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Georgia Power Company 2000 Annual Report

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## SUMMARY

	2000	1999	Percent Change
<b>Financial Highlights</b> <i>(in millions):</i>			
Operating revenues	\$4,871	\$4,457	9.3
Operating expenses	\$3,637	\$3,262	11.5
Net income after dividends on preferred stock	\$559	\$541	3.3
<b>Operating Data:</b>			
Kilowatt-hour sales <i>(in millions):</i>			
Retail	74,434	70,972	4.9
Sales for resale – non-affiliates	6,464	5,061	27.7
Sales for resale – affiliates	2,435	1,795	35.6
Total	83,333	77,828	7.1
Customers served at year-end <i>(in thousands)</i>	1,919	1,874	2.4
Peak-hour demand <i>(in megawatts)</i>	14,930	14,575	2.4
<b>Capitalization Ratios</b> <i>(percent):</i>			
Common stock equity	52.5	53.0	
Preferred stock	0.2	0.2	
Company obligated mandatorily redeemable preferred securities	9.7	10.6	
Long-term debt	37.6	36.2	
<b>Return on Average Common Equity</b> <i>(percent)</i>	13.66	14.02	
<b>Ratio of Earnings to Fixed Charges</b> <i>(times)</i>	4.14	4.26	

## LETTER TO INVESTORS

Georgia Power Company 2000 Annual Report

I am pleased to report that Georgia Power met the challenges of record peak demand while recording outstanding financial and operational performance in 2000.

Georgia Power's earnings for 2000 totaled \$559 million, an \$18 million, or 3.3 percent increase, from 1999. This earnings increase resulted primarily from higher retail and wholesale sales as well as continued control of operating expenses. We earned a 13.7 percent return on average common equity during 2000.

The Company prospered in 2000 because we were effective at managing the fundamentals of our business – generating and supplying power to 1.9 million customers. Our customers set six peak demand records during the hot summer, topping out at 14,930 megawatts on August 18. To keep up with retail sales growth in our market, we are acquiring approximately 2700 megawatts of generation resources over the next four years.

In January, we faced an ice storm, which caused the worst power outages for our company since Hurricane Opal struck the state in 1995. We also weathered out-of-season tornadoes in southwest Georgia in February and severe thunderstorms in north Georgia in July, testing our ability to quickly and safely restore service to our customers.

For the third consecutive year, Georgia Power and the other Southern Company subsidiaries dominated 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, value, reliability, power quality, energy efficiency, easy to do business with and best account representatives. Hoping to maintain and enhance our reputation with customers, we launched several new initiatives in 2000 to re-establish customer service as our top priority.

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 \$1.2 billion in new capital investment projects and more than 12,000 new jobs in Georgia. We also became the first Atlanta sponsor of Neighborhood Link, an Internet-based community network enabling metropolitan-area neighborhood associations to create their own free, interactive Web sites.

We continue to work diligently with state and federal environmental regulators on key air and water quality issues. We will complete construction this year of a cooling tower at Plant Branch to help cool water discharges into Lake Sinclair. We've also announced plans to build cooling towers on Plants McDonough and Yates in an effort to improve oxygen levels in the Chattahoochee River. Last year, we began installing additional environmental controls on plants in north Georgia. The Selective Catalytic Reduction equipment will help the metro Atlanta area to comply with federally mandated ozone standards.

The year also brought unexpected challenges. In July, seven of our employees filed a lawsuit accusing Georgia Power of racial discrimination. We formed a Diversity Advisory Council to address long-term challenges for increasing the company's commitment to diversity. The council, with the assistance of dozens of employees, spent two months researching and studying the company's work environment, training and development, job selection processes and compensation practices, as well as reviewing other companies' best practices. In December, we approved 33 recommendations to help improve our company and we are now implementing those initiatives.

We are already dealing with the challenges of 2001, including preparations for a rate case to be filed with the Georgia Public Service Commission in July. It is an exciting time for our company, and I'm pleased to have the privilege of representing 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  
President and Chief Executive Officer  
March 23, 2001

## MANAGEMENT'S REPORT

Georgia Power Company 2000 Annual Report

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.

David M. Ratcliffe  
President and Chief  
Executive Officer

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.

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

## REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

### 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, 2000 and 1999, and the related statements of income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2000. 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 15-35) referred to above present fairly, in all material respects, the financial position of Georgia Power Company as of December 31, 2000 and 1999, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States.

Atlanta, Georgia  
February 28, 2001

# MANAGEMENT'S DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS AND FINANCIAL CONDITION

Georgia Power Company 2000 Annual Report

## RESULTS OF OPERATIONS

### Earnings

Georgia Power Company's 2000 earnings totaled \$559 million, representing an \$18 million (3.3 percent) increase over 1999. This earnings increase is 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. Georgia Power Company's 1999 earnings totaled \$541 million, representing a \$29 million (5.1 percent) decrease from 1998. This earnings decrease was primarily due to the recognition of interest income in 1998 as a result of the resolution of tax issues with the Internal Revenue Service (IRS). Earnings in 1999 from normal operations increased due primarily to lower accelerated depreciation under the GPSC retail rate order, sales growth, and decreased financing costs, partially offset by retail rate reductions under the new order and lower wholesale revenues.

### Revenues

Operating revenues in 2000 and the amount of change from the prior year are as follows:

	Amount 2000	Increase (Decrease) From Prior Year	
		2000	1999
		(in millions)	
Retail -			
Base revenues	\$3,119	\$84	\$(292)
Fuel cost recovery	1,198	183	44
<b>Total retail</b>	<b>4,317</b>	<b>267</b>	<b>(248)</b>
Sales for resale -			
Non-affiliates	298	88	(49)
Affiliates	96	20	(5)
<b>Total sales for resale</b>	<b>394</b>	<b>108</b>	<b>(54)</b>
Other operating revenues	160	39	21
<b>Total operating revenues</b>	<b>\$4,871</b>	<b>\$414</b>	<b>\$(281)</b>
Percent change		9.3%	(5.9)%

Retail base revenues of \$3.1 billion in 2000 increased \$84 million (2.8 percent) primarily due to a 4.9 percent increase in sales. Under the 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. Refunds will be made

to customers in 2001. Retail base revenues of \$3.0 billion in 1999 decreased \$292 million (8.8 percent) primarily due to retail rate reductions under the GPSC retail rate order. Pursuant to the GPSC retail rate order, in 1999 the Company also recorded \$79 million of revenue subject to refund for estimated earnings above 12.5 percent retail return on common equity. Revenue subject to refund is reflected in "Base revenues" in the chart above. The \$79 million in refunds were made to customers in 2000. See Note 3 to the financial statements under "Retail Rate Order" 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, 2000, the Company had \$132 million in underrecovered fuel costs. The Company currently plans to make a filing with the GPSC in early 2001 to establish a new fuel rate in order to better reflect current fuel cost and to collect the current underrecovered balance.

Wholesale revenues from sales to non-affiliated utilities increased in 2000 and decreased in 1999 as follows:

	2000	1999	1998
	(in millions)		
Outside service area -			
Long-term contracts	\$ 55	\$ 55	\$ 51
Other sales	162	74	93
Inside service area	81	81	115
<b>Total</b>	<b>\$298</b>	<b>\$210</b>	<b>\$259</b>

Revenues from long-term contracts outside the service area remained constant in 2000 and increased slightly in 1999 due to increased energy sales. See Note 7 to the financial statements for further information regarding these sales. Revenues from other sales outside the service area primarily represent wholesale sales from Plant Dahlberg which went into service during 2000 and increases in power marketing activities. These activities include the purchase and resale of energy. Consequently, changes in revenues are generally offset by corresponding changes in purchased power expense from non-affiliates. Wholesale revenues from customers within the service

**MANAGEMENT'S DISCUSSION AND ANALYSIS** (continued)  
Georgia Power Company 2000 Annual Report

area remained constant in 2000 but decreased in 1999 primarily due to a decrease in revenues under a power supply agreement with Oglethorpe Power Corporation (OPC).

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 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. In 1999, other operating revenues increased \$21 million or (21 percent) from the previous year due primarily to increased revenues from the rental of electric equipment and property.

Kilowatt-hour (KWH) sales for 2000 and the percent change by year were as follows:

	2000 KWH (in billions)	Percent Change	
		2000	1999
Residential	20.7	6.6%	(0.4)%
Commercial	25.6	8.1	3.7
Industrial	27.5	0.9	0.1
Other	0.6	3.2	1.5
Total retail	74.4	4.9	1.1
Sales for resale -			
Non-affiliates	6.5	27.7	(21.4)
Affiliates	2.4	35.6	(11.9)
Total sales for resale	8.9	29.8	(19.1)
Total sales	83.3	7.1	(1.0)

Residential and commercial sales increased 6.6 percent and 8.1 percent, respectively, 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. In 1999, residential sales decreased 0.4 percent due to moderate summer temperatures, while

commercial sales increased 3.7 percent due to strong regional economic growth. 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:

	2000	1999	1998
Total generation (billions of KWH)	73.6	69.3	69.1
Sources of generation (percent) --			
Coal	75.8	75.5	73.3
Nuclear	21.2	21.6	21.6
Hydro	0.8	1.0	2.6
Oil and gas	2.2	1.9	2.5
Average cost of fuel per net KWH generated (cents) --	1.39	1.34	1.36

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. Fuel expense increased 0.3 percent in 1999 due to a slight increase in fossil and nuclear generation and a decrease in generation from hydro plants, partially offset by a lower average cost of fuel.

Purchased power expense in 2000 increased \$206 million (53 percent) over the prior year due to higher retail energy demands and power marketing activities. The majority of the increase was offset by increases in retail fuel revenues and power marketing revenues and therefore did not affect earnings. As discussed above, the expense associated with energy purchased for power marketing activities is generally offset by revenue when resold. Purchased power expense decreased slightly in 1999.

Other operation and maintenance expenses in 2000 increased slightly over those in 1999. Increased line maintenance, customer assistance and sales expense and additional severance costs were partially offset by

decreased generating plant maintenance and decreased employee benefit provisions. Other operation and maintenance expenses increased 1.6 percent in 1999 primarily due to increased generating plant maintenance, partially offset by a reduction in the charges related to the implementation of a customer service system in 1998, decreased year 2000 readiness costs, and decreased employee benefit provisions.

Depreciation and amortization increased \$66 million in 2000 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. Depreciation and amortization decreased \$261 million in 1999 primarily due to higher depreciation charges recognized in 1998 under the prior GPSC accounting order and the completion in 1998 of the amortization of deferred Plant Vogtle costs.

Interest income decreased \$3 million in 2000 primarily due to decreased interest on temporary cash investments. Interest income decreased in 1999 primarily due to the 1998 recognition of \$73 million in interest income resulting from the resolution of tax issues with the IRS and the State of Georgia. Other, net decreased in 2000 due to an increase in charitable contributions. In 1999, other, net decreased due primarily to increased bad debt expense related to consumer energy efficiency improvement financing.

Interest expense, net increased in 2000 due to the issuance of an additional \$300 million in senior notes during 2000. Interest expense, net decreased in 1999 due primarily to the refinancing or retirement of securities. The Company refinanced or retired \$179 million and \$775 million of securities in 2000 and 1999, respectively. Distributions on preferred securities of subsidiary companies decreased \$7 million in 2000 due to the redemption of \$100 million of preferred securities in December 1999. Distributions on preferred securities of subsidiary companies increased \$11 million in 1999 due to the issuance of additional mandatorily redeemable preferred securities in January 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 life. 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**

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.

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 January 1, 1999, the Company began operating under a new three-year retail rate order. The Company's earnings are evaluated against a retail return on common equity range of 10 percent to 12.5 percent, with required rate reductions of \$262 million on an annual basis effective in 1999 and an additional \$24 million effective in 2000. The order provides 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 will be applied to rate reductions, with the remaining one-third retained by the Company. Pursuant to the GPSC retail rate order, in 2000 and 1999, the Company recorded \$85 million in accelerated amortization of regulatory assets. In 2000, the Company also recorded the additional \$50 million of accelerated amortization. The accelerated amortization is recorded in a regulatory liability account as mandated by the GPSC. In addition, the Company recorded \$44 million and \$79 million of revenue subject to refund for estimated earnings above 12.5 percent in 2000 and 1999, respectively. Refunds applicable to 1999 were made to customers in 2000. The Company will file a general rate case on July 2, 2001 in response to which the GPSC

would be expected to determine whether the retail rate order should be continued, modified, or discontinued. See Note 3 to the financial statements under "Retail Rate Order" for additional information.

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. Assuming normal weather, retail sales growth from 2000 is projected to be approximately 2.4 percent annually on average during 2001 through 2003.

The Company has entered into purchase power agreements which will result in higher capacity and operating and maintenance payments in future years. See Note 4 to the financial statements under "Purchased Power Commitments" for additional information.

The Company is constructing two 566 megawatt combined cycle units at Plant Wansley to begin operation in 2002. These units have been certified by the GPSC to serve the Company's retail customers for approximately seven years. Savannah Electric will have the rights to 200 megawatts of capacity from these units for the same seven-year period.

The Company is also constructing a 571 megawatt combined cycle unit at Plant Goat Rock to begin operation in 2002, and a 610 megawatt combined cycle unit at Plant Goat Rock to begin operation in 2003. The power from these units will initially be sold into the wholesale market when they begin operation. The Company has filed with the GPSC for certification of these units to begin serving the Company's retail customers in 2003 and 2004, respectively, for a term of seven years each.

In addition to seeking certification of Plant Goat Rock, the Company is also seeking certification of a seven year commitment to 615 megawatts beginning in 2004 at Plant Autaugaville to serve its retail customers. Plant Autaugaville is currently under construction by Alabama Power.

Further, the Company is constructing Plant Dahlberg, a ten unit, 800 megawatt combustion turbine peaking

power plant that will serve the wholesale market. Units one through eight began operation in May 2000; units nine and ten are expected to begin operation in June 2001. The Company has entered into wholesale contracts to sell all 800 megawatts of capacity. These contracts cover substantially all of the output of the plant for the first five years. Because these units are dedicated to the wholesale market, retail rates will not be affected.

The Company is aggressively working to maintain and expand its share of wholesale sales in the Southeastern power markets. In January 2001, Southern Company announced the formation of a new subsidiary, Southern Power Company (SPC). SPC will own, manage, and finance wholesale generating assets in the Southeast. Energy from its assets will be marketed to wholesale customers under the Southern Company name. The current plan is for Georgia Power and Alabama Power to transfer Plant Dahlberg and the units under construction at Plants Wansley, Goat Rock, and Autaugaville to SPC in 2001. The Company will enter into purchased power capacity agreements with SPC for power from the units at Plants Wansley, Goat Rock, and Autaugaville to serve the Company's retail customers.

In accordance with Financial Accounting Standards Board (FASB) Statement No. 87, Employers' Accounting for Pensions, the Company recorded non-cash income of approximately \$59 million in 2000. Pension plan income in 2001 is expected to be less as a result of plan amendments. Future pension income is dependent on several factors including trust earnings and changes to the plan. For additional information see Note 2 to the financial statements.

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.

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. Although the Energy Act does not permit retail customer access, it was a major

catalyst for the current restructuring and consolidation taking place within the utility industry.

On December 20, 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. After participating in regional conferences with customers and other members of the public to discuss the formation of RTOs, utilities were required to make a filing with the FERC. On October 16, 2000, Southern Company and its five integrated Southeast utilities, including the Company, filed with the FERC a proposal for the creation of an RTO. The proposal is for the formation of a for-profit company that would have control of the bulk power transmission system of participating utilities. Participants would have the option to either maintain their ownership, divest, sell, or lease their assets to the proposed RTO. If the FERC accepts the proposal as filed, the creation of the RTO is not expected to have a material impact on the financial statements of the Company. However, the ultimate outcome of this matter cannot now be determined.

The Company continues to 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. Numerous federal and state initiatives are in varying stages to promote wholesale and retail competition across the nation. Among other things, these initiatives allow customers to choose their electricity provider. As these initiatives materialize, the structure of the utility industry could radically change. 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 the GPSC has held workshops to discuss retail competition and industry restructuring, there has been no proposed or enacted legislation to date in Georgia. Enactment would require numerous issues to be resolved, including significant ones relating to transmission pricing and recovery of costs. The GPSC continues its assessment of the range of potential stranded costs. The inability of the Company to recover all its costs, including the regulatory assets described in Note 1 to the financial statements, could have a material effect on the financial condition of the Company. The Company is attempting to reduce regulatory assets through the GPSC retail rate order. See

Note 3 to the financial statements under "Retail Rate Order" for additional information.

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 have been impaired. See Note 1 to the financial statements under "Regulatory Assets and Liabilities" for additional information.

The staff of the Securities and Exchange Commission (SEC) has questioned certain of the current accounting practices of the electric utility industry - including the Company's - regarding the recognition, measurement, and classification in the financial statements of decommissioning costs for nuclear generating facilities. In response to these questions, the FASB is reviewing the accounting for liabilities related to the retirement of long-lived assets, including nuclear decommissioning. If the FASB issues new accounting rules, the estimated costs of retiring the Company's nuclear and other facilities may be required to be recorded as liabilities in the Balance Sheets. Also, the annual provisions for such costs could change. Because of the Company's current ability to recover asset retirement costs through rates, these changes would not have a significant adverse effect on results of operations. See Note 1 to the financial statements under "Depreciation and Nuclear Decommissioning" for additional information.

### **Exposure to Market Risks**

Due to cost-based rate regulation, the Company currently has limited exposure to market volatility in interest rates, commodity fuel prices and prices of electricity. (See the discussion above for potential changes in industry structure.) To mitigate residual risks relative to movements in electricity prices, the Company enters into fixed price contracts for the purchase and sale of electricity through the wholesale electricity market. Realized gains and losses are recognized in the income statement as incurred. At December 31, 2000, exposure from these activities was not material to the Company's financial position, results of operations, or cash flows. Also, based on the Company's overall interest rate exposure at December 31, 2000, a near-term 100 basis

point change in interest rates would not materially affect the financial statements.

### **New Accounting Standard**

In June 2000, the FASB issued Statement No. 138, an amendment of Statement No. 133, Accounting for Derivative Instruments and Hedging Activities. Statement No. 133, as amended, establishes accounting and reporting standards for derivative instruments and for hedging activities. Statement No. 133 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.

Substantially all of the Company's bulk energy purchases and sales meet the definition of a derivative under Statement No. 133. In many cases, these transactions meet the normal purchase and sale exception and the related contracts will continue to be accounted for under the accrual method. Certain of these instruments qualify as cash flow hedges resulting in the deferral of related gains and losses in other comprehensive income until the hedged transactions occur. Any ineffectiveness will be recognized currently in net income. However, others will be required to be marked to market through current period income.

The Company adopted the provisions of Statement No. 133 effective January 1, 2001. The impact on net income was immaterial. The application of the new rules is still evolving and further guidance from the FASB is expected, which could additionally impact the Company's financial statements.

## **FINANCIAL CONDITION**

### **Plant Additions**

In 2000, gross utility plant additions were \$1.1 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.

### **Financing Activities**

In 2000, the Company's financing costs increased due to the issuance of new debt during the year. New issues during 1998 through 2000 totaled \$1.5 billion and retirement or repayment of higher-cost securities totaled \$1.7 billion.

Special purpose subsidiaries of the Company have issued mandatorily redeemable preferred securities. See Note 9 to the financial statements under "Preferred Securities" for additional information.

Composite financing rates for long-term debt, preferred stock, and preferred securities for the years 1998 through 2000, as of year-end, were as follows:

	<u>2000</u>	<u>1999</u>	<u>1998</u>
Composite interest rate on long-term debt	<b>5.90%</b>	5.48%	5.64%
Composite preferred stock dividend rate	<b>4.60</b>	4.60	5.52
Composite preferred securities dividend rate	<b>7.49</b>	7.49	7.89

### **Liquidity and Capital Requirements**

Cash provided from operations decreased by \$135 million in 2000, primarily due to higher fuel and purchased power expenses related to increased energy demands.

The Company estimates that construction expenditures for the years 2001 through 2003 will total \$1.6 billion, \$1.3 billion, and \$0.8 billion, respectively. If the Company transfers wholesale generation assets to SPC in 2001 as contemplated, construction expenditures for the years 2001 through 2003 will total \$1.0 billion, \$0.9 billion, and \$0.7 billion, respectively. Investments in additional combustion turbine and combined cycle generating units, transmission and distribution facilities, enhancements to existing generating plants, and equipment to comply with environmental requirements are planned.

Cash requirements for redemptions announced and maturities of long-term debt are expected to total \$581 million during 2001 through 2003.

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 is \$30 million each year in 2001, 2002, and 2003. 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, if needed, by the issuance of new debt and equity securities, term loans, and short-term borrowings. 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 2001. See Note 9 to the financial statements under "Bank Credit Arrangements" for additional information.

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 the later securities has been steadily declining during the last four years.

If the Company were to choose to issue new first mortgage bonds or preferred stock once again, it would be required to meet certain coverage requirements.

## **ENVIRONMENTAL ISSUES**

### **Clean Air Act**

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. Specific reductions in sulfur dioxide and nitrogen oxide emissions from fossil-fired generating plants are required in two phases. Phase I compliance began in 1995 and some 50 generating units within Southern Company's subsidiaries were brought into compliance with Phase I requirements.

Southern Company's subsidiaries, including the Company, achieved Phase I sulfur dioxide compliance at the affected units by switching to low-sulfur coal, which required 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.

The one-hour ozone non-attainment standards for the Atlanta area have been set and must be implemented in May 2003. Seven generating plants will be affected in the Atlanta area. Additional construction expenditures for the Company's compliance with these new rules are currently estimated at approximately \$705 million.

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.

### **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 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. 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 unless such costs can be recovered through regulated rates.

### **Other Environmental Issues**

In July 1997, the 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 recently dismissed certain challenges but 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 will address other legal challenges to these standards in mid-2001. If the standards are eventually upheld, implementation could be required by 2007 to 2010.

In September 1998, the EPA issued the final regional nitrogen oxide reduction rules to the states for implementation. Compliance is required by May 31, 2004. The final rule affects 21 states, including Georgia.

In December 2000, the EPA completed its utility study for mercury and other hazardous air pollutants (HAPS) and issued a determination that an emission control program for mercury and, perhaps, other HAPS is warranted. The program is to be developed over the next four years under the Maximum Achievable Control Technology (MACT) provisions of the Clean Air Act. This determination is being challenged in the courts. 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 would likely be required around 2010. Litigation of the BART rules is probable in the near future.

Implementation of the final state rules for these initiatives could require substantial further reductions in nitrogen oxide, sulfur dioxide, 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. Reviews by the new administration in Washington, D.C. add to the uncertainties associated with BART guidance and the MACT determination for mercury and other HAPS.

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 costs and has recognized in the financial statements costs to clean up known sites. These costs for the Company amounted to \$4 million, \$4 million, and \$6 million in 2000, 1999, and 1998, respectively. Additional sites may require environmental remediation for which the Company may be liable for a portion of or all 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 a site in Brunswick, Georgia,

and the status of sites listed on the State of Georgia's hazardous site inventory.

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; water intake restrictions; and hazardous waste disposal requirements. The impact of any new standards will depend on the development and implementation of applicable regulations.

Several major pieces of environmental legislation are being 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 2000 Annual Report contains forward-looking and historical information. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "predicts," "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 extent and timing of the entry of additional competition in the Company's markets; potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial; internal restructuring or other restructuring options, that may be pursued by the Company; state and federal rate regulation in the United States; political, legal and economic conditions and developments in the United States; financial market conditions and the results of financing efforts; the impact of fluctuations in commodity prices, interest rates and customer demand; weather and other natural phenomena; the ability of the Company to obtain additional generating capacity at competitive prices; and other factors discussed elsewhere herein and in other reports (including Form 10-K) filed from time to time by the Company with the SEC.

**STATEMENTS OF INCOME**  
**For the Years Ended December 31, 2000, 1999, and 1998**  
**Georgia Power Company 2000 Annual Report**

	2000	1999	1998
		<i>(in thousands)</i>	
<b>Operating Revenues:</b>			
Retail sales	\$4,317,338	\$4,050,088	\$4,298,217
Sales for resale --			
Non-affiliates	297,643	210,104	259,234
Affiliates	96,150	76,426	81,606
Other revenues	159,487	120,057	99,196
<b>Total operating revenues</b>	<b>4,870,618</b>	<b>4,456,675</b>	<b>4,738,253</b>
<b>Operating Expenses:</b>			
Operation --			
Fuel	1,017,878	919,876	917,119
Purchased power --			
Non-affiliates	356,189	214,573	229,960
Affiliates	239,815	174,989	161,003
Other	795,458	784,359	819,589
Maintenance	404,189	411,983	358,218
Depreciation and amortization	619,094	552,966	813,802
Taxes other than income taxes	204,527	202,853	204,623
Write down of Rocky Mountain plant	-	-	33,536
<b>Total operating expenses</b>	<b>3,637,150</b>	<b>3,261,599</b>	<b>3,537,850</b>
<b>Operating Income</b>	<b>1,233,468</b>	<b>1,195,076</b>	<b>1,200,403</b>
<b>Other Income (Expense):</b>			
Interest income	2,629	5,583	79,578
Equity in earnings of unconsolidated subsidiaries	3,051	2,721	3,735
Other, net	(50,495)	(47,986)	(38,277)
<b>Earnings Before Interest and Income Taxes</b>	<b>1,188,653</b>	<b>1,155,394</b>	<b>1,245,439</b>
<b>Interest Charges and Other:</b>			
Interest expense, net	208,868	194,869	216,313
Distributions on preferred securities of subsidiaries	59,104	65,774	54,327
<b>Total interest charges and other, net</b>	<b>267,972</b>	<b>260,643</b>	<b>270,640</b>
<b>Earnings Before Income Taxes</b>	<b>920,681</b>	<b>894,751</b>	<b>974,799</b>
Income taxes	360,587	351,639	398,632
<b>Net Income</b>	<b>560,094</b>	<b>543,112</b>	<b>576,167</b>
<b>Dividends on Preferred Stock</b>	<b>674</b>	<b>1,729</b>	<b>5,939</b>
<b>Net Income After Dividends on Preferred Stock</b>	<b>\$ 559,420</b>	<b>\$ 541,383</b>	<b>\$ 570,228</b>

The accompanying notes are an integral part of these statements.

**BALANCE SHEETS**

At December 31, 2000 and 1999

Georgia Power Company 2000 Annual Report

<b>Assets</b>	<b>2000</b>	<b>1999</b>
		<i>(in thousands)</i>
<b>Current Assets:</b>		
Cash and cash equivalents	\$ 29,370	\$ 34,660
Receivables --		
Customer accounts receivable	465,249	401,773
Unrecovered retail fuel clause revenue	131,623	36,388
Other accounts and notes receivable	156,143	102,544
Affiliated companies	13,312	16,006
Accumulated provision for uncollectible accounts	(5,100)	(7,000)
Fossil fuel stock, at average cost	99,463	126,298
Materials and supplies, at average cost	263,609	253,894
Other	97,515	63,990
<b>Total current assets</b>	<b>1,251,184</b>	<b>1,028,553</b>
<b>Property, Plant, and Equipment:</b>		
In service	16,469,706	15,798,624
Less accumulated provision for depreciation	6,914,512	6,538,574
	9,555,194	9,260,050
Nuclear fuel, at amortized cost	120,570	119,288
Construction work in progress (Note 4)	652,264	425,975
<b>Total property, plant, and equipment</b>	<b>10,328,028</b>	<b>9,805,313</b>
<b>Other Property and Investments:</b>		
Equity investments in unconsolidated subsidiaries (Note 4)	25,485	25,024
Nuclear decommissioning trusts	375,666	371,914
Other	33,829	33,766
<b>Total other property and investments</b>	<b>434,980</b>	<b>430,704</b>
<b>Deferred Charges and Other Assets:</b>		
Deferred charges related to income taxes (Note 8)	565,982	590,893
Prepaid pension costs	205,113	145,801
Debt expense, being amortized	53,748	55,824
Premium on reacquired debt, being amortized	173,610	184,331
Other	120,964	120,441
<b>Total deferred charges and other assets</b>	<b>1,119,417</b>	<b>1,097,290</b>
<b>Total Assets</b>	<b>\$13,133,609</b>	<b>\$12,361,860</b>

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

**BALANCE SHEETS**

At December 31, 2000 and 1999

Georgia Power Company 2000 Annual Report

<b>Liabilities and Stockholder's Equity</b>	<b>2000</b>	<b>1999</b>
	<i>(in thousands)</i>	
<b>Current Liabilities:</b>		
Securities due within one year (Note 9)	\$ 1,808	\$ 155,772
Notes payable	703,839	636,241
Accounts payable --		
Affiliated	117,168	76,591
Other	397,550	346,785
Customer deposits	78,540	74,695
Taxes accrued --		
Income taxes	5,151	7,914
Other	137,511	127,414
Interest accrued	47,244	58,665
Vacation pay accrued	38,865	38,143
Other	153,400	153,767
<b>Total current liabilities</b>	<b>1,681,076</b>	<b>1,675,987</b>
<b>Long-term debt</b> (See accompanying statements)	<b>3,041,939</b>	<b>2,688,358</b>
<b>Deferred Credits and Other Liabilities:</b>		
Accumulated deferred income taxes (Note 8)	2,182,783	2,202,565
Deferred credits related to income taxes (Note 8)	247,067	267,083
Accumulated deferred investment tax credits (Note 8)	352,282	367,114
Employee benefits provisions	177,444	181,529
Other	397,655	236,812
<b>Total deferred credits and other liabilities</b>	<b>3,357,231</b>	<b>3,255,103</b>
<b>Company obligated mandatorily redeemable preferred securities of subsidiary trusts holding company junior subordinated notes</b> (See accompanying statements)	<b>789,250</b>	<b>789,250</b>
<b>Cumulative preferred stock</b> (See accompanying statements)	<b>14,569</b>	<b>14,952</b>
<b>Common stockholder's equity</b> (See accompanying statements)	<b>4,249,544</b>	<b>3,938,210</b>
<b>Total Liabilities and Stockholder's Equity</b>	<b>\$13,133,609</b>	<b>\$12,361,860</b>

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

**STATEMENTS OF CAPITALIZATION**  
**At December 31, 2000 and 1999**  
**Georgia Power Company 2000 Annual Report**

	2000	1999	2000	1999
	<i>(in thousands)</i>		<i>(percent of total)</i>	
<b>Long-Term Debt:</b>				
First mortgage bonds --				
<u>Maturity</u>	<u>Interest Rates</u>			
March 1, 2000	6.00%	\$ -	\$ 100,000	
April 1, 2003	6.625%	<b>200,000</b>	200,000	
August 1, 2003	6.35%	<b>75,000</b>	75,000	
2005	6.07%	<b>10,000</b>	10,000	
2008	6.875%	<b>50,000</b>	50,000	
2025	7.70%	<b>57,000</b>	57,000	
<b>Total first mortgage bonds</b>		<b>392,000</b>	492,000	
Senior notes -- (Note 9)				
Variable rate (6.71375% at 1/1/01) due February 22, 2002		<b>300,000</b>	-	
5.50% due December 1, 2005		<b>150,000</b>	150,000	
6.60% due December 31, 2038		<b>200,000</b>	200,000	
6.625% due March 31, 2039		<b>100,000</b>	100,000	
6.875% due December 31, 2047		<b>145,000</b>	145,000	
<b>Total senior notes payable</b>		<b>895,000</b>	595,000	
Other long-term debt -- (Note 9)				
Pollution control revenue bonds --				
<u>Maturity</u>	<u>Interest Rates</u>			
2000	4.375%	-	50,000	
2005	5.00%	<b>57,000</b>	57,000	
2011	Variable (5.10% at 1/1/01)	<b>10,450</b>	10,450	
2018-2019	6.00% to 6.25%	<b>13,100</b>	13,100	
2021-2025	5.40% to 6.75%	<b>308,660</b>	337,385	
2022-2025	Variable (4.85% to 5.35% at 1/1/01)	<b>622,075</b>	622,075	
2026-2030	Variable (5.00% to 5.10% at 1/1/01)	<b>206,180</b>	206,180	
2030	4.53%	<b>78,725</b>	-	
2032-2034	Variable (5.0% to 5.30% at 1/1/01)	<b>140,000</b>	140,000	
2034	5.25% to 5.45%	<b>238,000</b>	238,000	
<b>Total other long-term debt</b>		<b>1,674,190</b>	1,674,190	
Capital lease obligations (Note 9)		<b>85,179</b>	85,851	
Unamortized debt discount, net		<b>(2,622)</b>	(2,911)	
<b>Total long-term debt (annual interest requirement -- \$179.6 million)</b>		<b>3,043,747</b>	2,844,130	
Less amount due within one year (Note 9)		<b>1,808</b>	155,772	
<b>Total long-term debt excluding amount due within one year</b>		<b>\$ 3,041,939</b>	\$ 2,688,358	<b>37.6 %</b> 36.2 %

**STATEMENTS OF CAPITALIZATION (continued)**

At December 31, 2000 and 1999

Georgia Power Company 2000 Annual Report

	2000	1999	2000	1999
	<i>(in thousands)</i>		<i>(percent of total)</i>	
<b>Company Obligated Mandatorily</b>				
<b>Redeemable Preferred Securities (Note 9):</b>				
\$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	9.7	10.6
<b>Cumulative Preferred Stock, without par value:</b>				
Authorized -- 55,000,000 shares				
Outstanding -- 145,689 shares at December 31, 2000				
Outstanding -- 149,520 shares at December 31, 1999				
\$100 stated value --				
4.60%	14,569	14,952		
Total cumulative preferred stock (annual dividend requirement -- \$0.7 million)	14,569	14,952	0.2	0.2
<b>Common Stockholder's Equity:</b>				
Common stock, without par value --				
Authorized -- 15,000,000 shares				
Outstanding -- 7,761,500 shares	344,250	344,250		
Paid-in capital	2,117,497	1,815,983		
Premium on preferred stock	40	40		
Retained earnings (Note 9)	1,787,757	1,777,937		
Total common stockholder's equity (See accompanying statements)	4,249,544	3,938,210	52.5	53.0
<b>Total Capitalization</b>	<b>\$ 8,095,302</b>	<b>\$ 7,430,770</b>	<b>100.0 %</b>	<b>100.0 %</b>

The accompanying notes are an integral part of these statements.

## STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

For the Years Ended December 31, 2000, 1999, and 1998

Georgia Power Company 2000 Annual Report

	Common Stock	Paid-In Capital	Premium on Preferred Stock	Retained Earnings	Total
	<i>(in thousands)</i>				
<b>Balance at January 1, 1998</b>	\$344,250	\$1,929,971	\$160	\$1,745,347	\$4,019,728
Net income after dividends on preferred stock	-	-	-	570,228	570,228
Capital distributions to parent company	-	(270,000)	-	-	(270,000)
Capital contributions from parent company	-	235	-	-	235
Cash dividends on common stock	-	-	-	(536,600)	(536,600)
Preferred stock transactions, net	-	-	(2)	583	581
<b>Balance at December 31, 1998</b>	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)
<b>Balance at December 31, 1999</b>	344,250	1,815,983	40	1,777,937	3,938,210
Net income after dividends on preferred stock	-	-	-	<b>559,420</b>	<b>559,420</b>
Capital contributions from parent company	-	<b>301,514</b>	-	-	<b>301,514</b>
Cash dividends on common stock	-	-	-	<b>(549,600)</b>	<b>(549,600)</b>
<b>Balance at December 31, 2000</b>	<b>\$344,250</b>	<b>\$2,117,497</b>	<b>\$40</b>	<b>\$1,787,757</b>	<b>\$4,249,544</b>

The accompanying notes are an integral part of these statements.

## STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2000, 1999, and 1998  
Georgia Power Company 2000 Annual Report

	2000	1999	1998
		<i>(in thousands)</i>	
<b>Operating Activities:</b>			
Net income	\$ 560,094	\$ 543,112	\$ 576,167
Adjustments to reconcile net income to net cash provided from operating activities --			
Depreciation and amortization	712,960	663,878	867,637
Deferred income taxes and investment tax credits, net	(28,961)	(34,930)	(93,005)
Other, net	(51,501)	(42,179)	40,396
Changes in certain current assets and liabilities --			
Receivables, net	(108,621)	21,665	(25,453)
Fossil fuel stock	26,835	(22,165)	(8,066)
Materials and supplies	(9,715)	(10,417)	(3,090)
Accounts payables	64,412	13,095	47,862
Energy cost recovery, retail	(95,235)	(26,862)	(7,649)
Other	(9,092)	90,788	6,997
Net cash provided from operating activities	1,061,176	1,195,985	1,401,796
<b>Investing Activities:</b>			
Gross property additions	(1,078,163)	(790,464)	(499,053)
Other	(5,450)	(27,454)	67,031
Net cash used for investing activities	(1,083,613)	(817,918)	(432,022)
<b>Financing Activities:</b>			
Increase (decrease) in notes payable, net	67,598	295,389	(25,378)
Proceeds --			
Senior notes	300,000	100,000	495,000
Pollution control bonds	78,725	238,000	89,990
Preferred securities	-	200,000	-
Capital contributions from parent company	301,514	155,777	235
Retirements --			
First mortgage bonds	(100,000)	(404,000)	(558,250)
Pollution control bonds	(78,725)	(235,000)	(89,990)
Preferred securities	-	(100,000)	-
Preferred stock	(383)	(36,231)	(106,064)
Capital distributions to parent company	-	-	(270,000)
Payment of preferred stock dividends	(751)	(984)	(9,137)
Payment of common stock dividends	(549,600)	(543,000)	(536,600)
Other	(1,231)	(29,630)	(26,641)
Net cash provided from (used for) financing activities	17,147	(359,679)	(1,036,835)
<b>Net Change in Cash and Cash Equivalents</b>	<b>(5,290)</b>	<b>18,388</b>	<b>(67,061)</b>
<b>Cash and Cash Equivalents at Beginning of Year</b>	<b>34,660</b>	<b>16,272</b>	<b>83,333</b>
<b>Cash and Cash Equivalents at End of Year</b>	<b>\$ 29,370</b>	<b>\$ 34,660</b>	<b>\$ 16,272</b>
<b>Supplemental Cash Flow Information:</b>			
Cash paid during the year for --			
Interest (net of amount capitalized)	\$ 265,373	\$ 247,050	\$ 269,524
Income taxes (net of refunds)	392,310	394,457	480,318

The accompanying notes are an integral part of these statements.

## NOTES TO FINANCIAL STATEMENTS

Georgia Power Company 2000 Annual Report

### 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

#### General

The Company is a wholly owned subsidiary of Southern Company, which is the parent company of five integrated Southeast utilities, Southern Company Services (SCS), the system service company, Southern Communications Services (Southern LINC), Mirant Corporation (formerly Southern Energy), Southern Nuclear Operating Company (Southern Nuclear), Southern Company Energy Solutions, and other direct and indirect subsidiaries. The integrated Southeast utilities (Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Savannah Electric and Power Company) provide electric service in four states. Contracts among the integrated Southeast utilities -- related to jointly owned generating facilities, interconnecting transmission lines, and the exchange of electric power -- are regulated by the Federal Energy Regulatory Commission (FERC) or the Securities and Exchange Commission (SEC). SCS provides, at cost, specialized services to Southern Company and subsidiary companies. Southern LINC provides digital wireless communications services to the subsidiary companies and also markets these services to the public within the Southeast. Southern Company Energy Solutions develops new business opportunities related to energy products and services. Southern Nuclear provides services to Southern Company's nuclear power plants. Mirant Corporation acquires, develops, builds, owns, and operates power production and delivery facilities and provides a broad range of energy-related services to utilities and industrial companies in selected countries around the world. Mirant Corporation's businesses include independent power projects, integrated utilities, a distribution company, and energy trading and marketing businesses outside the Southeastern United States.

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.

#### Related-Party 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 \$269 million, \$253 million, and \$251 million during 2000, 1999, and 1998, 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, \$270 million, and \$269 million during 2000, 1999, and 1998, respectively.

#### 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. Pursuant to the terms of the GPSC retail rate order, the Company recorded \$135 million and \$85 million in 2000 and 1999, respectively, of accelerated cost recovery of regulatory assets which have been

recorded on the balance sheet as a regulatory liability. See Note 3 under "Retail Rate Order" for additional information. Regulatory assets and (liabilities) reflected in the Company's Balance Sheets at December 31 relate to the following:

	2000	1999
	(in millions)	
Deferred income taxes	\$ 566	\$ 591
Deferred income tax credits	(247)	(267)
Premium on reacquired debt	174	184
Corporate building lease	55	54
Vacation pay	49	47
Postretirement benefits	30	33
Department of Energy assessments	21	24
Deferred nuclear outage costs	28	26
Accelerated cost recovery	(220)	(85)
Interest, accelerated cost recovery	(10)	-
Other, net	23	3
<b>Total</b>	<b>\$ 469</b>	<b>\$ 610</b>

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.

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.

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.

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 2000, \$74 million in 1999, and \$74 million in 1998. The Company has a contract with the U.S. Department of Energy (DOE) that provides for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent fuel in January 1998 as required by the contracts, and the Company is pursuing legal remedies against the government for breach of contract. Effective June 2000, the on-site dry storage facility for Plant Hatch became operational. Sufficient capacity is believed available to continue dry storage operations at Plant Hatch through the life of the plant. Sufficient fuel storage capacity currently is available at Plant Vogtle to maintain full-core discharge capability for both units into the year 2014.

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, 2000 to be approximately \$19 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 2000 and 1999, and 3.2 percent in 1998. In addition, pursuant to a GPSC retail rate order, the Company recorded accelerated depreciation of electric plant of \$304 million in 1998. Total accelerated depreciation recorded under the GPSC retail rate order was \$467 million. These charges are recorded in the accumulated provision for depreciation. 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. Amounts previously recorded in internal reserves are being transferred into the external trust funds over a set period of time as ordered by the GPSC. 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
<b>Total</b>	<b>\$523</b>	<b>\$468</b>
(in millions)		
Ultimate costs:		
Radiated structures	\$1,004	\$1,468
Non-radiated structures	79	166
<b>Total</b>	<b>\$1,083</b>	<b>\$1,634</b>

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. The Company has filed with the NRC an application requesting a 20-year renewal of the licenses for both units at Plant Hatch which would permit the operation of both units until 2034.

Annual provisions for nuclear decommissioning expense are based on an annuity method as approved by the GPSC. The amounts expensed in 2000 and fund balances as of December 31, 2000 were:

	Plant Hatch	Plant Vogtle
(in millions)		
Amount expensed in 2000	\$ 19	\$ 9
(in millions)		
Accumulated provisions:		
External trust funds, at fair value	\$230	\$146
Internal reserves	20	12
<b>Total</b>	<b>\$250</b>	<b>\$158</b>

Effective January 1, 1999, the GPSC increased the annual provision for decommissioning expenses to

\$28 million from \$20 million in 1998. This amount is based on the NRC generic estimate to decommission the radioactive portion of the facilities as of 1997 of \$526 million and \$438 million for Plants Hatch and Vogtle, respectively. The ultimate costs associated with the 1997 NRC minimum funding requirements are \$1.1 billion and \$1.3 billion for Plants Hatch and Vogtle, respectively. Significant assumptions include an estimated inflation rate of 3.6 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.

### **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 2000, 1999, and 1998, the average AFUDC rates were 6.74 percent, 5.61 percent, and 6.71 percent, respectively. AFUDC, net of taxes, as a percentage of net income after dividends on preferred stock, was less than 2.0 percent for 2000, 1999 and 1998.

### **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.

### **Financial Instruments**

The Company has a firm commitment that requires payment in euros. As a hedge against fluctuations in the exchange rate for euros, the Company entered into forward currency swaps. The notional amount is 15.9 million euros maturing in 2001 through 2002. At December 31, 2000, the unrecognized gain on these swaps was approximately \$1.3 million.

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:		
<b>At December 31, 2000</b>	<b>\$2,959</b>	<b>\$2,912</b>
At December 31, 1999	\$2,758	\$2,604
Preferred securities:		
<b>At December 31, 2000</b>	<b>\$789</b>	<b>\$761</b>
At December 31, 1999	\$789	\$680

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, trustee 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 FERC. In late 2000, the Company adopted several pension and postretirement

**NOTES** (continued)  
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benefits plan changes that had the effect of increasing benefits to both current and future retirees. The effects of these changes will be to increase annual pension and postretirement benefits costs by approximately \$10 million and \$6 million, respectively. 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:

	2000	1999
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	
	2000	1999
	(in millions)	
Balance at beginning of year	\$1,205	\$1,217
Service cost	32	33
Interest cost	88	80
Benefits paid	(58)	(57)
Actuarial gain and employee transfers	(14)	(68)
Balance at end of year	\$1,253	\$1,205

	Plan Assets	
	2000	1999
	(in millions)	
Balance at beginning of year	\$2,107	\$1,859
Actual return on plan assets	385	313
Benefits paid	(58)	(57)
Employee transfers	30	(8)
Balance at end of year	\$2,464	\$2,107

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

	2000	1999
	(in millions)	
Funded status	\$1,211	\$ 902
Unrecognized transition obligation	(26)	(30)
Unrecognized prior service cost	38	41
Unrecognized net actuarial gain	(1,018)	(767)
Prepaid asset recognized in the Balance Sheets	\$ 205	\$ 146

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

	2000	1999	1998
	(in millions)		
Service cost	\$ 32	\$ 33	\$ 30
Interest cost	88	80	82
Expected return on plan assets	(151)	(137)	(127)
Recognized net actuarial gain	(27)	(17)	(20)
Net amortization	(1)	(1)	(1)
Net pension income	\$ (59)	\$ (42)	\$ (36)

**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	
	2000	1999
	(in millions)	
Balance at beginning of year	\$438	\$464
Service cost	7	8
Interest cost	36	30
Benefits paid	(21)	(19)
Actuarial gain and employee transfers	(28)	(45)
Amendments	63	-
Balance at end of year	\$495	\$438

	Plan Assets	
	2000	1999
	(in millions)	
Balance at beginning of year	\$177	\$150
Actual return on plan assets	12	11
Employer contributions	30	35
Benefits paid	(21)	(19)
Balance at end of year	\$198	\$177

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

	2000	1999
	(in millions)	
Funded status	\$(297)	\$(261)
Unrecognized transition obligation	113	122
Unrecognized prior service cost	60	-
Unrecognized gain	(13)	-
Unrecognized net actuarial loss	-	10
Fourth quarter contributions	27	14
Accrued liability recognized in the Balance Sheets	\$(110)	\$(115)

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

	2000	1999	1998
	(in millions)		
Service cost	\$ 7	\$ 8	\$ 7
Interest cost	36	30	32
Expected return on plan assets	(16)	(10)	(9)
Recognized net actuarial loss	-	1	1
Net amortization	12	9	9
Net postretirement cost	\$ 39	\$ 38	\$ 40

An additional assumption used in measuring the accumulated postretirement benefit obligations was a weighted average medical care cost trend rate of 7.29 percent for 2000, decreasing gradually to 5.50 percent through the year 2005, 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, 2000 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	\$ 39	\$ 34
Service and interest costs	3	3

### Employee Savings Plan

The Company also 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 2000, 1999, and 1998 were \$15 million, \$15 million, and \$14 million, respectively.

### 3. CONTINGENCIES & REGULATORY MATTERS

#### Retail Rate Order

On December 18, 1998, the GPSC approved a three-year retail rate order for the Company ending December 31, 2001. Under the terms of the order, earnings are evaluated against a retail return on common equity range of 10 percent to 12.5 percent. Retail rates were decreased by \$262 million on an annual basis effective January 1, 1999, and by an additional \$24 million effective January 1, 2000. The order further provides 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 will be applied to rate reductions, with the remaining one-third retained by the Company. Pursuant to the order, in 2000 and 1999, the Company recorded \$85 million each year in accelerated amortization of regulatory assets. In 2000, the Company also recorded the additional \$50 million of accelerated amortization. The accelerated amortization is recorded in a regulatory liability account and, as mandated by the GPSC, the Company recorded \$10 million of interest on the amounts in the regulatory liability account. In addition, the Company recorded \$44 million and \$79 million of revenue subject to refund for estimated earnings above 12.5 percent retail return on common equity in 2000 and 1999, respectively. Refunds applicable to 1999 were made to customers in 2000. The estimated 2000 refund is included in other current liabilities on the Balance Sheet. The Company will file a

general rate case on July 2, 2001, in response to which the GPSC would be expected to determine whether the rate order should be continued, modified, or discontinued.

### **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 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.

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 unless such costs can be recovered through regulated rates.

### **Other Environmental Contingencies**

In January 1995, the Company and four other unrelated entities were notified by the EPA that they have been designated as potentially responsible parties under the Comprehensive Environmental Response, Compensation and Liability Act with respect to a site in Brunswick,

Georgia. As of December 31, 2000, the Company has recognized approximately \$5 million in cumulative expenses associated with the Company's agreed upon share of removal and remedial investigation and feasibility study costs for this site. The final outcome of this matter cannot now be determined. However, based on the nature and extent of the Company's activities relating to the site, management believes that the Company's portion of any remaining remediation costs should not be material to the financial statements.

In compliance with the Georgia Hazardous Site Response Act of 1993, the State of Georgia was required to compile an inventory of all known or suspected sites where hazardous wastes, constituents, or substances have been disposed of or released in quantities deemed reportable by the State. In developing this list, the State identified several hundred properties throughout the State, including 34 sites which may require environmental remediation that were either previously or are currently owned by the Company. The majority of these sites are electrical power substations and power generation facilities. The Company has remediated ten electrical substations on the list at a cumulative cost of approximately \$3 million through December 31, 2000. The State has removed from the list three power generation facilities following the assessment which indicated no remediation was necessary. In addition, the Company has recognized approximately \$27.5 million in cumulative expenses through December 31, 2000 for the assessment of the remaining sites on the list and the anticipated clean-up cost for 14 sites that the Company plans to remediate. Any additional costs of remediating the remaining sites cannot presently be determined until such studies are completed for each site and the State determines whether remediation is required. If all listed sites were required to be remediated, the Company could incur expenses of up to approximately \$5 million in additional clean-up costs and construction expenditures of up to approximately \$37 million to develop new waste management facilities or install additional pollution control devices.

### **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.

In January 1997, the GPSC approved a performance award of approximately \$11.7 million for performance during the 1993-1995 period. This award was collected through the retail fuel cost recovery provision and recognized in income over the 36-month period ending in December 1999. In February 2000, the GPSC approved a performance award of approximately \$7.8 million for performance during the 1996-1998 period. This award is being collected through the retail fuel cost recovery provision and recognized in income over a 36-month period that began in January 2000, 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 and a new defendant, Southern Company Energy Solutions, Inc. The lawsuit is in the discovery stage. The final outcome of this case cannot now be determined.

### **4. COMMITMENTS**

#### **Construction Program**

The Company is constructing Plant Dahlberg, a ten unit, 800 megawatt combustion turbine peaking power plant. Units one through eight began operation in May 2000; units nine and ten are expected to begin operation in June 2001. The Company is also constructing a 571 megawatt combined cycle unit and a 610 megawatt combined cycle unit at Plant Goat Rock that will begin operation in 2002 and in 2003, respectively, and an addition of two 566 megawatt combined cycle units at Plant Wansley, to begin operation in 2002. During 2001, the Company plans to transfer the units at Plants Dahlberg, Goat Rock, and Wansley at net book value to Southern Power Company

(SPC), a new subsidiary formed by Southern Company. Significant construction of transmission and distribution facilities, and projects to upgrade and extend the useful life of generating plants and to remain in compliance with environmental requirements will continue. The Company currently estimates property additions to be approximately \$1.6 billion in 2001, \$1.3 billion in 2002, and \$0.8 billion in 2003. If the Company transfers wholesale generation assets to SPC in 2001 as contemplated, construction expenditures for the years 2001 through 2003 will total \$1.0 billion, \$0.9 billion, and \$0.7 billion, respectively.

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, 2000 were as follows:

<u>Year</u>	<u>Minimum Obligations</u> (in millions)
2001	\$1,006
2002	625
2003	586
2004	430
2005	342
2006 and beyond	873
<b>Total minimum obligations</b>	<b>\$3,862</b>

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

#### **Purchased Power Commitments**

The Company and an affiliate, Alabama Power Company, 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 Company 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:

	<b>2000</b>	1999	1998
	(in millions)		
Energy	<b>\$57</b>	\$51	\$45
Capacity	<b>30</b>	29	30
<b>Total</b>	<b>\$87</b>	\$80	\$75
Kilowatt-hours	<b>3,835</b>	3,338	3,146

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 \$58 million, \$57 million, and \$56 million in 2000, 1999, and 1998, respectively. The current projected Plant Vogtle capacity payments are:

<u>Year</u>	<u>Capacity Payments</u> (in millions)
2001	\$ 59
2002	58
2003	58
2004	55
2005	55
2006 and beyond	539
<b>Total capacity payments</b>	<b>\$824</b>

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, 2000 were as follows:

<u>Year</u>	<u>Other Obligations</u> (in millions)
2001	\$ 22
2002	39
2003	41
2004	40
2005	40
2006 and beyond	154
<b>Total other obligations</b>	<b>\$336</b>

### **Operating Leases**

The Company has entered into coal rail car rental agreements with various terms and expiration dates. These expenses totaled \$16 million for 2000, \$11 million for 1999, and \$13 million for 1998. At December 31, 2000, estimated minimum rental commitments for these noncancelable operating leases were as follows:

<u>Year</u>	<u>Minimum Obligations</u> (in millions)
2001	\$ 15
2002	15
2003	15
2004	16
2005	14
2006 and beyond	102
<b>Total minimum obligations</b>	<b>\$177</b>

### **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 private insurance, 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 be insured against increased costs of replacement power in an amount up to \$3.5 million per week -- starting 12 weeks after the outage -- for one year and up to \$2.8 million per week for the second and third 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 \$19 million.

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, 2000, the Company's percentage ownership and investment (exclusive of nuclear fuel) in jointly owned facilities in commercial operation were as follows:

Facility (Type)	Company		Accumulated Depreciation
	Ownership	Investment	
	(in millions)		
Plant Vogtle (nuclear)	45.7%	\$3,301*	\$1,724
Plant Hatch (nuclear)	50.1	873	650
Plant Wansley (coal)	53.5	300	150
Plant Scherer (coal)			
Units 1 and 2	8.4	112	53
Unit 3	75.0	545	207
Plant McIntosh			
Common Facilities (combustion-turbine)	75.0	19	2
Rocky Mountain (pumped storage)	25.4	169*	72
Intercession City (combustion-turbine)	33.3	11	1

\* Investment net of write-offs.

## 7. LONG-TERM POWER SALES AND LEASE AGREEMENTS

The Company and the other integrated Southeast utilities of Southern Company have long-term contractual agreements for the sale of capacity and energy to

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 (in millions)	Capacity (megawatts)
<b>2000</b>	<b>\$ 30</b>	<b>124</b>
1999	32	162
1998	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 2000 with a minimum of three years notice until the expiration of the contracts in 2010.

During 2000, the Company entered into certain operating leases for portions of its generating unit capacity. Minimum future capacity revenues from noncancelable operating leases as of December 31, 2000 were as follows:

Year	Minimum Obligations (in millions)
2001	\$ 41
2002	45
2003	45
2004	45
2005	5
2006 and beyond	-
<b>Total minimum obligations</b>	<b>\$181</b>

## 8. INCOME TAXES

At December 31, 2000, tax-related regulatory assets were \$566 million and tax-related regulatory liabilities were \$247 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:

	2000	1999	1998
Total provision for income taxes:		(in millions)	
Federal:			
Current	<b>\$ 342</b>	\$333	\$415
Deferred	<b>(34)</b>	(34)	(87)
Deferred investment tax credits	-	-	7
	<b>308</b>	299	335
State:			
Current	<b>48</b>	54	77
Deferred	<b>(5)</b>	(6)	(13)
Deferred investment tax credits	<b>10</b>	5	-
<b>Total</b>	<b>\$361</b>	\$352	\$399

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:

	2000	1999
	(in millions)	
Deferred tax liabilities:		
Accelerated depreciation	<b>\$1,755</b>	\$1,766
Property basis differences	<b>683</b>	729
Other	<b>243</b>	155
<b>Total</b>	<b>2,681</b>	2,650
Deferred tax assets:		
Other property basis differences	<b>189</b>	200
Federal effect of state deferred taxes	<b>91</b>	93
Other deferred costs	<b>208</b>	109
Other	<b>37</b>	48
<b>Total</b>	<b>525</b>	450
Net deferred tax liabilities	<b>2,156</b>	2,200
Portion included in current assets	<b>27</b>	3
Accumulated deferred income taxes in the Balance Sheets	<b>\$2,183</b>	\$2,203

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 2000 and 1999, and \$22 million in 1998. At December 31, 2000, 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:

	<b>2000</b>	1999	1998
Federal statutory rate	<b>35%</b>	35%	35%
State income tax, net of federal deduction	<b>4</b>	4	4
Non-deductible book depreciation	<b>2</b>	2	6
Other	<b>(2)</b>	(2)	(4)
<b>Effective income tax rate</b>	<b>39%</b>	39%	41%

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.

## 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. At December 31, 2000, \$891 million 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. If additional first mortgage bonds are issued, supplemental indentures in connection with those issues may contain more stringent restrictions than those currently in effect. 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	Rate	Notes	Maturity Date
		(millions)		(millions)	
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 \$378.8 million of its first mortgage bonds outstanding at December 31, 2000, which are pledged as security for its obligations under pollution control revenue contracts. No interest on these first mortgage bonds is payable unless and until a default occurs on the installment purchase or loan agreements.

### Senior Notes

In February 2000 and February 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, including its first mortgage bonds.

### Bank Credit Arrangements

At the beginning of 2001, the Company had unused credit arrangements with banks totaling \$1.8 billion, of which \$1.3 billion expires at various times during 2001, 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 20, 2001, 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 2001 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, 2000 was \$979 million.

In addition, the Company borrows under uncommitted lines of credit with banks and through a \$750 million commercial paper program that has the liquidity support of committed bank credit arrangements. Average compensating balances held under these committed facilities were not material in 2000.

### **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, 2000 and 1999, the Company had a capitalized lease obligation for its corporate headquarters building of \$87 million with an interest rate of 8.1 percent. The lease agreement provides for payments that are minimal in early years and escalate through the first 21 years of the lease. 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 is being deferred as a cost to be recovered in the future as ordered by the GPSC. At December 31, 2000 and 1999, the interest and lease amortization deferred on the Balance Sheets are \$55 million and \$54 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.

### **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:

	<u>2000</u>	<u>1999</u>
	(in millions)	
Bond improvement fund requirements	\$ -	\$ 5
Capital lease – current portion	2	1
First mortgage bond maturities and redemptions	-	100
Pollution control bond maturities and redemptions	-	50
<b>Total long-term debt</b>	<b>\$2</b>	<b>\$156</b>

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.

### **Redemption of Securities**

The Company plans to continue, to the extent possible, a program of redeeming or replacing debt and preferred securities in cases where opportunities exist to reduce financing costs. Issues may be repurchased in the open market or called at premiums as specified under terms of the issue. They may also be redeemed at face value to meet improvement fund requirements, to meet replacement provisions of the mortgage, or through use of proceeds from the sale of property pledged under the mortgage.

**10. QUARTERLY FINANCIAL DATA  
 (UNAUDITED)**

Summarized quarterly financial information for 2000 and 1999 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred Stock
	(in millions)		
<b>March 2000</b>	<b>\$ 992</b>	<b>\$223</b>	<b>\$ 94</b>
<b>June 2000</b>	<b>1,221</b>	<b>311</b>	<b>148</b>
<b>September 2000</b>	<b>1,545</b>	<b>537</b>	<b>283</b>
<b>December 2000</b>	<b>1,113</b>	<b>162</b>	<b>34</b>
March 1999	\$ 931	\$224	\$ 92
June 1999	1,092	299	138
September 1999	1,466	557	296
December 1999	968	115	15

Under the GPSC retail rate order, the Company recorded \$135 million and \$85 million of accelerated amortization in 2000 and 1999, respectively, which were recorded monthly as an operating expense. The fourth quarter December 1999 operating income has been restated to reflect the accelerated amortization as an operating expense rather than as amortization of premium on reacquired debt. See Note 3 to the financial statements under "Retail Rate Order" for additional information.

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

**SELECTED FINANCIAL AND OPERATING DATA 1996-2000**
**Georgia Power Company 2000 Annual Report**

	2000	1999	1998	1997	1996
<b>Operating Revenues</b> (in thousands)	<b>\$4,870,618</b>	\$4,456,675	\$4,738,253	\$4,385,717	\$4,416,779
<b>Net Income after Dividends</b>					
<b>on Preferred Stock</b> (in thousands)	<b>\$559,420</b>	\$541,383	\$570,228	\$593,996	\$580,327
<b>Cash Dividends</b>					
<b>on Common Stock</b> (in thousands)	<b>\$549,600</b>	\$543,000	\$536,600	\$520,000	\$475,500
<b>Return on Average Common Equity</b> (percent)	<b>13.66</b>	14.02	14.61	14.53	13.73
<b>Total Assets</b> (in thousands)	<b>\$13,133,609</b>	\$12,361,860	\$12,033,618	\$12,573,728	\$13,006,635
<b>Gross Property Additions</b> (in thousands)	<b>\$1,078,163</b>	\$790,464	\$499,053	\$475,921	\$428,220
<b>Capitalization</b> (in thousands):					
Common stockholder's equity	<b>\$4,249,544</b>	\$3,938,210	\$3,784,172	\$4,019,728	\$4,154,281
Preferred stock	<b>14,569</b>	14,952	15,527	157,247	464,611
Company obligated mandatorily redeemable preferred securities	<b>789,250</b>	789,250	689,250	689,250	325,000
Long-term debt	<b>3,041,939</b>	2,688,358	2,744,362	2,982,835	3,200,419
<b>Total</b> (excluding amounts due within one year)	<b>\$8,095,302</b>	\$7,430,770	\$7,233,311	\$7,849,060	\$8,144,311
<b>Capitalization Ratios</b> (percent):					
Common stockholder's equity	<b>52.5</b>	53.0	52.3	51.2	51.0
Preferred stock	<b>0.2</b>	0.2	0.2	2.0	5.7
Company obligated mandatorily redeemable preferred securities	<b>9.7</b>	10.6	9.5	8.8	4.0
Long-term debt	<b>37.6</b>	36.2	38.0	38.0	39.3
<b>Total</b> (excluding amounts due within one year)	<b>100.0</b>	100.0	100.0	100.0	100.0
<b>Security Ratings:</b>					
First Mortgage Bonds -					
Moody's	<b>A1</b>	A1	A1	A1	A1
Standard and Poor's	<b>A</b>	A+	A+	A+	A+
Fitch	<b>AA-</b>	AA-	AA-	AA-	AA-
Preferred Stock -					
Moody's	<b>a2</b>	a2	a2	a2	a2
Standard and Poor's	<b>BBB+</b>	A-	A	A	A
Fitch	<b>A</b>	A+	A+	A+	A+
Unsecured Long-Term Debt -					
Moody's	<b>A2</b>	A2	A2	A2	A2
Standard and Poor's	<b>A</b>	A	A	A	A
Fitch	<b>A+</b>	A+	A+	A+	A+
<b>Customers</b> (year-end):					
Residential	<b>1,669,566</b>	1,632,450	1,596,488	1,561,675	1,531,453
Commercial	<b>237,977</b>	229,524	221,180	211,672	205,087
Industrial	<b>8,533</b>	8,958	9,485	9,988	10,424
Other	<b>3,159</b>	3,060	3,034	2,748	2,645
<b>Total</b>	<b>1,919,235</b>	1,873,992	1,830,187	1,786,083	1,749,609
<b>Employees</b> (year-end):	<b>8,855</b>	8,961	8,371	8,354	10,346

**SELECTED FINANCIAL AND OPERATING DATA 1996-2000 (continued)**
**Georgia Power Company 2000 Annual Report**

	2000	1999	1998	1997	1996
<b>Operating Revenues (in thousands):</b>					
Residential	\$ 1,535,684	\$1,410,099	\$ 1,486,699	\$ 1,326,787	\$ 1,371,033
Commercial	1,620,466	1,527,880	1,591,363	1,493,353	1,486,586
Industrial	1,154,789	1,143,001	1,170,881	1,110,311	1,118,633
Other	6,399	(30,892)	49,274	47,848	47,060
Total retail	4,317,338	4,050,088	4,298,217	3,978,299	4,023,312
Sales for resale - non-affiliates	297,643	210,104	259,234	282,365	281,580
Sales for resale - affiliates	96,150	76,426	81,606	38,708	35,886
Total revenues from sales of electricity	4,711,131	4,336,618	4,639,057	4,299,372	4,340,778
Other revenues	159,487	120,057	99,196	86,345	76,001
<b>Total</b>	<b>\$4,870,618</b>	<b>\$4,456,675</b>	<b>\$4,738,253</b>	<b>\$4,385,717</b>	<b>\$4,416,779</b>
<b>Kilowatt-Hour Sales (in thousands):</b>					
Residential	20,693,481	19,404,709	19,481,486	17,295,022	17,826,451
Commercial	25,628,402	23,715,485	22,861,391	21,134,346	20,823,073
Industrial	27,543,265	27,300,355	27,283,147	26,701,685	26,191,831
Other	568,906	551,451	543,462	538,163	536,057
Total retail	74,434,054	70,972,000	70,169,486	65,669,216	65,377,412
Sales for resale - non-affiliates	6,463,723	5,060,931	6,438,891	6,795,300	7,868,342
Sales for resale - affiliates	2,435,106	1,795,243	2,038,400	1,706,699	1,180,207
<b>Total</b>	<b>83,332,883</b>	<b>77,828,174</b>	<b>78,646,777</b>	<b>74,171,215</b>	<b>74,425,961</b>
<b>Average Revenue Per Kilowatt-Hour (cents):</b>					
Residential	7.42	7.27	7.63	7.67	7.69
Commercial	6.32	6.44	6.96	7.07	7.14
Industrial	4.19	4.19	4.29	4.16	4.27
Total retail	5.80	5.71	6.13	6.06	6.15
Sales for resale	4.43	4.18	4.02	3.78	3.51
Total sales	5.65	5.57	5.90	5.80	5.83
<b>Residential Average Annual</b>					
<b>Kilowatt-Hour Use Per Customer</b>	<b>12,520</b>	12,006	12,314	11,171	11,763
<b>Residential Average Annual</b>					
<b>Revenue Per Customer</b>	<b>\$929.11</b>	\$872.47	\$939.73	\$857.01	\$904.70
<b>Plant Nameplate Capacity</b>					
<b>Ratings (year-end) (megawatts)</b>	<b>15,114</b>	14,474	14,437	14,437	14,367
<b>Maximum Peak-Hour Demand (megawatts):</b>					
Winter	12,014	11,568	11,959	10,407	10,410
Summer	14,930	14,575	13,923	13,153	12,914
<b>Annual Load Factor (percent)</b>	<b>61.6</b>	58.9	58.7	57.4	62.2
<b>Plant Availability (percent):</b>					
Fossil-steam	86.1	84.3	86.0	85.8	85.2
Nuclear	91.5	89.3	91.6	88.8	89.3
<b>Source of Energy Supply (percent):</b>					
Coal	62.3	63.0	62.3	64.3	60.4
Nuclear	17.4	18.0	18.3	18.8	18.2
Hydro	0.7	0.9	2.2	2.2	2.2
Oil and gas	1.8	1.6	2.2	0.6	0.5
Purchased power -					
From non-affiliates	8.1	6.6	6.5	2.7	5.6
From affiliates	9.7	9.9	8.5	11.4	13.1
<b>Total</b>	<b>100.0</b>	100.0	100.0	100.0	100.0

## DIRECTORS AND OFFICERS

Georgia Power Company 2000 Annual Report

### Directors

**Daniel P. Amos**

President and Chief Executive Officer  
American Family Life Assurance Company, Inc.

**Juanita P. Baranco**

Executive Vice President  
Baranco Automotive Group

**William A. Fickling, Jr.**

Chairman of the Board  
Beech Street Corporation

**H. Allen Franklin**

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

**William Jerry Vereen**

President, Treasurer and Chief Executive Officer  
Riverside Manufacturing Company

**Carl Ware**

Executive Vice President  
The Coca-Cola Company

**E. Jenner Wood, III** (effective 1/25/01)

Chairman, President and Chief Executive Officer  
SunTrust Bank, Atlanta and 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

**Gene R. Hodges**

Executive Vice President  
Customer Operations

**Warren Y. Jobe**

Executive Vice President

**C. D. McCrary**

Executive Vice President

**James K. Davis**

Senior Vice President  
Employee/Corporate Relations

**Robert H. Haubein**

Senior Vice President  
Fossil and Hydro Power

**Leonard J. Haynes**

Senior Vice President  
Marketing

**Fred D. Williams**

Senior Vice President  
Resource Policy and Planning

**David R. Altman**

Vice President  
Public Relations/  
Corporate Communications

## **DIRECTORS AND OFFICERS** (continued)

Georgia Power Company 2000 Annual Report

**Judy M. Anderson**  
Vice President and  
Corporate Secretary

**Ronnie L. Bates**  
Vice President  
Transmission

**Robert S. Beason**  
Vice President  
Information Resources

**Rebecca A. Blalock**  
Vice President  
Community and Economic Development

**Robert L. Boyer**  
Vice President  
Power Generation

**M. A. Brown**  
Vice President  
Distribution

**A. Bryan Fletcher**  
Vice President  
Governmental and  
Regulatory Affairs

**J. Kevin Fletcher**  
Vice President  
Retail Sales and Service

**O. Ben Harris**  
Vice President  
Land

**Richard L. Holmes**  
Vice President  
Metro and West Regions

**E. Lamont Houston**  
Vice President  
Metro and South Regions

**J. B. Manley**  
Vice President  
Metro and Northern Regions

**Frank J. McCloskey**  
Vice President  
Diversity

**Phil Saunders**  
Vice President  
Information Resources  
(effective 3/1/01)

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

**J. L. Wallace**  
Vice President  
Customer Service

**C. C. Womack**  
Vice President  
Human Resources

**Wayne Boston**  
Assistant Secretary and  
Assistant Treasurer

**W. R. Hinson**  
Assistant Comptroller

**Allen L. Leverett**  
Assistant Treasurer

**Janice G. Wolfe**  
Assistant Corporate Secretary

## **CORPORATE INFORMATION**

Georgia Power Company 2000 Annual Report

### **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 1.9 million customers within its service area of approximately 57,000 square miles. In 2000, retail energy sales accounted for 89 percent of the Company's total sales of 83.3 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 33<sup>rd</sup> 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.**

### **Georgia Power Company**

241 Ralph McGill Boulevard, N.E.  
Atlanta, GA 30308-3374  
(404) 506-6526  
[www.georgiapower.com](http://www.georgiapower.com)

### **Auditors**

Arthur Andersen LLP  
133 Peachtree Street, N.E.  
Atlanta, GA 30303

### **Legal Counsel**

Troutman Sanders LLP  
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Suite 5200  
Atlanta, GA 30308