate of 6.5 percent. The Company expects the GPSC to periodically review and adjust, if necessary, the amounts collected in rates for the anticipated cost of decommissioning.

In January 2002, the NRC granted the Company a 20-year extension of the licenses for both units at Plant Hatch which permits the operation of units 1 and 2 until 2034 and 2038, respectively. The decommissioning costs disclosed above do not reflect this extension.

Income Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Investment tax credits utilized are deferred and amortized to income over the average lives of the related property.

Allowance for Funds Used During Construction (AFUDC)

AFUDC represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, it increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation expense. For the years 2001, 2000, and 1999, the average AFUDC rates were 6.33 percent, 6.74 percent, and 5.61 percent, respectively. AFUDC, net of taxes, as a percentage of net income after dividends on preferred stock, was less than 3.0 percent for 2001, 2000, and 1999.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost, less regulatory disallowances and impairments. Original cost includes: materials; labor; payroll-related costs such as taxes, pensions, and other benefits; and the cost of funds used during construction. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense. The cost of replacements of property (exclusive of minor items of property) is capitalized.

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Comprehensive Income

Comprehensive income -- consisting of net income and changes in the fair value of qualifying cash flow hedges, net of income taxes -- is presented in the financial statements. The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners.

Financial Instruments

Effective January 2001, the Company adopted FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended. The impact on net income was immaterial.

The Company uses derivative financial instruments to hedge exposures to fluctuations in interest rates, foreign currency exchange rates, and certain commodity prices. Gains and losses on qualifying hedges are deferred and recognized either in income or as an adjustment to the carrying amount of the hedged item when the transaction occurs.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

The Company and its affiliates, through SCS acting as their agent, enter into commodity related forward and option contracts to limit exposure to changing prices on certain fuel purchases and electricity purchases and sales. Substantially all of the Company's bulk energy purchases and sales contracts meet the definition of a derivative under Statement No. 133. In many cases, these fuel and electricity contracts qualify for normal purchase and sale exceptions under Statement No. 133 and are accounted for under the accrual method. Other contracts qualify as cash flow hedges of anticipated transactions, resulting in the deferral of related gains and losses, and are recorded in other comprehensive income until the hedged transactions occur. Any ineffectiveness is recognized currently in net income. Contracts that do not qualify for the normal purchase and sale exception and that do not meet the hedge requirements are marked to market through current period income.

The Company's financial instruments for which the carrying amounts did not approximate fair value at December 31 were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
At December 31, 2001	\$3,190	\$3,190
At December 31, 2000	\$2,959	\$2,912
Preferred securities:		
At December 31, 2001	\$789	\$782
At December 31, 2000	\$789	\$761

The fair values for securities were based on either closing market prices or closing prices of comparable instruments.

Materials and Supplies

Generally, materials and supplies include the cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, when installed.

2. RETIREMENT BENEFITS

The Company has defined benefit, trusteed pension plans that cover substantially all employees. The Company provides certain medical care and life insurance benefits for retired employees. Substantially all these employees may become eligible for such benefits when they retire. The Company funds postretirement trusts to the extent required by the GPSC and the FERC. In late 2000, the Company adopted several pension and postretirement benefits plan changes that had the effect of increasing benefits to both current and future retirees. The measurement date for plan assets and obligations is September 30 of each year.

The weighted average rates assumed in the actuarial calculations for both the pension and postretirement benefit plans were:

	2001	2000
Discount	7.50%	7.50%
Annual salary increase	5.00	5.00
Expected long-term return on plan assets	8.50	8.50

Pension Plan

Changes during the year in the projected benefit obligations and in the fair value of plan assets were as follows:

	Projected Benefit Obligations	
	2001	2000
	(in millions)	
Balance at beginning of year	$1,322	$1,275
Service cost	35	32
Interest cost	101	94
Benefits paid	(74)	(67)
Actuarial gain and employee transfers	64	(12)
Balance at end of year	$1,448	$1,322

	Plan Assets	
	2001	2000
	(in millions)	
Balance at beginning of year	$2,464	$2,107
Actual return on plan assets	(356)	385
Benefits paid	(62)	(58)
Employee transfers	(2)	30
Balance at end of year	$2,044	$2,464

The accrued pension costs recognized in the Balance Sheets were as follows:

	2001	2000
	(in millions)	
Funded status	$596	$1,142
Unrecognized transition obligation	(22)	(26)
Unrecognized prior service cost	98	44
Unrecognized net actuarial gain	(444)	(1,013)
Prepaid asset recognized in the Balance Sheets	$228	$ 147

Components of the plan's net periodic cost were as follows:

	2001	2000	1999
	(in millions)		
Service cost	$ 35	$ 33	$ 33
Interest cost	101	94	86
Expected return on plan assets	(168)	(152)	(137)
Recognized net actuarial gain	(31)	(26)	(17)
Net amortization	3	(1)	-
Net pension income	$ (60)	$ (52)	$ (35)

Postretirement Benefits

Changes during the year in the accumulated benefit obligations and in the fair value of plan assets were as follows:

	Accumulated Benefit Obligations	
	2001	2000
	(in millions)	
Balance at beginning of year	$495	$438
Service cost	9	7
Interest cost	39	36
Benefits paid	(24)	(21)
Actuarial gain and employee transfers	23	35
Balance at end of year	$542	$495

	Plan Assets	
	2001	2000
	(in millions)	
Balance at beginning of year	$198	$177
Actual return on plan assets	(26)	12
Employer contributions	47	30
Benefits paid	(24)	(21)
Balance at end of year	$195	$198

The accrued postretirement costs recognized in the Balance Sheets were as follows:

	2001	2000
	(in millions)	
Funded status	$(347)	$(297)
Unrecognized transition obligation	105	113
Unrecognized prior service cost	104	60
Unrecognized (gain)/loss	5	(13)
Fourth quarter contributions	27	27
Accrued liability recognized in the Balance Sheets	$(106)	$(110)

Components of the plans' net periodic cost were as follows:

	2001	2000	1999
	(in millions)		
Service cost	$ 9	$ 7	$ 8
Interest cost	39	36	30
Expected return on plan assets	(19)	(16)	(10)
Recognized net actuarial loss	-	-	1
Net amortization	14	12	9
Net postretirement cost	$43	$39	$38

An additional assumption used in measuring the accumulated postretirement benefit obligations was a weighted average medical care cost trend rate of 9.25 percent for 2001, decreasing gradually to 5.25 percent through the year 2010, and remaining at that level thereafter. An annual increase or decrease in the assumed medical care cost trend rate of 1 percent would affect the accumulated benefit obligation and the service and interest cost components at December 31, 2001 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$54	$46
Service and interest costs	5	4

Employee Savings Plan

The Company sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides a 75 percent matching contribution up to 6 percent of an employee's base salary. Total matching contributions made to the plan for the years 2001, 2000, and 1999 were $16 million, $15 million, and $15 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In the opinion of management, after consultation with legal counsel, the ultimate disposition of these matters is not expected to have a material adverse effect on the Company's financial condition.

Retail Rate Orders

On December 20, 2001, the GPSC approved a new three-year retail rate order for the Company ending December 31, 2004. Under the terms of the order, earnings will be evaluated against a retail return on common equity range of 10 percent to 12.95 percent. Two-thirds of any earnings above the 12.95 percent return will be applied to rate refunds, with the remaining one-third retained by the Company. Retail rates were decreased by $118 million effective January 1, 2002.

Under a previous three-year order ending December 2001, the Company's earnings were evaluated against a retail return on common equity range of 10 percent to 12.5 percent. The order further provided for $85 million in each year, plus up to $50 million of any earnings above the 12.5 percent return during the second and third years, to be applied to accelerated amortization or depreciation of assets. Two-thirds of any additional earnings above the 12.5 percent return were applied to rate refunds, with the remaining one-third retained by the Company. Pursuant to the order, the Company recorded $336 million of accelerated amortization and interest thereon which has been credited to a regulatory liability account as mandated by the GPSC.

Under the new rate order, the accelerated amortization and the interest will be amortized equally over three years as a credit to expense beginning in 2002. Effective January 1, 2002, the Company discontinued recording accelerated depreciation and amortization. The Company will not file for a general base rate increase unless its projected retail return on common equity falls below 10 percent. Georgia Power is required to file a general rate case on July 1, 2004, in response to which the GPSC would be expected to determine whether the rate order should be continued, modified, or discontinued.

In 2000 and 1999, the Company recorded $44 million and $79 million, respectively, of revenue subject to refund for estimated earnings above 12.5 percent retail return on common equity. Refunds applicable to 2000 and 1999 were made to customers in 2001 and 2000, respectively.

Environmental Protection Agency (EPA) Litigation

On November 3, 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia. The complaint alleges violations of the prevention of significant deterioration and new source review provisions of the Clean Air Act with respect to coal-fired generating facilities at the Company's Bowen and Scherer plants. The civil action requests penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units beginning at the point of the alleged violations. The Clean Air Act authorizes civil penalties of up to $27,500 per day, per violation at each generating unit. Prior to January 30, 1997, the penalty was $25,000 per day.

The EPA concurrently issued a notice of violation to the Company relating to these two plants. In early 2000, the EPA filed a motion to amend its complaint to add the violations alleged in its notice of violation. The complaint and the notice of violation are similar to those brought against and issued to several other electric utilities. The complaint and the notice of violation allege that the Company failed to secure necessary permits or install additional pollution control equipment when performing maintenance and construction at coal burning plants constructed or under construction prior to 1978. The Company believes that it complied with applicable laws and the EPA's regulations and interpretations in effect at the time the work in question took place.

The case against the Company has been stayed since the spring of 2001 pending a ruling by the U.S. Court of Appeals for the Eleventh Circuit in the appeal of a very similar Clean Air Act / New Source Review enforcement action brought by EPA against the Tennessee Valley Authority (TVA). The TVA case involves many of the same legal issues raised by the actions against the Company. Because the outcome of the TVA case could have a significant adverse impact on Georgia Power, the Company is a party to that case as well. The federal court in Georgia is currently considering a motion by the EPA to reopen the Georgia case. The Company has opposed that motion. An adverse outcome of this matter could require substantial capital expenditures that cannot be determined at this time and possibly require payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

Other Environmental Contingencies

The Company has been designated as a potentially responsible party at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation and Liability Act. Georgia Power has recognized $33 million in cumulative expenses through December 31, 2001 for the assessment and anticipated cleanup of sites on the Georgia Hazardous Sites Inventory. In addition, in 1995 the EPA designated Georgia Power and four other unrelated entities as potentially responsible parties at a site in Brunswick, Georgia that is listed on the federal National Priorities List. Georgia Power has contributed to the removal and remedial investigation and feasibility study costs for the site. Additional claims for recovery of natural resource damages at the site are anticipated. As of December 31, 2001, Georgia Power had recorded approximately $6 million in cumulative expenses associated with Georgia Power's agreed-upon share of the removal and remedial investigation and feasibility study costs for the Brunswick site.

The final outcome of these matters cannot now be determined. However, based on the currently known conditions at these sites and the nature and extent of Georgia Power's activities relating to these sites, management does not believe that the Company's cumulative liability at these sites would be material to the financial statements.

Nuclear Performance Standards

The GPSC has adopted a nuclear performance standard for the Company's nuclear generating units under which the performance of Plants Hatch and Vogtle is evaluated every three years. The performance standard is based on each unit's capacity factor as compared to the average of all comparable U.S. nuclear units operating at a capacity factor of 50 percent or higher during the three-year period of evaluation. Depending on the performance of the units, the Company could receive a monetary award or penalty under the performance standards criteria.

The GPSC has approved performance awards of approximately $11.7 million and $7.8 million for performance during the 1993-1995 period and the 1996-1998 period, respectively. These awards are collected through the retail fuel cost recovery provision and recognized in income over 36-month periods that began in January 1997 and 2000, respectively, as mandated by the GPSC.

Race Discrimination Litigation

On July 28, 2000, a lawsuit alleging race discrimination was filed by three Georgia Power employees against the Company, Southern Company, and SCS in the United States District Court for the Northern District of Georgia. The lawsuit also raised claims on behalf of a purported class. The plaintiffs seek compensatory and punitive damages in an unspecified amount, as well as injunctive relief. On August 14, 2000, the lawsuit was amended to add four more plaintiffs. Also, an additional subsidiary of Southern Company, Southern Company Energy Solutions, Inc., was named a defendant.

On October 11, 2001, the district court denied plaintiffs' motion for class certification. The plaintiffs filed a motion to reconsider the order denying class certification, and the court denied the plaintiffs' motion to reconsider. On December 28, 2001, the plaintiffs filed a petition in the United States Court of Appeals for the Eleventh Circuit seeking permission to file an appeal of the October 11 decision. The defendants filed a brief in opposition of the petition on January 18, 2002. Discovery of the seven named plaintiffs' individual claims that remain in the case is ongoing. The final outcome of the case cannot be determined.

4. COMMITMENTS

Construction Program

Georgia Power had three new generation projects under construction during 2001. They included two units at Plant Dahlberg, a ten-unit, 800 megawatt combustion turbine facility; two combined cycle units totaling 1,132 megawatts at Plant Wansley; and Plant Goat Rock, a two-unit, 1,181 megawatt combined cycle facility. All three of these projects have been transferred to Southern Power Company, a new Southern Company affiliate formed in 2001 to construct, own, and manage wholesale generating assets in the Southeast. The ten Dahlberg units and two Goat Rock units were transferred in 2001 and the transfer of the two Wansley units was completed in January 2002. Significant construction of transmission and distribution facilities and projects to remain in compliance with environmental requirements will continue. The Company currently estimates property additions to be approximately $1.0 billion in 2002, $0.8 billion in 2003, and $0.8 billion in 2004.

In connection with the transfer of Plants Dahlberg, Goat Rock, and Wansley, the Company has assigned $61 million in vendor equipment contracts to Southern Power. While the Company could be obligated to assume responsibility for these contracts if Southern Power fails to meet these commitments, Southern Company has entered into limited keep-well arrangements whereby Southern Company would contribute funds to Southern Power either through loans or capital contributions in order to fund performance by Southern Power as equipment purchaser under certain contingencies. Southern Company has also guaranteed Southern Power obligations totaling $6.6 million for the Company's construction of transmission interconnection facilities to these plants.

The construction program is subject to periodic review and revision, and actual construction costs may vary from estimates because of numerous factors, including, but not limited to, changes in business conditions, load growth estimates, environmental regulations, and regulatory requirements.

Fuel Commitments

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement of fossil and nuclear fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Total estimated long-term fossil and nuclear fuel commitments at December 31, 2001 were as follows:

Year	Minimum Obligations
	(in millions)
2002	$1,234
2003	1,115
2004	617
2005	527
2006	521
2007 and beyond	1,857
Total	$5,871

Additional commitments for coal and for nuclear fuel will be required in the future to supply the Company's fuel needs.

In addition, SCS acts as agent for the five operating companies and Southern Power with regard to natural gas purchases. Natural gas purchases (in dollars) are based on various indices at the actual time of delivery; therefore, only the volume commitments are firm and disclosed in the following chart. The committed volumes, as of December 31, 2001 are as follows:

Year	Natural Gas
	(MMBtu)
2002	18,927,055
2003	30,434,645
2004	30,352,580
2005	23,050,128
2006	20,038,214
2007 and beyond	7,153,129
Total	129,955,751

Purchased Power Commitments

The Company and an affiliate, Alabama Power, own equally all of the outstanding capital stock of Southern Electric Generating Company (SEGCO), which owns electric generating units with a total rated capacity of 1,020 megawatts, as well as associated transmission facilities. The capacity of the units has been sold equally to the Company and Alabama Power under a contract which, in substance, requires payments sufficient to provide for the operating expenses, taxes, debt service, and return on investment, whether or not SEGCO has any capacity and energy available. The term of the contract extends automatically for two-year periods, subject to either party's right to cancel upon two year's notice. The Company's share of expenses included in purchased power from affiliates in the Statements of Income is as follows:

	2001	2000	1999
	(in millions)		
Energy	$52	$57	$51
Capacity	30	30	29
Total	$82	$87	$80

The Company has commitments regarding a portion of a 5 percent interest in Plant Vogtle owned by Municipal Electric Authority of Georgia (MEAG) that are in effect until the latter of the retirement of the plant or the latest stated maturity date of MEAG's bonds issued to finance such ownership interest. The payments for capacity are required whether or not any capacity is available. The energy cost is a function of each unit's variable operating costs. Except as noted below, the cost of such capacity and energy is included in purchased power from non-affiliates in the Company's Statements of Income. Capacity payments totaled $59 million, $58 million, and $57 million in 2001, 2000, and 1999, respectively. The current projected Plant Vogtle capacity payments are:

Year	Capacity Payments
	(in millions)
2002	$ 58
2003	59
2004	55
2005	55
2006	55
2007 and beyond	483
Total	$765

Portions of the payments noted above relate to costs in excess of Plant Vogtle's allowed investment for ratemaking purposes. The present value of these portions was written off in 1987 and 1990.

The Company has entered into other various long-term commitments for the purchase of electricity. Estimated total long-term obligations at December 31, 2001 were as follows:

Year	Affiliated	Non-Affiliated
	(in millions)	
2002	$ 66	$ 39
2003	123	41
2004	183	40
2005	198	40
2006	197	40
2007 and beyond	1,138	396
Total	$1,905	$596

Operating Leases

The Company has entered into coal rail car rental agreements with various terms and expiration dates. These expenses totaled $14 million for 2001, $16 million for 2000, and $11 million for 1999. At December 31, 2001, estimated minimum rental commitments for these noncancelable operating leases were as follows:

Year	Minimum Obligations
	(in millions)
2002	$ 15
2003	15
2004	15
2005	15
2006	15
2007 and beyond	91
Total	$166

In addition to the rental commitments above, the Company has obligations upon expiration of certain of the rail car leases with respect to the residual value of the leased property. These leases expire in 2004 and 2010, and the Company's maximum obligations are $13 million and $40 million, respectively. At the termination of the leases, at the Company's option, the Company may either exercise its purchase option or the property can be sold to a third party. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligation.

5. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act of 1988, the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the Company's nuclear power plants. The Act provides funds up to $9.5 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $200 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of nuclear reactors. The Company could be assessed up to $88 million per incident for each licensed reactor it operates but not more than an aggregate of $10 million per incident to be paid in a calendar year for each reactor. Such maximum assessment for the Company, excluding any applicable state premium taxes -- based on its ownership and buyback interests -- is $178 million per incident but not more than an aggregate of $20 million to be paid for each incident in any one year.

The Company is a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $500 million for members' nuclear generating facilities.

Additionally, the Company has policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $2.25 billion for losses in excess of the $500 million primary coverage. This excess insurance is also provided by NEIL.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of between 8 to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After this deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years.

Under each of the NEIL policies, members are subject to assessments if losses each year exceed the accumulated funds available to the insurer under that policy. The current maximum annual assessments for the Company under the three NEIL policies would be $39 million.

Following the terrorist attacks of September 2001, both ANI and NEIL confirmed that terrorist acts against commercial nuclear power stations would be covered under their insurance. Both companies, however, revised their policy terms on a prospective basis to include an industry aggregate for all terrorist acts. The NEIL aggregate, which applies to all claims stemming from terrorism within a 12 month duration, is $3.24 billion plus any amounts that would be available through reinsurance or indemnity from an outside source. The ANI cap is $200 million in a policy year.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies should be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the Company or to its bond trustees as may be appropriate under the policies and applicable trust indentures.

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes.

6. JOINT OWNERSHIP AGREEMENTS

Except as otherwise noted, the Company has contracted to operate and maintain all jointly owned generating facilities. The Company jointly owns the Rocky Mountain pumped storage hydroelectric plant with Oglethorpe Power Company who is the operator of the plant. The Company also jointly owns Plant McIntosh with Savannah Electric and Power Company who operates the plant. The Company and Florida Power Corporation (FPC) jointly own a combustion turbine unit (Intercession City) operated by FPC.

The Company includes its proportionate share of plant operating expenses in the corresponding operating expenses in the Statements of Income.

At December 31, 2001, the Company's percentage ownership and investment (exclusive of nuclear fuel) in jointly owned facilities in commercial operation were as follows:

Facility (Type)	Company Ownership	Investment	Accumulated Depreciation
		(in millions)	
Plant Vogtle (nuclear)	45.7%	$3,304	$1,793
Plant Hatch (nuclear)	50.1	881	668
Plant Wansley (coal)	53.5	309	152
Plant Scherer (coal)			
Units 1 and 2	8.4	112	56
Unit 3	75.0	545	221
Plant McIntosh			
Common Facilities (combustion-turbine)	75.0	24	2
Rocky Mountain (pumped storage)	25.4	169	78
Intercession City (combustion-turbine)	33.3	12	1

7. LONG-TERM POWER SALES AGREEMENTS

The Company and the other operating companies of Southern Company have long-term contractual agreements for the sale of capacity and energy to certain non-affiliated utilities located outside the system's service area. These agreements consist of firm unit power sales pertaining to capacity from specific generating units. Because energy is generally sold at cost under these agreements, it is primarily the capacity revenues that affect the Company's profitability.

The Company's capacity revenues were as follows:

Year	Revenues	Capacity
	(in millions)	(megawatts)
2001	$ 26	102
2000	30	124
1999	32	162

Unit power from specific generating plants is being sold to Florida Power & Light Company, FPC, and Jacksonville Electric Authority. Under these agreements, approximately 102 megawatts of capacity is scheduled to be sold annually for periods after 2001 with a minimum of three years notice until the expiration of the contracts in 2010.

8. INCOME TAXES

At December 31, 2001, tax-related regulatory assets were $544 million and tax-related regulatory liabilities were $229 million. The assets are attributable to tax benefits flowed through to customers in prior years and to taxes applicable to capitalized interest. The liabilities are attributable to deferred taxes previously recognized at rates higher than current enacted tax law and to unamortized investment tax credits.

Details of the federal and state income tax provisions are as follows:

	2001	2000	1999
Total provision for income taxes:		(in millions)	
Federal:			
Current	$352	$342	$333
Deferred	(46)	(34)	(34)
	306	308	299
State:			
Current	61	48	54
Deferred	(8)	(5)	(6)
Deferred investment tax credits	5	10	5
Total	$364	$361	$352

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2001	2000
	(in millions)	
Deferred tax liabilities:		
Accelerated depreciation	$1,722	$1,755
Property basis differences	660	683
Other	295	243
Total	2,677	2,681
Deferred tax assets:		
Other property basis differences	178	189
Federal effect of state deferred taxes	88	91
Other deferred costs	257	208
Other	40	37
Total	563	525
Net deferred tax liabilities	2,114	2,156
Portion included in current assets	50	27
Accumulated deferred income taxes in the Balance Sheets	$2,164	$2,183

Deferred investment tax credits are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the Statements of Income. Credits amortized in this manner amounted to $15 million in 2001, 2000, and 1999. At December 31, 2001, all investment tax credits available to reduce federal income taxes payable had been utilized.

A reconciliation of the federal statutory tax rate to the effective income tax rate is as follows:

	2001	2000	1999
Federal statutory rate	35%	35%	35%
State income tax, net of federal deduction	4	4	4
Non-deductible book depreciation	2	2	2
Other	(4)	(2)	(2)
Effective income tax rate	37%	39%	39%

Southern Company and its subsidiaries file a consolidated federal income tax return. Under a joint consolidated income tax agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis. In accordance with Internal Revenue Service regulations, each company is jointly and severally liable for the tax liability.

9. CAPITALIZATION

First Mortgage Bond Indenture Restrictions

The Company's first mortgage bond indenture contains various restrictions that remain in effect as long as the bonds are outstanding. However, the Company expects to discharge its first mortgage bond indenture by spring 2002 and to be released from all indenture requirements. At December 31, 2001, $1.037 billion of retained earnings and paid-in capital was unrestricted for the payment of cash dividends or any other distributions under terms of the mortgage indenture. The Company has no restrictions on the amount of indebtedness it may incur.

Preferred Securities

Statutory business trusts formed by the Company, of which the Company owns all the common securities, have issued mandatorily redeemable preferred securities as follows:

	Date of Issue	Amount (millions)	Rate	Notes (millions)	Maturity Date
Trust I	8/1996	$225.00	7.75%	$232	6/2036
Trust II	1/1997	175.00	7.60	180	12/2036
Trust III	6/1997	189.25	7.75	195	3/2037
Trust IV	2/1999	200.00	6.85	206	3/2029

Substantially all of the assets of each trust are junior subordinated notes issued by the Company in the respective approximate principal amounts set forth above.

The Company considers that the mechanisms and obligations relating to the preferred securities, taken together, constitute a full and unconditional guarantee by the Company of the Trusts' payment obligations with respect to the preferred securities.

The Trusts are subsidiaries of the Company, and accordingly are consolidated in the Company's financial statements.

Pollution Control Bonds

The Company has incurred obligations in connection with the sale by public authorities of tax-exempt pollution control revenue bonds. The Company has authenticated and delivered to trustees an aggregate of $7.8 million of its first mortgage bonds outstanding at December 31, 2001, which are pledged as security for its obligations under pollution control revenue contracts. The redemption of these securities will occur in March 2002.

Senior Notes

In February 2000, February 2001, and May 2001, the Company issued unsecured senior notes. The proceeds of these issues were used to redeem higher cost long-term debt and to reduce short-term borrowing. The senior notes are, in effect, subordinated to all secured debt of the Company.

Bank Credit Arrangements

At the beginning of 2002, the Company had unused credit arrangements with banks totaling $1.8 billion, of which $1.3 billion expires at various times during 2002 and $500 million expires at April 24, 2003.

Of the total $1.8 billion in unused credit, $1.65 billion is a syndicated credit arrangement with $1.15 billion expiring April 19, 2002 and $500 million expiring April 24, 2003. Upon expiration, the $1.15 billion agreement provides the option of converting borrowings into two-year term loans. Both agreements contain stated borrowing rates but also allow for competitive bid loans. In addition, the agreements require payment of commitment fees based on the unused portions of the commitments. Annual fees are also paid to the agent bank.

Approximately $115 million of the $1.3 billion arrangements expiring during 2002 allow for two-year term loans executable upon the expiration date of the facilities. All of the arrangements include stated borrowing rates but also allow for negotiated rates. These agreements also require payment of commitment fees based on the unused portion of the commitments or the maintenance of compensating balances with the banks. These balances are not legally restricted from withdrawal.

This $1.8 billion in unused credit arrangements provides liquidity support to the Company's variable rate pollution control bonds. The amount of variable rate pollution control bonds outstanding requiring that liquidity support as of December 31, 2001 was $984 million.

In addition, the Company borrows under uncommitted lines of credit with banks and through commercial paper programs that has the liquidity support of committed bank credit arrangements. Average compensating balances held under these committed facilities were not material in 2001. The amount of commercial paper outstanding at December 31, 2001 was $707.6 million

Other Long-Term Debt

Assets acquired under capital leases are recorded in the Balance Sheets as utility plant in service, and the related obligations are classified as long-term debt. At December 31, 2001 and 2000, the Company had a capitalized lease obligation for its corporate headquarters building of $83 million with an interest rate of 8.1 percent. For ratemaking purposes, the GPSC has treated the lease as an operating lease and has allowed only the lease payments in cost of service. The difference between the accrued expense and the lease payments allowed for ratemaking purposes has been deferred and is being amortized to expense as ordered by the GPSC. At December 31, 2001 and 2000, the interest and lease amortization deferred on the Balance Sheets are $54 million and $55 million, respectively.

Assets Subject to Lien

The Company's mortgage dated as of March 1, 1941, as amended and supplemented, securing the first mortgage bonds issued by the Company, constitutes a direct lien on substantially all of the Company's fixed property and franchises. Georgia Power expects to discharge its first mortgage bond indenture by spring 2002 and that the lien will be removed.

Securities Due Within One Year

A summary of the improvement fund requirements and scheduled maturities and redemptions of securities due within one year at December 31 is as follows:

	2001	2000
	(in millions)	
Capital lease	$ 2	$2
First mortgage bonds	2	-
Pollution control bonds	8	-
Senior notes	300	-
Total	$312	$2

The Company's first mortgage bond indenture includes an improvement fund requirement that amounts to 1 percent of each outstanding series of bonds authenticated under the indenture prior to January 1 of each year, other than those issued to collateralize pollution control obligations. The requirement may be satisfied by June 1 of each year by depositing cash, reacquiring bonds, or by pledging additional property equal to 1 2/3 times the requirement. However, the Company expects to discharge its first mortgage bond indenture by spring 2002 and to be released from all indenture requirements.

Serial maturities through 2006 applicable to total long-term debt are as follows: $312 million in 2002; $352 million in 2003; $2 million in 2004; $154 million in 2005; and $153 million in 2006.

10. QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized quarterly financial information for 2001 and 2000 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred Stock
	(in millions)		
March 2001	$1,108	$249	$108
June 2001	1,259	322	163
September 2001	1,579	515	298
December 2001	1,020	126	41
March 2000	$ 992	$223	$ 94
June 2000	1,221	311	148
September 2000	1,545	537	283
December 2000	1,113	162	34

The Company's business is influenced by seasonal weather conditions.

SELECTED FINANCIAL AND OPERATING DATA 1997-2001

Georgia Power Company 2001 Annual Report

	2001	2000	1999	1998	1997
Operating Revenues (in thousands)	$4,965,794	$4,870,618	$4,456,675	$4,738,253	$4,385,717
Net Income after Dividends on Preferred Stock (in thousands)	$610,335	$559,420	$541,383	$570,228	$593,996
Cash Dividends on Common Stock (in thousands)	$527,300	$549,600	$543,000	$536,600	$520,000
Return on Average Common Equity (percent)	14.12	13.66	14.02	14.61	14.53
Total Assets (in thousands)	$13,565,941	$13,075,767	$12,361,860	$12,033,618	$12,573,728
Gross Property Additions (in thousands)	$1,389,751	$1,078,163	$790,464	$499,053	$475,921
Capitalization (in thousands):					
Common stock equity	$4,397,485	$4,249,544	$3,938,210	$3,784,172	$4,019,728
Preferred stock	14,569	14,569	14,952	15,527	157,247
Company obligated mandatorily redeemable preferred securities	789,250	789,250	789,250	689,250	689,250
Long-term debt	2,961,726	3,041,939	2,688,358	2,744,362	2,982,835
Total (excluding amounts due within one year)	$8,163,030	$8,095,302	$7,430,770	$7,233,311	$7,849,060
Capitalization Ratios (percent):					
Common stock equity	53.9	52.5	53.0	52.3	51.2
Preferred stock	0.2	0.2	0.2	0.2	2.0
Company obligated mandatorily redeemable preferred securities	9.6	9.7	10.6	9.5	8.8
Long-term debt	36.3	37.6	36.2	38.0	38.0
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0
Security Ratings:					
First Mortgage Bonds -					
Moody's	A1	A1	A1	A1	A1
Standard and Poor's	A	A	A+	A+	A+
Fitch	AA-	AA-	AA-	AA-	AA-
Preferred Stock -					
Moody's	Baa1	a2	a2	a2	a2
Standard and Poor's	BBB+	BBB+	A-	A	A
Fitch	A	A	A+	A+	A+
Unsecured Long-Term Debt -					
Moody's	A2	A2	A2	A2	A2
Standard and Poor's	A	A	A	A	A
Fitch	A+	A+	A+	A+	A+
Customers (year-end):					
Residential	1,698,407	1,669,566	1,632,450	1,596,488	1,561,675
Commercial	244,674	237,977	229,524	221,180	211,672
Industrial	8,046	8,533	8,958	9,485	9,988
Other	3,239	3,159	3,060	3,034	2,748
Total	1,954,366	1,919,235	1,873,992	1,830,187	1,786,083
Employees (year-end):	9,048	8,860	8,961	8,371	8,354

	2001	2000	1999	1998	1997
Operating Revenues (in thousands):					
Residential	$ 1,507,031	$1,535,684	$ 1,410,099	$ 1,486,699	$ 1,326,787
Commercial	1,682,918	1,620,466	1,527,880	1,591,363	1,493,353
Industrial	1,106,420	1,154,789	1,143,001	1,170,881	1,110,311
Other	52,943	6,399	(30,892)	49,274	47,848
Total retail	4,349,312	4,317,338	4,050,088	4,298,217	3,978,299
Sales for resale - non-affiliates	366,085	297,643	210,104	259,234	282,365
Sales for resale - affiliates	99,411	96,150	76,426	81,606	38,708
Total revenues from sales of electricity	4,814,808	4,711,131	4,336,618	4,639,057	4,299,372
Other revenues	150,986	159,487	120,057	99,196	86,345
Total	$4,965,794	$4,870,618	$4,456,675	$4,738,253	$4,385,717
Kilowatt-Hour Sales (in thousands):					
Residential	20,119,080	20,693,481	19,404,709	19,481,486	17,295,022
Commercial	26,493,255	25,628,402	23,715,485	22,861,391	21,134,346
Industrial	25,349,477	27,543,265	27,300,355	27,283,147	26,701,685
Other	583,007	568,906	551,451	543,462	538,163
Total retail	72,544,819	74,434,054	70,972,000	70,169,486	65,669,216
Sales for resale - non-affiliates	8,110,096	6,463,723	5,060,931	6,438,891	6,795,300
Sales for resale - affiliates	3,133,485	2,435,106	1,795,243	2,038,400	1,706,699
Total	83,788,400	83,332,883	77,828,174	78,646,777	74,171,215
Average Revenue Per Kilowatt-Hour (cents):					
Residential	7.49	7.42	7.27	7.63	7.67
Commercial	6.35	6.32	6.44	6.96	7.07
Industrial	4.36	4.19	4.19	4.29	4.16
Total retail	6.00	5.80	5.71	6.13	6.06
Sales for resale	4.14	4.43	4.18	4.02	3.78
Total sales	5.75	5.65	5.57	5.90	5.80
Residential Average Annual Kilowatt-Hour Use Per Customer	11,933	12,520	12,006	12,314	11,171
Residential Average Annual Revenue Per Customer	$893.84	$929.11	$872.48	$939.73	$857.01
Plant Nameplate Capacity Ratings (year-end) (megawatts)	14,474	15,114	14,474	14,437	14,437
Maximum Peak-Hour Demand (megawatts):					
Winter	11,977	12,014	11,568	11,959	10,407
Summer	14,294	14,930	14,575	13,923	13,153
Annual Load Factor (percent)	61.7	61.6	58.9	58.7	57.4
Plant Availability (percent):					
Fossil-steam	88.5	86.1	84.3	86.0	85.8
Nuclear	94.4	91.5	89.3	91.6	88.8
Source of Energy Supply (percent):					
Coal	58.5	62.3	63.0	62.3	64.3
Nuclear	18.1	17.4	18.0	18.3	18.8
Hydro	1.1	0.7	0.9	2.2	2.2
Oil and gas	0.4	1.8	1.6	2.2	0.6
Purchased power -					
From non-affiliates	7.8	8.1	6.6	6.5	2.7
From affiliates	14.1	9.7	9.9	8.5	11.4
Total	100.0	100.0	100.0	100.0	100.0

Directors

Juanita P. Baranco
Executive Vice President
Baranco Automotive Group

Anna R. Cablik
Owner and President
Anatek, Inc. & Anasteel & Supply Co., LLC

William A. Fickling, Jr.
Chairman of the Board
Beech Street Corporation

H. Allen Franklin
Chairman, President and Chief Executive Officer
Southern Company

L. G. Hardman III
Chairman of the Board and Chief Executive Officer
nBank.Corp, Inc.

James R. Lientz, Jr.
Retired

G. Joseph Prendergast
Retired

David M. Ratcliffe
President and Chief Executive Officer
Georgia Power Company

Richard W. Ussery
Chairman of the Board and Chief Executive Officer
TSYS

William Jerry Vereen
Chairman, President and Chief Executive Officer
Riverside Manufacturing Company

Carl Ware
Executive Vice President
The Coca-Cola Company

E. Jenner Wood, III
Chairman, President and Chief Executive Officer
SunTrust Bank, Georgia

Officers

David M. Ratcliffe
President and Chief
Executive Officer

William C. Archer, III
Executive Vice President
External Affairs

Thomas A. Fanning
Executive Vice President, Treasurer and
Chief Financial Officer

Judy M. Anderson
Senior Vice President
Charitable Giving

Ronnie L. Bates
Senior Vice President
Marketing

M. A. Brown
Senior Vice President
Distribution

James K. Davis
Senior Vice President
Employee/Corporate Relations

Leslie R. Sibert
Vice President
Transmission

Fred D. Williams
Senior Vice President
Resource Policy and Planning

Chris C. Womack
Senior Vice President
Fossil and Hydro Power

Rebecca A. Blalock
Vice President
Community and Economic Development

Robert L. Boyer
Vice President
Power Generation

A. Bryan Fletcher
Vice President
Region Operations

J. Kevin Fletcher
Vice President
Retail Sales and Service

O. Ben Harris
Vice President
Land

Chris M. Hobson
Vice President
Environmental Affairs

Ed F. Holcombe
Vice President
Governmental and Regulatory Affairs

Richard L. Holmes
Vice President
Metro and West Regions

E. Lamont Houston
Vice President
Metro and South Regions

Anne H. Kaiser
Vice President
Corporate Services

Frank J. McCloskey
Vice President
Diversity and Workplace Ethics

Phil Saunders
Vice President
Information Resources

C. S. Thrasher
Vice President, Comptroller and
Chief Accounting Officer

J. L. Wallace
Vice President
Customer Service

Janice G. Wolfe
Corporate Secretary

Wayne Boston
Assistant Secretary and
Assistant Treasurer

W. R. Hinson
Assistant Comptroller and Assistant
Corporate Secretary

Allen L. Leverett
Assistant Treasurer

General
This annual report is submitted for general information and is not intended for use in connection with any sale or purchase of, or any solicitation of offers to buy or sell, securities.

Profile
The Company produces and delivers electricity as an integrated utility to both retail and wholesale customers within the State of Georgia. The Company sells electricity to some 2.0 million customers within its service area of approximately 57,000 square miles. In 2001, retail energy sales accounted for 87 percent of the Company's total sales of 83.8 billion kilowatt-hours.

The Company is a wholly owned subsidiary of Southern Company, which is the parent company of five integrated Southeast utilities. There is no established public trading market for the Company's common stock.

Trustee, Registrar and Interest Paying Agent
All series of First Mortgage Bonds, Senior Notes, and Preferred Securities
The Chase Manhattan Bank
Corporate Trust Department
450 West 33rd Street
New York, NY 10001

Registrar, Transfer Agent, and Dividend Paying Agent
Preferred Stock
Southern Company Services, Inc.
Stockholder Services
P.O. Box 54250
Atlanta, GA 30308-0250
(800) 554-7626

Form 10-K
A copy of Form 10-K as filed with the Securities and Exchange Commission will be provided upon written request to the office of the Corporate Secretary. For additional information, contact the office of the Corporate Secretary at (404) 506-7450.

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