ARS

P.E. 12-31-03

2003 Annual Report

ALABAMA POWER CO

A SOUTHERN COMPANY

CONTENTS

Alabama Power Company 2003 Annual Report

SUMMARY

	2003	2002	Percent Change
Financial Highlights *(in millions)*:			
Operating revenues	**$3,960**	$3,710	6.7
Operating expenses	**$2,945**	$2,688	9.6
Net income after dividends on preferred stock	**$473**	$461	2.5
Operating Data:			
Kilowatt-hour sales *(in millions)*:			
Retail	**52,208**	52,073	0.3
Sales for resale - non-affiliates	**17,086**	15,554	9.9
Sales for resale - affiliates	**9,422**	8,844	6.5
Total	**78,716**	76,471	2.9
Customers served at year-end *(in thousands)*	**1,370**	1,357	1.0
Peak-hour demand *(in megawatts)*	**10,462**	10,910	(4.1)
Capitalization Ratios *(percent)*:			
Common stock equity	**46.4**	49.7	
Preferred stock	**4.9**	3.6	
Mandatorily redeemable preferred securities	**4.0**	4.4	
Long-term debt	**44.7**	42.3	
(Excluding long-term debt due within one year)			
Return on Average Common Equity *(percent)*	**13.75**	13.80	

The year 2003 was a year of great uncertainty as our country went to war and the recovery of our national economy remained in doubt. But at least one thing remained constant – Alabama Power Company continued to produce results for our shareholders, customers and communities.

Our customers know they can count on Alabama Power to provide reliable service and low prices. Our shareholders know they can count on us to make every effort to meet our financial goals. Further, our communities know they can count on us to be environmentally responsible and to help make our state a better place to live for everyone.

Once again, Alabama Power met or surpassed all of its financial goals, enabling us to keep our promises to our shareholders.

Our generating plants far surpassed their goals during the peak usage months, assuring that our customers would have electricity when they needed it, at prices 15 percent below the national average. Likewise, thanks to our excellent transmission and distribution system, electric service was available to our customers 99.97 percent of the time.

We continued to improve our customer value ratings and now rank number one among residential customers and number two overall.

At the same time, we continued our efforts to reduce our impact on the environment we all treasure. In 2003, Alabama Power continued to install state-of-the-art emissions reduction equipment and technology at our generating plants.

We had a successful year and we believe the key to that success will always be the same: Make every decision with the best interest of your customer, shareholder and employee in mind. Take every action based upon the highest standards of ethics and integrity. Our business may change but these are beliefs you can count on always.

Solid values, a strong commitment to our customers and sound business strategies allowed us to successfully face the challenges of 2003, and they will allow us to move into the future in a position of strength.

Sincerely,

Charles D. McCrary

Charles D. McCrary
President and Chief Executive Officer
March 19, 2004

MANAGEMENT'S REPORT

The management of Alabama Power Company has prepared -- and is responsible for -- the financial statements and related information included in this report. 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, however, based on a recognition that the cost of the system should not exceed its benefits. The Company believes its system of internal accounting controls maintains an appropriate cost/benefit relationship.

The Company's internal accounting controls are 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.

Southern Company's audit committee of its board of directors, composed of four independent directors, provides a broad overview of management's financial reporting and control functions. Additionally, the controls and compliance committee of Alabama Power's board of directors, composed of three outside directors, meets periodically with management, the internal auditors, and the independent public accountants to discuss auditing, internal controls, and compliance matters. The internal auditors and independent public accountants have access to the members of these committees at any time.

Management believes that its policies and procedures provide reasonable assurance that the Company's operations are conducted according to 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 Alabama Power Company in conformity with accounting principles generally accepted in the United States.

Charles D. McCrary
President
and Chief Executive Officer

William B. Hutchins, III
Executive Vice President,
Chief Financial Officer, and Treasurer

March 1, 2004

INDEPENDENT AUDITORS' REPORT

Alabama Power Company:

We have audited the accompanying balance sheets and statements of capitalization of Alabama Power Company (a wholly owned subsidiary of Southern Company) as of December 31, 2003 and 2002, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for the years then ended. These financial statements are the responsibility of Alabama Power Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. The financial statements of Alabama Power Company for the year ended December 31, 2001 were audited by other auditors who have ceased operations. Those auditors expressed an unqualified opinion on those financial statements and included an explanatory paragraph that described a change in the method of accounting for derivative instruments and hedging activities in their report dated February 13, 2002.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. 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 21 to 43) present fairly, in all material respects, the financial position of Alabama Power Company at December 31, 2003 and 2002, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the financial statements, in 2003 Alabama Power Company changed its method of accounting for asset retirement obligations.

Deloitte & Touche LLP

Birmingham, Alabama
March 1, 2004

THE FOLLOWING REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS IS A COPY OF THE REPORT PREVIOUSLY ISSUED IN CONNECTION WITH THE COMPANY'S 2001 ANNUAL REPORT AND HAS NOT BEEN REISSUED BY ARTHUR ANDERSEN LLP.

To Alabama Power Company:

We have audited the accompanying balance sheets and statements of capitalization of Alabama Power Company (an Alabama corporation and a wholly owned subsidiary of Southern Company) as of December 31, 2001 and 2000, 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, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements (pages 15-33) referred to above present fairly, in all material respects, the financial position of Alabama Power Company as of December 31, 2001 and 2000, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

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

Arthur Andersen LLP

Birmingham, Alabama
February 13, 2002

OVERVIEW OF EARNINGS AND BUSINESS ACTIVITIES

Earnings

Alabama Power Company's 2003 net income after dividends on preferred stock was $473 million, representing a $12 million (2.5 percent) increase from the prior year. This improvement is due primarily to higher sales for resale, increases in other revenues, and lower interest expense, partially offset by higher non-fuel operating expenses.

In 2002, earnings were $461 million, representing a 19.3 percent increase from the prior year. This improvement was primarily attributable to increased territorial energy sales and higher retail rates when compared to the prior year. More favorable weather conditions in 2002 as compared to the unusually mild weather experienced in 2001 contributed to the increases in territorial sales. The increases in revenues were partially offset by increased non-fuel operating expenses. Earnings in 2001 were $387 million, representing a 7.9 percent decrease from the prior year. This decline was primarily attributable to a decrease in territorial energy sales as a result of an economic downturn and milder temperatures.

The return on average common equity for 2003 was 13.75 percent compared to 13.80 percent in 2002 and 11.89 percent in 2001.

Business Activities

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

Several factors affect the opportunities, challenges, and risk of the Company's primary business of selling electricity. These factors include the ability to maintain a stable regulatory environment, to achieve energy sales growth while containing costs, and to recover costs related to growing demand and increasingly stricter environmental standards. Future earnings in the near term will depend, in part, upon growth in energy sales, which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price elasticity of demand, and the rate of economic growth in the service area.

RESULTS OF OPERATIONS

A condensed income statement is as follows:

	Amount	Increase (Decrease) From Prior Year		
	2003	**2003**	2002	2001
	(in millions)			
Operating revenues	**$3,960**	**$250**	$124	$(81)
Fuel	**1,068**	**98**	(31)	38
Purchased power	**315**	**66**	(44)	(56)
Other operation and maintenance	**921**	**67**	71	(56)
Depreciation and amortization	**413**	**15**	15	19
Taxes other than income taxes	**228**	**11**	2	5
Total operating expenses	**2,945**	**257**	13	(50)
Operating income	**1,015**	**(7)**	111	(31)
Other income (expense), net	**(252)**	**17**	7	(15)
Less -- Income taxes	**290**	**(2)**	44	(13)
Net Income	**$ 473**	**$ 12**	$ 74	$(33)

Revenues

Operating revenues for 2003 were nearly $4.0 billion, reflecting a $250 million increase from 2002. The following table summarizes the principal factors that have affected operating revenues for the past three years:

	Amount		
	2003	2002	2001
	(in millions)		
Retail -- prior year	**$2,951**	$2,748	$2,953
Change in -			
Base rates	**51**	76	23
Sales growth	**68**	70	(36)
Weather	**(61)**	60	(62)
Fuel cost recovery and other	**42**	(3)	(130)
Retail -- current year	**3,051**	2,951	2,748
Sales for resale --			
Non-affiliates	**488**	474	486
Affiliates	**277**	188	245
Total sales for resale	**765**	662	731
Other operating revenues	**144**	97	107
Total operating revenues	**$3,960**	$3,710	$3,586
Percent change	**6.7%**	3.5%	(2.2)%

Retail revenues in 2003 were $3.1 billion. Revenues increased $100 million (3.4 percent) from the prior year, increased $203 million (7.4 percent) in 2002, and decreased $205 million (6.9 percent) in 2001. All sectors of retail revenues increased for the Company in 2003 primarily due to increased fuel revenue and a 2.6 percent increase in retail base rates which went into effect in July 2003. See Note 3 to the financial statements under "Retail Rate Adjustment Procedures" for additional information.

The primary contributors to the increase in revenues in 2002, shown in the table above, were the positive effect of favorable weather conditions on energy sales and increases in retail base rates (0.6 percent increase in July 2001 and 2 percent increases in both October 2001 and April 2002). The Company mitigated the effect of these increases to customers with a decrease to the energy cost recovery factor in April 2002.

The revenue decrease in 2001 was primarily due to the negative impact of milder temperatures on energy sales and an economic downturn in the Company's service territory.

Fuel rates billed to customers are designed to fully recover fluctuating fuel costs over a period of time. At December 31, 2003, the Company had no unrecovered fuel costs. Fuel revenues have no effect on net income because they represent the recording of revenues to offset fuel expenses.

Sales for resale to non-affiliates are predominantly unit power sales under long-term contracts to Florida utilities. Revenues from power sales contracts have both capacity and energy components. Capacity revenues reflect the recovery of fixed costs and a return on investment under the contracts. Energy is generally sold at variable cost. These capacity and energy components of the unit power contracts were as follows:

	2003	2002	2001
	(in thousands)		
Unit power -			
Capacity	**$130,022**	$119,193	$124,720
Energy	**145,342**	134,051	134,006
Total	**$275,364**	$253,244	$258,726

There are no significant scheduled declines in unit power sales capacity until the termination of the unit power sales contracts in 2010.

Short-term opportunity energy sales are also included in sales for resale to non-affiliates. These opportunity sales are made at market rates that generally include the recovery of fixed costs and a return, in addition to the variable energy cost. Revenues associated with other power sales to non-affiliates were as follows:

	2003	2002	2001
	(in thousands)		
Other power sales -			
Capacity and other	**$33,858**	$14,613	$ 13,324
Variable cost of energy	**44,627**	61,925	91,608
Total	**$78,485**	$76,538	$104,932

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. Sales for resale revenues increased $26.6 million in 2003 due to increased capacity payments received in accordance with the affiliated company interchange agreements as a result of increased capacity. Excluding the capacity revenues, these transactions do not have a significant impact on earnings since the energy is generally sold at marginal cost and energy purchases are generally offset by energy revenues through the Company's energy cost recovery clause.

Other operating revenues in 2003 increased $47 million (48.6 percent) from 2002 due to an increase of $19.4 million in revenues from gas-fueled co-generation steam facilities -- primarily as a result of higher gas prices -- and a $14.8 million increase in revenues from Alabama Public Service Commission (Alabama PSC) approved fees charged to customers for connection, reconnection, and collection when compared to the same period in 2002. Since co-generation steam revenues are generally offset by fuel expenses, these revenues did not have a significant impact on earnings.

The $11 million (9.9 percent) decrease in other operating revenues in 2002 resulted primarily from a $7.0 million decrease in revenues from gas-fueled co-generation steam facilities due to lower gas prices and lower demand. The $21 million (23.9 percent) increase in 2001 was primarily attributed to a $6.4 million increase in steam sales in conjunction with the operation of the Company's co-generation facilities, a $5.3 million increase in fuel sales, and a $5.1 million increase in rent from electric property.

Energy Sales

Changes in revenues are influenced heavily by the volume of energy sold each year. Kilowatt-hour (KWH) sales for 2003 and the percent change by year were as follows:

	KWH	Percent Change		
	2003	**2003**	2002	2001
	(millions)			
Residential	**16,960**	**(2.5)%**	9.6%	(5.3)%
Commercial	**13,452**	**0.7**	4.4	(1.5)
Industrial	**21,593**	**2.3**	3.1	(7.4)
Other	**203**	**(1.1)**	3.7	(3.9)
Total retail	**52,208**	**0.3**	5.5	(5.2)
Sales for resale -				
Non-affiliates	**17,086**	**9.9**	1.8	2.9
Affiliates	**9,422**	**6.5**	-	64.7
Total	**78,716**	**2.9**	4.1	1.6

Residential energy sales for 2003 experienced a 2.5 percent decrease over the prior year and total retail energy sales grew by 0.3 percent primarily as a result of milder-than-normal summer temperatures compared to the previous year. Although retail sales to industrial customers increased 2.3 percent in 2003 and 3.1 percent in 2002, overall sales to industrial customers remained depressed due to the continuing effect of sluggish economic conditions.

Residential energy sales for 2002 experienced a 9.6 percent increase over the prior year and total retail energy sales grew by 5.5 percent primarily as a result of warmer summer temperatures and colder winter weather conditions compared to the previous year.

The decrease in 2001 retail energy sales was primarily due to milder temperatures and an economic downturn in the Company's service area. This was offset by an increase in sales for resale to affiliates. Increased operation of the Company's combined cycle facilities due to lower natural gas prices and an increase in the Company's combined cycle capacity contributed to the increase in sales for resale.

Assuming normal weather, sales to retail customers are projected to grow approximately 1.7 percent annually on average during 2004 through 2008.

Expenses

The total operating expenses in 2003 were approximately \$3.0 billion, an increase of \$257 million (9.6 percent) over the previous year. This increase is mainly due to a \$98 million increase in fuel expense primarily related to an increase in the average cost of natural gas and coal. In addition, purchased power expenses increased a total of \$66 million, maintenance expense increased \$30 million primarily related to transmission and distribution overhead lines, and depreciation and amortization expense increased \$15 million.

In 2002, total operating expenses of \$2.7 billion increased by \$13 million (0.5 percent) over the previous year. This slight increase was mainly due to a \$35 million increase in administrative and general expenses primarily related to employee salaries, insurance expense, and accrued expenses for liability insurance, litigation and workers compensation, a \$19 million increase in production expenses related to boiler plant maintenance, and a \$15 million increase in depreciation and amortization expenses due to an increase in depreciable property. These increases were offset by a \$43 million decrease in purchased power expenses and a \$14 million decrease in fuel expenses related to lower coal prices.

In 2001, total operating expenses of \$2.7 billion were down \$50 million (1.8 percent) compared with 2000. This decline was mainly due to an \$18 million net decrease in fuel and purchased power costs related to lower fuel prices, increased hydro generation and added capacity. The Company also had a \$56 million decrease in non-production operation and maintenance expense related to settlements received in connection with the Company's insurance program, lower costs related to services provided by Southern Company Services (SCS) and Southern Nuclear Operating Company, and a reduction to the natural disaster reserve accrual. These decreases in expense were partially offset by a \$19 million increase in depreciation and amortization due to an increase in depreciable property.

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

	2003	2002	2001
Total generation (billions of KWHs)	**72**	71	68
Sources of generation (percent) --			
Coal	**64**	62	64
Nuclear	**19**	19	18
Hydro	**8**	6	6
Gas	**9**	13	12
Average cost of fuel per net kilowatt-hour generated (cents)	**1.67**	1.47	1.56
Average cost of purchased power per net kilowatt-hour (cents)	**3.56**	2.91	3.28

In 2003, total fuel and purchased power expenses of $1.4 billion increased $164 million (13.4 percent) over 2002 due to a 58.3 percent increase in average gas prices and a 2.2 percent increase in average coal prices. Fuel and purchased power expenses in 2002 of $1.2 billion decreased $75 million (5.8 percent) due primarily to lower average fuel cost, while total energy sales increased 3.0 billion kilowatt hours (4.1 percent) compared with the amounts recorded in 2001. Fuel and purchased power expenses in 2001 decreased $18 million (1.4 percent) compared to 2000 because of reduced generation due to milder temperatures in 2001. Fuel expenses, including purchased power, are offset by fuel revenues through the Company's energy cost recovery clause and have no effect on net income.

Purchased power consists of purchases from affiliates in the Southern electric system and non-affiliated companies. Purchased power transactions among the Company and its affiliates will vary from period to period depending on demand, the availability, and the variable production cost of generating resources at each company. In 2003, purchased power from non-affiliates increased $20 million (22 percent) due to a 19.3 percent increase in price and a 9.5 percent increase in energy purchased when compared to 2002. During 2002, purchased power transactions from non-affiliates decreased $54 million (37 percent) due to the addition in May 2001 of a combined cycle unit which generated 6.1 billion kilowatt hours in 2002, an 18.4 percent increase over the previous year. Purchased power transactions from non-affiliates also declined in 2001 because of the addition of the combined cycle unit and an increase in hydro generation resulting in a $20 million (12 percent) decline from the year 2000.

Depreciation and amortization expense increased 3.6 percent in 2003, 3.9 percent in 2002, and 5.2 percent in 2001. These increases reflect additions to property, plant, and equipment.

Allowance for Equity Funds Used During Construction (AFUDC) increased $1.4 million (12.8 percent) in 2003 due to an increase in the applicable AFUDC rate. AFUDC increased $4 million (57.5 percent) in 2002 due to an increase in the amount of construction work in progress over the prior year. AFUDC decreased $16 million (68.9 percent) in 2001 due to completing construction of Plant Barry Unit 7 and placing it in service in May 2001.

Interest expense, net of amounts capitalized, of $214 million in 2003 decreased $11.4 million (5.1 percent) from 2002, which had decreased $21 million (8.4 percent) from 2001. Both years reflect a decrease in interest rates on long-term debt due to refinancing activities. Interest expense increased $11 million (4.7 percent) in 2001 compared to 2000.

Effects of Inflation

The Company is subject to rate regulation that is based on the recovery of historical costs. In addition, the income tax laws are also based on 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 plant with long economic lives. Conventional accounting for historical cost does not recognize this economic loss nor the partially offsetting gain that arises through financing facilities with fixed-money obligations, such as long-term debt and preferred securities. Any recognition of inflation by regulatory authorities is reflected in the rate of return allowed.

Future Earnings Potential

General

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors. Major factors include the ability of the Company to maintain a stable regulatory environment, to achieve energy sales growth while containing costs, and to recover costs related to growing demand and increasingly stricter environmental standards. Growth in energy sales is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price elasticity of demand, and the rate of economic growth in the Company's service area.

Industry Restructuring

The Company operates as a vertically integrated utility providing electricity to customers within its traditional service area located in the State of Alabama and to wholesale customers in the Southeast.

The electric utility industry in the United States is continuing to evolve as a result of regulatory and competitive factors. Among the early primary agents of change was the Energy Policy Act of 1992 (Energy Act). The Energy Act allowed independent power producers to access a utility's transmission network and sell electricity to other utilities.

Although the Energy Act does not provide for retail customer access, it was a major catalyst for restructuring and consolidations that took place within the utility industry. Numerous federal and state initiatives that promote wholesale and retail competition are in varying stages. Among other things, these initiatives allow retail customers in some states to choose their electricity provider. Some states have approved initiatives that result in a separation of the ownership and/or operation of generating facilities from the ownership and/or operation of transmission and distribution facilities. While various restructuring and competition initiatives have been discussed in Alabama, none have been enacted. In October 2000, the Alabama PSC completed a two-year study of electric industry restructuring, concluding that (i) restructuring of the electric utility industry in Alabama was not in the public interest and (ii) the Alabama PSC itself could not mandate retail competition or electric industry restructuring without enabling state legislation. Electric utility restructuring could require numerous issues to be resolved, including significant ones relating to recovery of any stranded investments, full cost recovery of energy produced, and other issues related to the energy crisis that occurred in California as well as the August 2003 power outage in the Northeast.

Since 2001, merchant energy companies and traditional electric utilities with significant energy marketing and trading activities have come under severe financial pressures. Many of these companies have completely exited or drastically reduced all energy marketing and trading activities and sold foreign and domestic electric infrastructure assets. The Company has not experienced any material adverse financial impact regarding its limited energy trading operations through SCS.

Continuing to be a low-cost producer could provide opportunities to increase the size and profitability in markets that evolve with changing regulation and competition. Conversely, future regulatory changes could adversely affect the Company's growth, and if the Company does not remain a low-cost producer and provide quality service, then energy sales growth could be limited, and this could significantly erode earnings.

Environmental Matters

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action against the Company alleging that the Company had violated the New Source Review (NSR) provisions of the Clean Air Act with respect to coal-fired generating facilities at the Company's Plants Miller, Barry, and Gorgas. 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 action against the Company has been stayed since the spring of 2001 during the appeal of a very similar NSR action against the Tennessee Valley Authority before the U.S. Court of Appeals for the Eleventh Circuit. The Eleventh Circuit appeal was decided on September 16, 2003, and, on February 13, 2004, the EPA petitioned the U.S. Supreme Court to review the Eleventh Circuit's decision. The EPA also filed a motion to lift the stay in the action against the Company. See Note 3 to the financial statements under "New Source Review Actions" for additional information.

In December 2002 and October 2003, the EPA issued final revisions to its NSR regulations under the Clean Air Act. The December 2002 revisions included changes to the regulatory exclusions and the methods of calculating emissions increases. The October 2003 regulations clarified the scope of the existing Routine Maintenance, Repair, and Replacement exclusion. A coalition of states and environmental organizations filed petitions for review of these revisions with the U.S. Court of Appeals for the District of Columbia Circuit. On December 24, 2003, the Court of Appeals granted a stay of the October 2003 revisions pending its review of the rules and ordered that its review be conducted on an expedited basis. In January 2004, the Bush Administration announced that it would continue to enforce the existing rules until the courts resolve legal challenges to the EPA's revised NSR regulations. In any event, the final regulations must be adopted by the State of Alabama in order to apply to the Company's facilities. The effect of these final regulations and the related legal challenges cannot be determined at this time.

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 in this matter could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

Environmental Statutes and Regulations

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Compliance with these environmental requirements will involve significant costs -- both capital and operating -- a major portion of which is expected to be recovered through existing ratemaking provisions. Environmental costs that are known and estimable at this time are included in capital expenditures discussed under "Capital Requirements and Contractual Obligations." There is no assurance, however, that all such costs will, in fact, be recovered.

Compliance with the federal Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. The Title IV acid rain provisions of the Clean Air Act, for example, required significant reductions in sulfur dioxide and nitrogen oxide emissions. Title IV compliance, effective in 2000, and associated construction expenditures totaled approximately $88 million. Some of these expenditures also assisted the Company in complying with nitrogen oxide emission reduction requirements under Title I of the Clean Air Act, which were designed to address one-hour ozone nonattainment problems in Birmingham, Alabama. In December 2000, the Alabama Department of Environmental Management (ADEM) adopted revisions to the State Implementation Plan (SIP) for meeting the one-hour ozone standard. These revisions required additional nitrogen oxide emission reductions from May through September of each year at plants in and/or near those nonattainment areas. Two plants in the Birmingham area are currently subject to those requirements, the most recent of which went into effect in 2003. Construction expenditures for compliance with the nitrogen oxide emission reduction requirements are estimated to be approximately $249 million.

To help ozone nonattainment areas attain the one-hour ozone standard, the EPA issued regional nitrogen oxide reduction rules in 1998. Those rules required 21 states, including Alabama, to reduce and cap nitrogen oxide emissions from power plants and other large industrial sources. Affected sources, including five of the Company's coal-fired plants, must comply with the reduction requirements by May 31, 2004. Additional construction expenditures for compliance with these rules are currently estimated at approximately $361 million, of which $317 million remains to be spent.

In July 1997, the EPA revised the national ambient air quality standards for ozone and particulate matter. These revisions made the standards significantly more stringent. In the subsequent litigation of these standards, the U.S. Supreme Court found the EPA's implementation program for the new eight-hour ozone standard unlawful and remanded it to the EPA for further rulemaking. During 2003, the EPA proposed implementation rules designed to address the court's concerns. The EPA plans to designate areas as attainment or nonattainment with the new eight-hour ozone standard in April 2004 and with the new fine particulate matter standard by the end of 2004. These designations will be based on air quality data for 2001 through 2003. Several areas within the Company's service area are likely to be designated nonattainment under these standards. SIPs, including new emission control regulations necessary to bring those areas into attainment, could be required as early as 2007. These SIPs could require reductions in sulfur dioxide emissions and could require further reductions in nitrogen oxide emissions from power plants. If so, reductions could be required sometime after 2007. The impact of any new standards will depend on the development and implementation of applicable regulations and cannot be determined at this time.

In January 2004, the EPA issued a proposed Interstate Air Quality Rule to address interstate transport of ozone and fine particles. This proposed rule would require additional year-round sulfur dioxide and nitrogen oxide emission reductions from power plants in the eastern United States in two phases – in 2010 and 2015. The EPA currently plans to finalize this rule by 2005. If finalized, the rule could modify or supplant other SIP requirements for attainment of the fine particulate matter standard and the eight-hour ozone standard. The impact of this rule on the Company will depend upon the specific requirements of the final rule and cannot be determined at this time.

Further reductions in sulfur dioxide and nitrogen oxides could also be required under the EPA's Regional Haze rules. The Regional Haze rules require states to establish Best Available Retrofit Technology (BART) standards for certain sources that contribute to regional haze. The Company has a number of plants that could be subject to these rules. The EPA's Regional Haze program calls for states to submit SIPs in 2007. The SIPs must contain emission reduction strategies for implementing BART and achieving progress toward the Clean Air Act's visibility improvement goal. In 2002, however, the U.S. Court of Appeals for the District of Columbia Circuit vacated and remanded the BART provisions of the federal Regional Haze rules to the EPA for further rulemaking. The EPA has entered into an agreement that requires proposed revised rules in April 2004 and final rules in 2005. Because new BART rules have not been developed and state visibility assessments for progress are only beginning, it is not possible to determine the effect of these rules on the Company at this time.

The EPA's Compliance Assurance Monitoring (CAM) regulations under Title V of the Clean Air Act require that monitoring be performed to ensure compliance with emissions limitations on an ongoing basis. In 2004 and 2005, a number of the Company's plants will likely become subject to CAM requirements for at least one pollutant, in most cases particulate matter. The Company is in the process of developing CAM plans. Because the plans are still under development, the Company cannot determine the costs associated with implementation of the CAM regulations. Actual ongoing monitoring costs are expensed as incurred and are not material for any year presented.

In January 2004, the EPA issued proposed rules regulating mercury emissions from electric utility boilers. The proposal solicits comments on two possible approaches for the new regulations – a Maximum Achievable Control Technology approach and a cap-and-trade approach. Either approach would require significant reductions in mercury emissions from Company facilities. The regulations are scheduled to be finalized by the end of 2004, and compliance could be required as early as 2007. Because the regulations have not been finalized, the impact on the Company cannot be determined at this time.

Several major bills to amend the Clean Air Act to impose more stringent emissions limitations on power plants have been proposed by Congress. Three of these, the Bush Administration's Clear Skies Act, the Clean Power Act of 2003, and the Clean Air Planning Act of 2003, propose to further limit power plant emissions of sulfur dioxide, nitrogen oxides, and mercury. The latter two bills also propose to limit emissions of carbon dioxide. The cost impacts of such legislation would depend upon the specific requirements enacted and cannot be determined at this time.

Domestic efforts to limit greenhouse gas emissions, have been spurred by international discussions surrounding the Framework Convention on Climate Change and, specifically, the Kyoto Protocol, which proposes international constraints on the emissions of greenhouse gases. The Bush Administration does not support U.S. ratification of the Kyoto Protocol or other mandatory carbon dioxide reduction legislation and has instead announced a new voluntary climate initiative, known as Climate VISION, which seeks an 18 percent reduction by 2012 in the rate of greenhouse gas emissions relative to the dollar value of the U.S. economy. The Company is involved in a voluntary electric utility industry sector climate change initiative in partnership with the government. The electric utility sector has pledged to reduce its greenhouse gas intensity 3 percent to 5 percent over the next decade and is in the process of developing a memorandum of understanding with the Department of Energy (DOE) to cover this voluntary program.

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and will recognize in its financial statements costs to clean up known sites. Amounts for cleanup and ongoing monitoring costs were not material for any new year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. The Company has not incurred any significant cleanup costs to date.

Under the Clean Water Act, the EPA has been developing new rules aimed at reducing impingement and entrainment of fish and fish larvae at power plants' cooling water intake structures. On February 16, 2004, the EPA finalized these rules. These rules will require biological studies and, perhaps, retrofits to some intake structures at existing power plants. The impact of these new rules will depend on the results of studies and analyses performed as part of the rules' implementation.

In addition, under the Clean Water Act, the EPA and the ADEM are developing total maximum daily loads (TMDLs) for certain impaired waters. Establishment of maximum loads by the EPA or the ADEM may result in lowering permit limits for various pollutants and a requirement to take additional measures to control non-point source pollution (e.g., storm water runoff) at facilities that discharge into waters for which TMDLs are established. Because the effect on the Company will depend on the actual TMDLs and permit limitations established by the implementing agency, it is not possible to determine the effect on the Company at this time.

Several major pieces of environmental legislation are periodically considered for reauthorization or amendment by Congress. These include: the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; and the Endangered Species Act.

Compliance with possible additional federal or state legislation or regulations related to global climate change, electromagnetic fields, or other environmental and health concerns could also significantly affect the Company. The impact of any new legislation, changes to existing legislation, or environmental regulations could affect many areas of the Company's operations. The full impact of any such changes cannot, however, be determined at this time.

FERC Matters

Transmission

In December 1999, the Federal Energy Regulatory Commission (FERC) issued its final rule (Order 2000) on Regional Transmission Organizations (RTOs). Order 2000 encouraged utilities owning transmission systems to form RTOs on a voluntary basis. Through Southern Company, the Company worked with a number of utilities in the Southeast to develop a for-profit RTO known as SeTrans. In 2002, the sponsors of SeTrans established a Stakeholder Advisory Committee to provide input into the development of the RTO from other sectors of the electric industry, as well as consumers. During the development of SeTrans, state regulatory authorities expressed concern over certain aspects of the FERC's policies regarding RTOs. In December 2003, the SeTrans sponsors announced that they would suspend work on SeTrans because the regulated utility participants, including Southern Company's retail operating companies, had determined that it was highly unlikely to obtain support of both federal and state regulatory authorities. Any impact of the FERC's rule on the Company will depend on the regulatory reaction to the suspension of SeTrans and future developments, which cannot now be determined.

In July 2002, the FERC issued a notice of proposed rulemaking regarding open access transmission service and standard electricity market design. The proposal, if adopted, would among other things: (1) require transmission assets of jurisdictional utilities to be operated by an independent entity; (2) establish a standard market design; (3) establish a single type of transmission service that applies to all customers; (4) assert jurisdiction over the transmission component of bundled retail service; (5) establish a generation reserve margin; (6) establish bid caps for day ahead and spot energy markets; and (7) revise the FERC policy on the pricing of transmission expansions. Comments on the proposal were submitted by many interested parties, including Southern Company and the Company, and the FERC has indicated that it has revised certain aspects of the proposal in response to public comments. Proposed energy legislation would prohibit the FERC from issuing the final rule before October 31, 2006, and from making any final rule effective before December 31, 2006. That legislation has been approved by the House of Representatives but remains pending before the Senate. Passage of the legislation now appears in doubt. It is uncertain whether in the absence of legislation the FERC will move forward with any part or all of the proposed rule. Any impact of this proposal on the Company will depend on the form in which the final rule may be ultimately adopted. However, the Company's financial statements could be adversely affected by changes in the transmission regulatory structure in its regional power market.

Hydro Relicensing

In 2002, the Company initiated the relicensing process for the Company's seven hydroelectric projects on the Coosa River (Weiss, Henry, Logan Martin, Lay, Mitchell, Jordan, and Bouldin) and the Smith and Bankhead Projects on the Warrior River. The FERC licenses for all of these nine projects expire in 2007. Upon or after the expiration of each license, the United States Government, by act of Congress, may take over the project or the FERC may relicense the project either to the original licensee or to a new licensee. The FERC may grant relicenses subject to certain requirements that could result in additional costs to the Company.

Market-Based Rate Authority

The Company has obtained FERC approval to sell power to nonaffiliates at market-based prices under specific contracts. Through SCS, as agent, the Company also has FERC authority to make short-term opportunity sales at market rates. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate. In November 2001, the FERC modified the test it uses to consider utilities' applications to charge market-based rates and adopted a new test called the Supply Margin Assessment (SMA). The FERC applied the SMA to several utilities, including Southern Company's retail operating companies, and found them to be "pivotal suppliers" in their service areas and ordered the implementation of several mitigation measures. SCS, on behalf of the retail operating companies, sought rehearing of the FERC order, and the FERC delayed the implementation of certain mitigation measures. SCS, on behalf of the retail operating companies, submitted comments to the FERC in 2002 regarding these issues. In December 2003, the FERC issued a staff paper discussing alternatives and held a technical conference in January 2004. The Company anticipates that the FERC will address the requests for rehearing in the near future. Regardless of the outcome of the SMA proposal, the FERC retains the ability to modify or withdraw the authorization for any seller to sell at market-based rates, if it determines that the underlying conditions for having such authority are no longer applicable. The final outcome of this matter will depend on the form in which the SMA test and mitigation measures rules may be ultimately adopted and cannot be determined at this time.

Other Matters

In accordance with Financial Accounting Standards Board (FASB) Statement No. 87, Employers' Accounting for Pensions, the Company recorded non-cash pension income, before tax, of approximately $52 million, $56 million, and $57 million in 2003, 2002, and 2001, respectively. Future pension income is dependent on several factors including trust earnings and changes to the plan. The decline in pension income is expected to continue and become an expense as early as 2011. Postretirement benefit costs for the Company were $23 million, $23 million, and $21 million in 2003, 2002, and 2001, respectively, and are expected to continue to trend upward. A portion of pension income and postretirement benefit costs is capitalized based on construction-related labor charges. Pension income or expense and postretirement benefit costs are a component of the regulated rates and generally do not have a long-term effect on net income. For more information regarding pension and postretirement benefits, see Note 2 to the financial statements.

Prices for electricity provided by the Company to retail customers are set by the Alabama PSC under cost-based regulatory principles. Rates for the Company can be adjusted periodically within certain limitations based on earned retail rate of return compared with an allowed return range. Increases in retail rates of 2 percent were effective in both April 2002 and October 2001 in accordance with the Rate Stabilization Equalization plan.

The rates also provide for adjustments to recognize the placing of new generating facilities into retail service and the recovery of retail costs associated with certificated purchased power agreements (PPAs) under Rate CNP (Certificated New Plant). Effective July 2001, the Company's retail rates were adjusted by 0.6 percent under Rate CNP to recover costs for Plant Barry Unit 7, which was placed into commercial operation on May 1, 2001. Effective July 2003, the Company's retail rates were adjusted by approximately 2.6% under Rate CNP as a result of two new certificated PPAs that began in June 2003. See Note 3 to the financial statements under "Retail Rate Adjustment Procedures" for additional information.

On December 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act). The Medicare Act introduces a prescription drug benefit for Medicare-eligible retirees starting in 2006, as well as a federal subsidy to plan sponsors like the Company that provide prescription drug benefits. In accordance with FASB Staff Position No. 106-1, the Company has elected to defer recognizing the effects of the Medicare Act for its postretirement plans under FASB Statement No. 106, Employers' Accounting for Postretirement Benefits Other than Pension until authoritative guidance on accounting for the federal subsidy is issued or until a significant event occurs that would require remeasurement of the plans' assets and obligations. The Company anticipates that the benefits it pays after 2006 will be lower as a result of the Medicare Act; however, the retiree medical obligations and costs reported in Note 2 to the financial statements do not reflect these changes. The final accounting guidance could require changes to previously reported information.

Nuclear security legislation was recently introduced and considered in Congress both as a free-standing bill in the Senate and as a part of comprehensive energy legislation in a House-Senate Conference Report. Neither of the proposals has been enacted. The Nuclear Regulatory Commission (NRC) also ordered additional security measures for licensees in 2003. The Company is in the process of implementation and must be in full compliance with these orders by October 29, 2004. The requirements of the latest orders will have an impact on the Company's Plant Farley and will result in increased operation and maintenance expenses as well as additional capital expenditures. The precise impact of the new requirements will depend upon the details of the implementation of the new requirements, which have not been finalized.

The Company filed an application with the NRC in September 2003 to extend the operating license for Plant Farley for an additional 20 years. If approved by the NRC, the Company's depreciation and amortization expense could be reduced pending approval by the Alabama PSC.

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

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with accounting principles generally accepted in the United States. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has discussed the development and selection of the critical accounting policies and estimates described below with the Controls and Compliance Committee of the Company's Board of Directors and the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

The Company is subject to retail regulation by the Alabama PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies FASB Statement No. 71, Accounting for the Effects of Certain Types of Regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of Statement No. 71 has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation, nuclear decommissioning, and pension and post-retirement benefits have less of a direct impact on the Company's results of operations than they would on a non-regulated company.

As reflected in Note 1 to the financial statements under "Regulatory Assets and Liabilities," significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and liabilities based on applicable regulatory guidelines. However, adverse legislation and judicial or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that potentially subject it to environmental, litigation, income tax, and other risks. See "Future Earnings Potential" and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and records reserves for those matters where a loss is considered probable and reasonably estimable in accordance with generally accepted accounting principles. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's financial statements. These events or conditions include the following:

- Changes in existing state or federal regulation by governmental authorities having jurisdiction over air quality, water quality, control of toxic substances, hazardous and solid wastes, and other environmental matters.
- Changes in existing income tax regulations or changes in Internal Revenue Service interpretations of existing regulations.
- Identification of sites that require environmental remediation or the filing of other complaints in which the Company may be asserted to be a potentially responsible party.
- Identification and evaluation of other potential lawsuits or complaints in which the Company may be named as a defendant.
- Resolution or progression of existing matters through the legislative process, the court systems, or the EPA.

New Accounting Standards

Prior to January 2003, the Company accrued for the ultimate cost of retiring most long-lived assets over the life of the related asset through depreciation expense. FASB Statement No. 143, Accounting for Asset Retirement Obligations established new accounting and reporting standards for legal obligations associated with the ultimate cost of retiring long-lived assets. The present value of the ultimate costs of an asset's future retirement is recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. Additionally, non-regulated companies are no longer permitted to continue accruing future retirement costs for long-lived assets that they do not have a legal obligation to retire. For more information regarding the impact of adopting this standard effective January 1, 2003, see Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal."

FASB Statement No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities, which further amends and clarifies the accounting and reporting for derivative instruments, became effective generally for financial instruments entered into or modified after June 30, 2003. Current interpretations of Statement No. 149 indicate that certain electricity forward transactions subject to unplanned netting -- including those typically referred to as "book outs" -- may only qualify as cash flow hedges if an entity can demonstrate that physical delivery or receipt of power occurred. The Company's forward electricity contracts continue to be exempt from fair value accounting requirements or to qualify as cash flow hedges, with the related gains and losses deferred in other comprehensive income. The implementation of Statement No. 149 did not have a material effect on the Company's financial statements.

In July 2003, the Emerging Issues Task Force (EITF) of FASB issued EITF No. 03-11, which became effective on October 1, 2003. The standard addresses the reporting of realized gains and losses on derivative instruments and is being interpreted to require book outs to be recorded on a net basis in operating revenues. Adoption of this standard did not have a material impact on the Company's financial statements.

FASB Interpretation No. 46, Consolidation of Variable Interest Entities, which was originally issued in January 2003, requires the primary beneficiary of a variable interest entity to consolidate the related assets and liabilities. In December 2003, the FASB revised Interpretation No. 46 and deferred the effective date until March 31, 2004 for interests held in variable interest entities other than special purpose entities.

Current analysis indicates that the trusts established by the Company to issue preferred securities are variable interest entities under Interpretation No. 46, and that the

Company is not the primary beneficiary of these trusts. If this conclusion is finalized, effective March 31, 2004, the trust assets and liabilities -- including the preferred securities issued by the trusts -- will be deconsolidated. The investments in the trusts and the loans from the trusts to the Company will be reflected as equity method investments and as long-term notes payable to affiliates, respectively, on the Balance Sheets. Based on December 31, 2003 values, this treatment would result in an increase of approximately $9 million to both total assets and total liabilities. See Note 6 to the financial statements under "Mandatorily Redeemable Preferred Securities" for additional information.

In May 2003, the FASB issued Statement No. 150, Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity, which requires classification of certain financial instruments within its scope, including shares that are mandatorily redeemable, as liabilities. Statement No. 150 was effective for financial instruments entered into or modified after May 31, 2003, and otherwise on July 1, 2003. In accordance with Statement No. 150, mandatorily redeemable preferred securities are reflected in the Balance Sheets as liabilities. The adoption of Statement No. 150 had no impact on the Statements of Income and Cash Flows.

FINANCIAL CONDITION AND LIQUIDITY

Overview

Over the last several years, the Company's financial condition has remained stable with emphasis on cost control measures combined with significantly lower cost of capital, achieved through the refinancing and/or redemption of higher-cost long-term debt and preferred stock. The Company operated at high levels of reliability while achieving industry-leading customer satisfaction levels and continuing to have retail prices below the national average.

The Company had gross property additions of $649 million in 2003. The majority of funds needed for gross property additions for the last several years have been provided from operating activities. The Statements of Cash Flows provide additional details.

The Company's ratio of common equity to total capitalization -- including short-term debt -- was 43.3 percent in 2003, 42.6 percent in 2002, and 42.8 percent in 2001. See Note 6 to the financial statements for additional information.

Sources of Capital

The Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows. However, the type and timing of any financings -- if needed -- will depend on market conditions and regulatory approval. In recent years, financings primarily have utilized unsecured debt and preferred securities.

The Company obtains financing separately without credit support from any affiliate. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company. In accordance with the Public Utility Holding Company Act, most loans between affiliated companies must be approved in advance by the Securities and Exchange Commission (SEC).

The Company's current liabilities exceed current assets because of securities due within one year. The Company intends to refinance debt that comes due during 2004.

To meet short-term cash needs and contingencies, the Company has various internal and external sources of liquidity. At the beginning of 2004, the Company had approximately $43 million of cash and cash equivalents and $865 million of unused credit arrangements with banks, as shown in the following table. In addition, the Company has substantial cash flow from operating activities and access to the capital markets, including commercial paper programs, to meet liquidity needs. Cash flows from operating activities were $1,118 million in 2003, $973 million in 2002, and $843 million in 2001.

At the beginning of 2004, bank credit arrangements are as follows:

		Expires	
Total	Unused	2004	2005 & Beyond
	(in millions)		
$865	$865	$865	-

Approximately $450 million of the credit facilities expiring in 2004 allow for the execution of term loans for an additional two-year period and $245 million allow for the execution for a one-year period. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper and extendible commercial notes at the request and for the benefit of the Company and the other Southern Company retail operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company and are not commingled with proceeds from such issuances for the benefit of any other operating company. The obligations of each company under these arrangements are several; there is no cross affiliate credit support. At December 31, 2003, the Company had no commercial paper outstanding.

Financing Activities

In 2003, the Company's financing costs decreased due to lower interest rates despite the issuance of an increased amount of senior securities during the year. New issues during 2001 through 2003 totaled $3.3 billion and retirement or repayment of higher-cost securities totaled $2.8 billion.

Composite financing rates for long-term debt, preferred stock, and preferred securities for the years 2001 through 2003, as of year-end, were as follows:

	2003	2002	2001
Long-term debt interest rate	**4.42%**	5.05%	5.72%
Preferred securities distribution rate	**5.25**	5.25	6.96
Preferred stock dividend rate	**5.10**	5.17	4.79

Subsequent to December 31, 2003, the Company has entered into interest rate hedging transactions related to the anticipated refinancing of $470 million of securities due within one year. Also, an additional $300 million of securities have been issued for other general corporate purposes including repayment of outstanding short-term indebtedness and the funding of the Company's continuous construction program.

Credit Rating Risk

The Company does not have any credit agreements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are contracts that could require collateral -- but not accelerated payment -- in the event of a credit rating change to below investment grade. These contracts are primarily for physical electricity purchases and sales, fixed-price physical gas purchases, and agreements covering interest rate swaps. At December 31, 2003, the maximum potential collateral requirements under the electricity purchase and sale contracts were approximately $26.7 million. Generally, collateral may be provided for by a Company guaranty, a letter of credit, or cash. At December 31, 2003, there were no material collateral requirements for the gas purchase contracts or other financial instrument agreements.

Market Price Risk

Due to cost-based rate regulations, the Company has limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and hedging practices. Company policy is that derivatives are to be used primarily for hedging purposes. Derivative positions are monitored using techniques that include market valuation and sensitivity analysis.

To mitigate exposure to interest rates, the Company has entered into interest rate swaps that have been designated as hedges. The weighted average interest rate on outstanding variable long-term debt, that has not been hedged at December 31, 2003 was 1.38 percent. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $0.5 million at December 31, 2003. The Company is not aware of any facts or circumstances that would significantly affect such exposures in the near term. For further information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

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, and, to a lesser extent, into similar contracts for gas purchases.

In addition, in October 2001, the Alabama PSC approved a revision to the Company's Rate ECR (Energy Cost Recovery) allowing the recovery of specific costs associated with the sales of natural gas that become necessary due to operating considerations at its electric generating facilities. This revision also includes the cost of financial instruments used for hedging market price risk up to 75 percent of the budgeted annual amount of natural gas purchases. The Company may not engage in natural gas hedging activities that extend beyond a rolling 42-month window. Also, the premiums paid for natural gas financial options may not exceed 5 percent of the Company's natural gas budget for that year.

At December 31, 2003, exposure from these activities was not material to the Company's financial position, results of operations, or cash flows. The changes in fair value of derivative energy contracts and year-end valuations were as follows:

	Changes in Fair Value	
	2003	2002
	(in thousands)	
Contracts beginning of year	**$ 21,402**	$ 214
Contracts realized or settled	**(38,809)**	(21,088)
New contracts at inception	**-**	-
Changes in valuation techniques	**-**	-
Current period changes	**23,820**	42,276
Contracts end of year	**$ 6,413**	$ 21,402

	Source of 2003 Year-End Valuation Prices		
	Total	Maturity	
	Fair Value	2004	2005-2006
	(in thousands)		
Actively quoted	**$6,413**	**$7,803**	**$(1,390)**
External sources	**-**	**-**	**-**
Models and other methods	**-**	**-**	**-**
Contracts end of Year	**$6,413**	**$7,803**	**$(1,390)**

Unrealized gains and losses from mark to market adjustments on derivative contracts related to the Company's fuel hedging programs are recorded as regulatory assets and liabilities. Realized gains and losses from these programs are included in fuel expense and are recovered through the Company's fuel cost recovery clause. Gains and losses on derivative contracts that are not designated as hedges are recognized in the income statement as incurred. At December 31, 2003, the fair value of derivative energy contracts was reflected in the financial statements as follows:

	Amounts
	(in thousands)
Regulatory liabilities, net	**$6,402**
Net income	**11**
Total fair value	**$6,413**

Unrealized pre-tax gains (losses) on energy contracts of $(0.1) million, $(2.0) million, and $2.0 million were recognized in income in 2003, 2002, and 2001, respectively. The Company is exposed to market price risk in the event of nonperformance by counterparties to the derivative energy contracts. The Company's policy is to enter into agreements with counterparties that have investment grade credit ratings by Moody's and Standard & Poor's or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to be $791 million for 2004, $863 million for 2005, and $884 million for 2006. Over the next three years, the Company estimates spending $713 million on environmental related additions (including $358 million on Selective Catalytic Reduction facilities), $267 million on Plant Farley (including $155 million for nuclear fuel, $29 million on cooling towers and $26 million on replacing reactor vessel heads), $701 million on distribution facilities, and $402 million on transmission additions. See Note 7 to the financial statements under "Construction Program" for additional details.

Actual construction costs may vary from this estimate because of changes in such factors as: business conditions; environmental regulations; nuclear plant regulations; FERC rules and transmission regulations; load projections; the cost and efficiency of construction labor, equipment, and materials; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

In addition to the funds required for the Company's construction program, approximately $1.5 billion will be required by the end of 2006 for maturities of long-term debt. The Company plans to continue, when economically feasible, to retire higher cost debt, preferred securities, and preferred stock and replace these obligations with lower-cost capital if market conditions permit.

As a result of requirements by the NRC, the Company has established external trust funds for the purpose of funding nuclear decommissioning costs. Annual provisions for nuclear decommissioning are based on an annuity method as approved by the Alabama PSC. The amount expensed in 2003 was $18 million. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning." Additionally, as discussed in Note 1 to the financial statements under "Revenues and Fuel Costs," in 1993, the DOE implemented a special assessment over a 15-year period on utilities with nuclear plants to be used for the decontamination and decommissioning of its nuclear fuel enrichment facilities.

In 1994, the Company also established an external trust fund for postretirement benefits as ordered by the Alabama PSC. The cumulative effect of funding these items over a long period will diminish internally funded capital and may require capital from other sources. For additional information, see Note 2 to the financial statements under "Postretirement Benefits."

The capital requirements, lease obligations, purchase commitments, and trust requirements – discussed above and in the financial statements – are summarized as follows: (See Notes 1, 6, and 7 to the financial statements for additional information.)

	2004	2005-2006	2007-2008	After 2008	Total
			(in millions)		
Long-term debt and preferred securities[(a)] --					
Principal	$ 526.0	$ 940.5	$ 610.0	$2,135.1	$ 4,211.6
Interest and distributions	188.8	302.5	241.9	2,048.0	2,781.2
Preferred stock dividends[(b)]	19.0	38.0	38.0	-	95.0
Operating leases	29.7	42.7	13.5	35.2	121.1
Purchase commitments[(c)] --					
Capital[(d)]	778.0	1,729.1	-	-	2,507.1
Coal and nuclear fuel	750.4	951.0	582.7	-	2,284.1
Natural gas[(e)]	318.3	338.5	133.1	107.7	897.6
Purchased power	85.0	175.0	178.0	129.0	567.0
Long-term service agreements	18.3	17.8	57.6	119.2	212.9
Trusts --					
Nuclear decommissioning	20.3	40.6	40.6	222.5	324.0
Postretirement benefits[(f)]	4.2	48.5	-	-	52.7
DOE assessments	4.4	8.7	-	-	13.1
Total	$2,742.4	$4,632.9	$1,895.4	$4,796.7	$14,067.4

(a) All amounts are reflected based on final maturity dates. The Company will continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2004, as reflected in the Statements of Capitalization.

(b) Preferred stock does not mature; therefore, amounts are provided for the next five years only.

(c) The Company generally does not enter into non-cancelable commitments for other operation and maintenance expenditures. Total other operation and maintenance expenses for the last three years were $921 million, $854 million, and $784 million, respectively.

(d) The Company forecasts capital expenditures over a three-year period. Amounts represent current estimates of total expenditures excluding those amounts related to contractual purchase commitments for uranium and nuclear fuel conversion, enrichment, and fabrication services. At December 31, 2003, significant purchase commitments were outstanding in connection with the construction program.

(e) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on the New York Mercantile future prices at December 31, 2003.

(f) The Company forecasts post-retirement trust contributions over a three-year period. No contributions related to the Company's pension trust are currently expected during this period. See Note 2 to the financial statements for additional information related to the pension plan.

Cautionary Statement Regarding Forward-Looking Information

The Company's 2003 Annual Report includes forward-looking statements in addition to historical information. Forward-looking information includes, among other things, statements concerning the Company's estimated construction and other expenditures, and the Company's projections for energy sales and its goals for future generating capacity and earnings growth. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "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, tax, 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, regulatory investigations, proceedings or inquiries, including the pending EPA civil action against the Company;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- the impact of fluctuations in commodity prices, interest rates, and customer demand;
- available sources and costs of fuels;
- ability to control costs;
- investment performance of the Company's employee benefit plans;
- advances in technology;
- state and federal rate regulations and pending and future rate cases and negotiations;
- effects of and changes in political, legal, and economic conditions and developments in the United States, including the current soft economy;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due;
- the ability to obtain new short- and long-term contracts with neighboring utilities;
- the direct or indirect effects on the Company's business resulting from the terrorist incidents on September 11, 2001, or any similar incidents or responses to such incidents;
- financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- weather and other natural phenomena;
- the direct or indirect effects on the Company's business resulting from the August 2003 power outage in the Northeast, or any similar incidents;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed from time to time by the Company with the SEC.

STATEMENTS OF INCOME
For the Years Ended December 31, 2003, 2002, and 2001
Alabama Power Company 2003 Annual Report

	2003	2002	2001
		(in thousands)	
Operating Revenues:			
Retail sales	**$3,051,463**	$2,951,217	$2,747,673
Sales for resale --			
Non-affiliates	**487,456**	474,291	485,974
Affiliates	**277,287**	188,163	245,189
Other revenues	**143,955**	96,862	107,554
Total operating revenues	**3,960,161**	3,710,533	3,586,390
Operating Expenses:			
Fuel	**1,067,821**	969,521	1,000,828
Purchased power --			
Non-affiliates	**110,885**	90,998	144,991
Affiliates	**204,353**	158,121	147,967
Other operations	**611,418**	574,979	508,264
Maintenance	**309,451**	279,406	275,510
Depreciation and amortization	**412,919**	398,428	383,473
Taxes other than income taxes	**228,414**	216,919	214,665
Total operating expenses	**2,945,261**	2,688,372	2,675,698
Operating Income	**1,014,900**	1,022,161	910,692
Other Income and (Expense):			
Allowance for equity funds used during construction	**12,594**	11,168	7,092
Interest income	**15,220**	13,991	15,101
Interest expense, net of amounts capitalized	**(214,302)**	(225,706)	(246,436)
Distributions on mandatorily redeemable preferred securities	**(15,255)**	(24,599)	(24,775)
Other income (expense), net	**(31,702)**	(28,785)	(11,177)
Total other income and (expense)	**(233,445)**	(253,931)	(260,195)
Earnings Before Income Taxes	**781,455**	768,230	650,497
Income taxes	**290,378**	292,436	248,597
Earnings Before Cumulative Effect of Accounting Change	**491,077**	475,794	401,900
Cumulative effect of accounting change-- less income taxes of $215 thousand	**-**	-	353
Net Income	**491,077**	475,794	402,253
Dividends on Preferred Stock	**18,267**	14,439	15,524
Net Income After Dividends on Preferred Stock	**$ 472,810**	$ 461,355	$ 386,729

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

BALANCE SHEETS
At December 31, 2003 and 2002
Alabama Power Company 2003 Annual Report

Assets	2003	2002
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 42,752**	$ 22,685
Receivables --		
Customer accounts receivable	**240,562**	240,052
Unbilled revenues	**95,953**	89,336
Other accounts and notes receivable	**53,547**	47,535
Affiliated companies	**48,876**	74,099
Accumulated provision for uncollectible accounts	**(4,756)**	(4,827)
Fossil fuel stock, at average cost	**86,993**	73,742
Vacation pay	**35,530**	33,901
Materials and supplies, at average cost	**211,690**	207,872
Prepaid expenses	**44,608**	40,411
Other	**19,454**	27,210
Total current assets	**875,209**	852,016
Property, Plant, and Equipment:		
In service	**14,224,117**	13,506,170
Less accumulated provision for depreciation	**4,905,920**	4,658,803
	9,318,197	8,847,367
Nuclear fuel, at amortized cost	**93,611**	103,088
Construction work in progress	**321,316**	458,375
Total property, plant, and equipment	**9,733,124**	9,408,830
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**47,811**	45,553
Nuclear decommissioning trusts, at fair value	**384,574**	292,297
Other	**16,992**	16,477
Total other property and investments	**449,377**	354,327
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**321,077**	327,276
Prepaid pension costs	**446,256**	389,793
Unamortized loss on reacquired debt	**110,946**	103,819
Department of Energy assessments	**13,092**	17,144
Other	**121,543**	138,461
Total deferred charges and other assets	**1,012,914**	976,493
Total Assets	**$12,070,624**	$11,591,666

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

BALANCE SHEETS
At December 31, 2003 and 2002
Alabama Power Company 2003 Annual Report

Liabilities and Stockholder's Equity	2003	2002
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$ 526,019**	$ 1,117,945
Notes payable	-	36,991
Accounts payable --		
Affiliated	**135,017**	109,790
Other	**162,314**	141,251
Customer deposits	**47,507**	44,410
Accrued taxes --		
Income taxes	**83,544**	80,438
Other	**22,273**	20,561
Accrued interest	**46,489**	36,344
Accrued vacation pay	**35,530**	33,901
Accrued compensation	**75,620**	74,099
Other	**34,513**	49,715
Total current liabilities	**1,168,826**	1,745,445
Long-term debt (See accompanying statements)	**3,377,148**	2,872,609
Mandatorily redeemable preferred securities (See accompanying statements)	**300,000**	300,000
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**1,571,076**	1,436,559
Deferred credits related to income taxes	**162,168**	177,205
Accumulated deferred investment tax credits	**216,309**	227,270
Employee benefit obligations	**180,960**	156,526
Deferred capacity revenues	**36,567**	46,155
Asset retirement obligations	**358,759**	-
Asset retirement obligation regulatory liability	**127,346**	-
Other cost of removal obligations	**574,445**	884,613
Miscellaneous regulatory liabilities	**86,323**	79,545
Other	**37,525**	40,487
Total deferred credits and other liabilities	**3,351,478**	3,048,360
Total liabilities	**8,197,452**	7,966,414
Cumulative preferred stock (See accompanying statements)	**372,512**	247,512
Common stockholder's equity (See accompanying statements)	**3,500,660**	3,377,740
Total Liabilities and Stockholder's Equity	**$12,070,624**	$11,591,666
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2003 and 2002
Alabama Power Company 2003 Annual Report

	2003	2002	**2003**	2002
	(in thousands)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable --				
Variable rate (1.525% at 1/1/03) due 2003	**$ -**	$ 517,000		
5.35% to 7.85% due 2003	**-**	406,200		
4.875% to 7.125% due 2004	**525,000**	525,000		
5.49% due November 1, 2005	**225,000**	225,000		
2.65% to 2.80% due 2006	**520,000**	-		
Floating rate (1.37% at 1/1/04) due 2006	**195,000**	-		
7.125% due October 1, 2007	**200,000**	200,000		
3.125% to 5.375% due 2008	**410,000**	160,000		
4.70% to 6.75% due 2010-2039	**1,275,000**	1,408,800		
Total long-term notes payable	**3,350,000**	3,442,000		
Other long-term debt --				
Pollution control revenue bonds --				
Collateralized:				
5.50% due 2024	**24,400**	24,400		
Variable rates (1.27% to 1.33% at 1/1/04) due 2015-2017	**89,800**	89,800		
Non-collateralized:				
Variable rates (1.23% to 1.45% at 1/1/04) due 2021-2031	**445,940**	445,940		
Total other long-term debt	**560,140**	560,140		
Capitalized lease obligations	**1,497**	2,439		
Unamortized debt premium (discount), net	**(8,470)**	(14,025)		
Total long-term debt (annual interest requirement -- $173.0 million)	**3,903,167**	3,990,554		
Less amount due within one year	**526,019**	1,117,945		
Long-term debt excluding amount due within one year	**$3,377,148**	$2,872,609	**44.7%**	42.3%

STATEMENTS OF CAPITALIZATION (continued)
At December 31, 2003 and 2002
Alabama Power Company 2003 Annual Report

	2003	2002	2003	2002
	(in thousands)		*(percent of total)*	
Mandatorily Redeemable Preferred Securities:				
$1,000 liquidation value due 2042 --				
4.75% through 2007*	**$ 100,000**	$ 100,000		
5.50% through 2009*	**200,000**	200,000		
Total (annual distribution requirement -- $15.8 million)	**300,000**	300,000	**4.0**	4.4
Cumulative Preferred Stock:				
$100 par or stated value --				
4.20% to 4.92%	**47,512**	47,512		
$25 par or stated value --				
5.20% to 5.83%	**200,000**	200,000		
$100,000 stated value --				
4.95%	**125,000**	-		
Total (annual dividend requirement -- $19.0 million)	**372,512**	247,512	**4.9**	3.6
Common Stockholder's Equity:				
Common stock, par value $40 per share --				
Authorized - 15,000,000 shares in 2003 and 6,000,000 shares in 2002				
Outstanding - 7,250,000 shares in 2003 and 6,000,000 shares in 2002				
Par value	**290,000**	240,000		
Paid-in capital	**1,926,970**	1,900,464		
Premium on Preferred Stock	**99**	99		
Retained earnings	**1,291,558**	1,250,594		
Accumulated other comprehensive income (loss)	**(7,967)**	(13,417)		
Total common stockholder's equity	**3,500,660**	3,377,740	**46.4**	49.7
Total Capitalization	**$7,550,320**	$6,797,861	**100.0%**	100.0%

*The fixed rates thereafter are determined through remarketings for specific periods of varying length or at floating rates determined by reference to 3-month LIBOR plus 2.91% and 3.10%, respectively.

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

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2003, 2002, and 2001
Alabama Power Company 2003 Annual Report

	Common Stock	Paid-In Capital	Premium on Preferred Stock	Retained Earnings	Other Comprehensive Income (loss)	Total
			(in thousands)			
Balance at December 31, 2000	$224,358	$1,743,363	$99	$1,227,952	$ -	$3,195,772
Net income after dividends on preferred stock	-	-	-	386,729	-	386,729
Issuance of common stock	15,642	-	-	-	-	15,642
Capital contributions from parent company	-	107,313	-	-	-	107,313
Cash dividends on common stock	-	-	-	(393,900)	-	(393,900)
Other	-	-	-	(679)	-	(679)
Balance at December 31, 2001	240,000	1,850,676	99	1,220,102	-	3,310,877
Net income after dividends on preferred stock	-	-	-	461,355	-	461,355
Capital contributions from parent company	-	49,788	-	-	-	49,788
Other comprehensive income (loss)	-	-	-	-	(13,417)	(13,417)
Cash dividends on common stock	-	-	-	(431,000)	-	(431,000)
Other	-	-	-	137	-	137
Balance at December 31, 2002	**240,000**	**1,900,464**	**99**	**1,250,594**	**(13,417)**	**3,377,740**
Net income after dividends on preferred stock	**-**	**-**	**-**	**472,810**	**-**	**472,810**
Issuance of common stock	**50,000**	**-**	**-**	**-**	**-**	**50,000**
Capital contributions from parent company	**-**	**26,506**	**-**	**-**	**-**	**26,506**
Other comprehensive income (loss)	**-**	**-**	**-**	**-**	**5,450**	**5,450**
Cash dividends on common stock	**-**	**-**	**-**	**(430,200)**	**-**	**(430,200)**
Other	**-**	**-**	**-**	**(1,646)**	**-**	**(1,646)**
Balance at December 31, 2003	**$290,000**	**$1,926,970**	**$99**	**$1,291,558**	**$ (7,967)**	**$3,500,660**

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2003, 2002, and 2001
Alabama Power Company 2003 Annual Report

	2003	2002	2001
		(in thousands)	
Net income after dividends on preferred stock	**$472,810**	$461,355	$386,729
Other comprehensive income (loss):			
Change in additional minimum pension liability, net of tax of $(2,301) and $(2,536), respectively	**(3,785)**	(4,172)	-
Changes in fair value of qualifying hedges, net of tax of $1,330 and $(6,430), respectively	**2,188**	(10,576)	-
Less: Reclassification adjustment for amounts included in net income, net of tax of $4,285 and $810, respectively	**7,047**	1,331	-
Total other comprehensive income (loss)	**5,450**	(13,417)	-
Comprehensive Income	**$478,260**	$447,938	$386,729

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2003, 2002, and 2001
Alabama Power Company 2003 Annual Report

	2003	2002	2001
		(in thousands)	
Operating Activities:			
Net income	**$491,077**	$ 475,794	$ 402,253
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization	**467,085**	442,660	437,490
Deferred income taxes and investment tax credits, net	**153,154**	48,828	(21,569)
Deferred capacity revenues	**(9,589)**	(8,099)	-
Pension, postretirement, and other employee benefits	**(32,029)**	(34,977)	(58,118)
Tax benefit of stock options	**8,680**	6,670	-
Settlement of interest rate hedges	**(7,957)**	-	-
Other, net	**11,393**	4,663	(64,533)
Changes in certain current assets and liabilities --			
Receivables, net	**7,134**	(50,423)	88,325
Fossil fuel stock	**(13,251)**	25,535	(38,663)
Materials and supplies	**(4,651)**	3,728	(13,025)
Other current assets	**(953)**	1,479	(15,474)
Accounts payable	**50,928**	1,068	(83,077)
Accrued taxes	**(33,507)**	(40,922)	46,187
Energy cost recovery, retail	**1,195**	84,429	154,320
Other current liabilities	**29,385**	12,730	3,790
Net cash provided from operating activities	**1,118,094**	973,163	837,906
Investing Activities:			
Gross property additions	**(648,560)**	(634,094)	(635,540)
Cost of removal net of salvage	**(35,440)**	(32,111)	(37,304)
Sales of property	**-**	-	102,068
Other	**(13,763)**	(6,151)	2,533
Net cash used for investing activities	**(697,763)**	(672,356)	(568,243)
Financing Activities:			
Increase (decrease) in notes payable, net	**(36,991)**	26,994	(271,347)
Proceeds --			
Pollution control bonds	**-**	-	35,000
Senior notes	**1,415,000**	975,000	442,000
Mandatorily redeemable preferred securities	**-**	300,000	-
Preferred stock	**125,000**	-	-
Common stock	**50,000**	-	15,642
Capital contributions from parent company	**17,826**	43,118	107,313
Redemptions --			
First mortgage bonds	**-**	(350,000)	(138,991)
Pollution control bonds	**-**	-	(15,000)
Senior notes	**(1,507,000)**	(415,602)	(3,179)
Other long-term debt	**(943)**	(883)	(842)
Mandatorily redeemable preferred securities	**-**	(347,000)	-
Preferred stock	**-**	(70,000)	-
Payment of preferred stock dividends	**(18,181)**	(14,176)	(14,942)
Payment of common stock dividends	**(430,200)**	(431,000)	(393,900)
Other	**(14,775)**	(30,329)	(9,908)
Net cash used for financing activities	**(400,264)**	(313,878)	(248,154)
Net Change in Cash and Cash Equivalents	**20,067**	(13,071)	21,509
Cash and Cash Equivalents at Beginning of Period	**22,685**	35,756	14,247
Cash and Cash Equivalents at End of Period	**$ 42,752**	$ 22,685	$ 35,756
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $6,367, $6,738, and $11,690 capitalized, respectively)	**$185,272**	$230,102	$246,316
Income taxes (net of refunds)	**161,004**	269,043	223,961

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Alabama Power Company (the Company) is a wholly owned subsidiary of Southern Company, which is the parent company of five retail operating companies, Southern Power Company (Southern Power), Southern Company Services (SCS), Southern Communications Services (Southern LINC), Southern Company Gas (Southern Company GAS), Southern Company Holdings (Southern Holdings), Southern Nuclear Operating Company (Southern Nuclear), Southern Telecom, and other direct and indirect subsidiaries. The retail operating companies -- the Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Savannah Electric and Power Company -- provide electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Alabama and to wholesale customers in the Southeast. Southern Power constructs, owns, and manages Southern Company's competitive generation assets and sells electricity at market-based rates in the wholesale market. Contracts among the retail operating companies and Southern Power -- related to jointly-owned generating facilities, interconnecting transmission lines, or the exchange of electric power -- are regulated by the Federal Energy Regulatory Commission (FERC) and/or the Securities and Exchange Commission (SEC). SCS -- the system service company -- provides, at cost, specialized services to Southern Company and its subsidiary companies. Southern LINC provides digital wireless communications services to the retail operating companies and also markets these services to the public within the Southeast. Southern Telecom provides fiber cable services within the Southeast. Southern Company GAS is a competitive retail natural gas marketer serving customers in Georgia. Southern Holdings is an intermediate holding subsidiary for Southern Company's investments in synthetic fuels and leveraged leases and an energy services business. Southern Nuclear operates and provides services to Southern Company's nuclear power plants, including the Company's Plant Farley.

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 Alabama Public Service Commission (Alabama PSC). The Company follows accounting principles generally accepted in the United States and complies with the accounting policies and practices prescribed by its 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 those estimates.

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

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, purchasing, accounting and statistical analysis, finance and treasury, tax, information resources, marketing, auditing, insurance and pension administration, human resources, systems and procedures, and other services with respect to business and operations and power pool transactions. Costs for these services amounted to $218 million, $218 million, and $183 million during 2003, 2002, and 2001, respectively. Cost allocation methodologies used by SCS are approved by the SEC and management believes they are reasonable.

The Company has an agreement with Southern Nuclear to operate Plant Farley and provide the following nuclear-related services at cost: general executive and advisory services, general operations, management and technical services, administrative services including procurement, accounting, statistical analysis, employee relations, and other services with respect to business and operations. Costs for these services amounted to $153 million, $154 million, and $160 million during 2003, 2002, and 2001, respectively.

The Company has an agreement with Mississippi Power under which Mississippi Power owns a portion of Plant Greene County. The Company operates Plant Greene County, and Mississippi Power reimburses the Company for its proportionate share of expenses which were $6.7 million in 2003, $6.4 million in 2002, and $5.5 million in 2001. See Note 4 for additional information.

Southern Company holds a 30 percent ownership interest in Alabama Fuel Products, LLC (AFP), which produces synthetic fuel. The Company has an agreement with an indirect subsidiary of Southern Company that provides services for AFP. Under this agreement, the Company provides certain accounting functions, including processing and paying fuel transportation invoices, and the Company is reimbursed for its expenses. Amounts billed under this agreement totaled approximately $27.5 million and $34.5 million in 2003 and 2002, respectively. In addition, the Company purchases synthetic fuel from AFP for use at several of the Company's plants. Fuel purchases for 2003 and 2002 totaled $209.2 million and $211.0 million, respectively.

In 2001, the Company had under construction a 1,230 megawatt combined cycle facility in Autaugaville, Alabama (Plant Harris). In June 2001, the Company sold this project to Southern Power. Upon the plant becoming operational in June 2003, the Company entered into an agreement with Southern Power to operate and maintain Plant Harris at cost and provide fuel at cost. In 2003, the Company billed Southern Power $0.8 million for operation and maintenance. Purchased power costs from Plant Harris in 2003 totaled $75.6 million. Additionally, the Company recorded $8.3 million of prepaid capacity expenses included in Other Deferred Charges and Other Assets on the Balance Sheets at December 31, 2003. See Note 3 under "Retail Rate Adjustment Procedures" and Note 7 under "Purchased Power Commitments" for additional information.

Also, see Note 4 for information regarding the Company's ownership in and purchased power agreement with Southern Electric Generating Company (SEGCO).

The retail operating companies, including the Company, Southern Power, and Southern Company GAS, jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements.

Revenues and Fuel Costs

Capacity revenues are generally recognized on a levelized basis over the appropriate contract periods. Energy and other revenues are recognized as services are provided. Unbilled revenues are accrued at the end of each fiscal period. Fuel costs are expensed as the fuel is used. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, 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 regulated 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 continued to average 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 $64 million in 2003, $63 million in 2002, and $58 million in 2001. 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 contract, and the Company is pursuing legal remedies against the government for breach of contract. Sufficient pool storage capacity for spent fuel is available at Plant Farley to maintain full-core discharge capability until the refueling outage scheduled in 2006 for Plant Farley Unit 1 and the refueling outage scheduled in 2008 for Plant Farley Unit 2. Procurement of on-site dry spent fuel storage capacity at Plant Farley is in progress and scheduled for operation in 2005. See Note 7 under "Construction Program" for additional information.

Also, the Energy Policy Act of 1992 required the establishment of a Uranium Enrichment Decontamination and Decommissioning Fund, which is funded in part by a special assessment on utilities with nuclear plants. This assessment is being 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 estimates its remaining liability under this law to be approximately $13 million at December 31, 2003.

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.

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.

Regulatory assets and (liabilities) reflected in the Balance Sheets at December 31 relate to:

	2003	2002	Note
	(in millions)		
Deferred income tax charges	**$ 321**	$ 327	(a)
Loss on reacquired debt	**111**	104	(b)
DOE assessments	**13**	17	(c)
Vacation pay	**36**	34	(d)
Rate CNP under recovery	**17**	-	(e)
Other assets	**13**	17	(e)
Asset retirement obligations	**(127)**	-	(a)
Other cost of removal obligations	**(574)**	(885)	(a)
Deferred income tax credits	**(162)**	(177)	(a)
Natural disaster reserve	**(13)**	(12)	(e)
Nuclear outage	**(14)**	(10)	(e)
Deferred purchased power	**(15)**	-	(e)
Other liabilities	**(5)**	(2)	(e)
Fuel-hedging liabilities	**(6)**	(21)	(f)
Mine reclamation & remediation	**(33)**	(35)	(g)
Total	**$(438)**	$(643)	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Asset retirement and removal liabilities are recorded, deferred income tax assets are recovered, and deferred tax liabilities are amortized over the related property lives, which may range up to 50 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities.

(b) Recovered over the remaining life of the original issue which may range up to 40 years.

(c) Assessments for the decontamination and decommissioning of the DOE nuclear fuel enrichment facilities are recorded annually from 1993 through 2008.

(d) Recorded as earned by employees and recovered as paid, generally within one year.

(e) Recorded and recovered or amortized as approved by the Alabama PSC.

(f) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed two years. Upon final settlement, actual costs incurred are recovered through the fuel cost recovery clauses.

(g) Recovered from customers to settle future costs.

In the event that a portion of the Company's operations is no longer subject to the provisions of FASB 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 values. All regulatory assets and liabilities are reflected in rates.

Depreciation and Amortization

Depreciation of the original cost of depreciable utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.1 percent in 2003 and 3.2 percent in each of 2002 and 2001. 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.

Asset Retirement Obligations and Other Costs of Removal

In accordance with regulatory requirements, prior to January 2003, the Company followed the industry practice of accruing for the ultimate costs of retiring most long-lived assets over the life of the related asset as part of the annual depreciation expense provision. In accordance with SEC requirements, such amounts are reflected on the Balance Sheet as regulatory liabilities. Effective January 1, 2003, the Company adopted FASB Statement No. 143, Accounting for Asset Retirement Obligations. Statement No. 143 establishes new accounting and reporting standards for legal obligations associated with the ultimate costs of retiring long-lived assets. The present value of the ultimate costs of an asset's future retirement must be recorded in the period in which the liability is incurred. The costs must be capitalized as part of the related long-lived asset and depreciated over the asset's useful life. Additionally, Statement No. 143 does not permit the continued accrual of future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. However, the Company has received guidance regarding accounting for the financial statement impacts of Statement No. 143 from the Alabama PSC and will continue to recognize the accumulated removal costs for other obligations as a regulatory liability. Therefore, the Company had no cumulative effect to net income resulting from the adoption of Statement No. 143.

The liability recognized to retire long-lived assets primarily relates to the Company's nuclear facility, Plant Farley. The fair value of assets legally restricted for settling retirement obligations related to nuclear facilities as of December 31, 2003 was $385 million. In addition, the Company has retirement obligations related to various landfill sites and underground storage tanks. The Company has also identified retirement obligations related to certain transmission and distribution facilities, co-generation facilities, certain wireless communication towers, and certain structures authorized by the United States Army Corps of Engineers. However, a liability for the removal of these assets will not be recorded because no reasonable estimate can be made regarding the timing of any related retirements. The Company will continue to recognize in the income statement allowed removal costs in accordance with its regulatory treatment. Any difference between costs recognized under Statement No. 143 and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Alabama PSC, and are reflected in the Balance Sheets. The Company also revised the estimated cost to retire Plant Farley as a result of a new site-specific decommissioning study. The effect of the revision is an increase of $35 million included in asset retirement obligations, with a corresponding increase in property, plant, and equipment. See "Nuclear Decommissioning" for further information on amounts included in rates.

Details of the asset retirement obligations included in the Balance Sheets are as follows:

	2003
	(in millions)
Balance beginning of year	$ -
Liabilities incurred	301
Liabilities settled	-
Accretion	23
Cash flow revisions	35
Balance end of year	$ 359

If Statement No. 143 had been adopted on January 1, 2002, the pro-forma asset retirement obligations would have been $281 million.

Nuclear Decommissioning

The Nuclear Regulatory Commission (NRC) requires all licensees operating commercial nuclear 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. The funds set aside for decommissioning are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and the Alabama PSC, as well as the Internal Revenue Service (IRS). Funds are invested in a tax efficient manner in a diversified mix of equity and fixed income securities. Equity securities typically range from 50 to 75 percent of the funds and fixed income securities from 25 to 50 percent. Amounts previously recorded in internal reserves are being transferred into the external trust funds over periods approved by the Alabama PSC. 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.

Site study cost is the estimate to decommission the facility as of the site study year. The estimated costs of decommissioning, based on the most current study as of December 31, 2003, for Plant Farley were as follows:

Site study year	2003
Decommissioning periods:	
Beginning year	2017
Completion year	2046
	(in millions)
Site study costs:	
Radiated structures	$892
Non-radiated structures	63
Total	$955
Significant assumptions:	
Inflation rate	4.5%
Trust earning rate	7.0

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 NRC requirements, or changes in the assumptions used in making estimates.

Annual provisions for nuclear decommissioning are based on an annuity method as approved by the Alabama PSC. The amount expensed in 2003 and fund balances were as follows:

	(in millions)
Amount expensed in 2003	**$ 18**
Accumulated provisions:	
External trust funds, at fair value	$385
Internal reserves	31
Total	$416

All of the Company's decommissioning costs for ratemaking are based on the site study. The Company expects the Alabama PSC to periodically review and adjust, if necessary, the amounts collected in rates for the anticipated cost of decommissioning.

The Company filed an application with the NRC in September 2003 to extend the operating license for Plant Farley for an additional 20 years.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalized

In accordance with regulatory treatment, the Company records 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. Interest related to the construction of new facilities not included in the Company's regulated rates is capitalized in accordance with standard interest capitalization requirements. All current construction costs should be included in retail rates. The composite rate used to determine the amount of AFUDC was 9.0 percent in 2003, 8.2 percent in 2002, and 7.7 percent in 2001. AFUDC and interest capitalized, net of income tax, as a percent of net income after dividends on preferred stock was 3.5 percent in 2003 and 3.3 percent in each of 2002 and 2001.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and/or cost of funds used during construction.

The cost of replacements of property -- exclusive of minor items of property -- is capitalized. The cost of maintenance, repairs and replacement of minor items of property is charged to maintenance expense as incurred or performed with the exception of nuclear refueling costs, which are recorded in accordance with specific Alabama PSC orders. The Company accrues estimated refueling costs in advance of the unit's next refueling outage. The refueling cycle is 18 months for each unit. During 2003, the Company accrued $28.5 million to the nuclear refueling outage reserve and at December 31, 2003 the reserve balance was $14.0 million.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined either by the amount of the regulatory disallowance or by estimating the fair value of the assets and recording a provision for loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment provision is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

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.

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.

Natural Disaster Reserve

In accordance with an Alabama PSC order, the Company has established a Natural Disaster Reserve. The Company is allowed to accrue $250 thousand per month until the maximum accumulated provision of $32 million is attained. Higher accruals to restore the reserve to its authorized level are allowed whenever the balance in the reserve declines below $22.4 million. During 2003, the Company accrued $3 million to the reserve and at December 31, 2003, the reserve balance was $12.6 million.

Stock Options

Southern Company provides non-qualified stock options to a large segment of the Company's employees ranging from line management to executives. The Company accounts for its stock-based compensation plans in accordance with Accounting Principles Board Opinion No. 25.

Accordingly, no compensation expense has been recognized because the exercise price of all options granted equaled the fair-market value on the date of grant. When options are exercised, the Company receives a capital contribution from Southern Company equivalent to the related income tax benefit.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities and are measured at fair value. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are exempt from fair value accounting requirements and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions. This results in the deferral of related gains and losses in other comprehensive income or regulatory assets or liabilities as appropriate until the hedged transactions occur. Any ineffectiveness is recognized currently in net income. Other derivative contracts are marked to market through current period income and are recorded on a net basis in the Statements of Income.

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

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

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
At December 31, 2003	**$3,903**	**$3,958**
At December 31, 2002	3,991	4,065
Preferred Securities:		
At December 31, 2003	**300**	**305**
At December 31, 2002	300	303

The fair value for long-term debt and preferred securities was based on either closing market prices or closing prices of comparable instruments.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income and changes in the fair value of qualifying cash flow hedges and changes in additional minimum pension liabilities, less income taxes and reclassifications for amounts included in net income.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. The plan is funded in accordance with Employee Retirement Income Security Act (ERISA) requirements. The Company also provides certain non-qualified benefit plans for a selected group of management and highly-compensated employees. Benefits under these non-qualified plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees. The Company funds trusts to the extent required by the Alabama PSC. For the year ended December 31, 2004, postretirement benefit contributions are expected to total approximately $4.2 million.

The measurement date for plan assets and obligations is September 30 for each year. In 2002, the Company adopted several plan changes that had the effect of increasing benefits to both current and future retirees.

Pension Plans

The accumulated benefit obligation for the pension plans was $1.20 billion in 2003 and $1.09 billion in 2002. Changes during the year in the projected benefit obligations, accumulated benefit obligations, and fair value of plan assets were as follows:

	Projected Benefit Obligations	
	2003	2002
	(in millions)	
Balance at beginning of year	**$1,088**	$1,011
Service cost	**27**	26
Interest cost	**68**	74
Benefits paid	**(61)**	(61)
Plan amendments	**3**	22
Actuarial (gain) loss	**75**	16
Balance at end of year	**$1,200**	$1,088

	Plan Assets	
	2003	2002
	(in millions)	
Balance at beginning of year	**$1,419**	$1,584
Actual return on plan assets	**226**	(106)
Benefits paid	**(62)**	(59)
Balance at end of year	**$1,583**	$1,419

Pension plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the IRS revenue code. The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity, as described in the table below. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes. The Company primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk.

	Plan Assets		
	Target	**2003**	2002
Domestic equity	37%	**37%**	35%
International equity	20	**20**	18
Global fixed income	26	**24**	25
Real estate	10	**11**	12
Private equity	7	**8**	10
Total	100%	**100%**	100%

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

	2003	2002
	(in millions)	
Funded status	**$383**	$331
Unrecognized transition amount	**(5)**	(10)
Unrecognized prior service cost	**87**	93
Unrecognized net (gain) loss	**(37)**	(40)
Prepaid pension asset, net	**428**	374
Portion included in benefit obligations	**18**	16
Total prepaid assets recognized in the Balance Sheets	**$446**	$390

In 2003 and 2002, amounts recognized in the Balance Sheets for accumulated other comprehensive income and intangible assets to record the minimum pension liability related to the non-qualified plans were $12.8 million and $6.7 million and $6.7 and $4.8 million, respectively.

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

	2003	2002	2001
	(in millions)		
Service cost	**$ 27**	$ 26	$ 25
Interest cost	**68**	74	70
Expected return on plan assets	**(138)**	(138)	(131)
Recognized net gain	**(12)**	(20)	(22)
Net amortization	**3**	2	1
Net pension cost (income)	**$ (52)**	$ (56)	$ (57)

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	
	2003	2002
	(in millions)	
Balance at beginning of year	**$405**	$348
Service cost	**6**	5
Interest cost	**26**	26
Benefits paid	**(20)**	(20)
Actuarial (gain) loss	**24**	46
Balance at end of year	**$441**	$405

	Plan Assets	
	2003	2002
	(in millions)	
Balance at beginning of year	**$158**	$169
Actual return on plan assets	**25**	(12)
Employer contributions	**23**	21
Benefits paid	**(20)**	(20)
Balance at end of year	**$186**	$158

Postretirement benefits plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the IRS revenue code. The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity, as described in the table below. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes. The Company primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk.

	Plan Assets		
	Target	**2003**	2002
Domestic equity	46%	**50%**	42%
International equity	13	**14**	9
Global fixed income	34	**28**	40
Real estate	4	**5**	5
Private equity	3	**3**	4
Total	100%	**100%**	100%

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

	2003	2002
	(in millions)	
Funded status	**$(255)**	$(247)
Unrecognized transition obligation	**37**	41
Unrecognized prior service cost	**73**	77
Unrecognized net loss (gain)	**82**	66
Fourth quarter contributions	**6**	8
Accrued liability recognized in the Balance Sheets	**$ (57)**	$ (55)

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

	2003	2002	2001
	(in millions)		
Service cost	**$ 6**	$ 5	$ 5
Interest cost	**25**	25	24
Expected return on plan assets	**(17)**	(16)	(15)
Net amortization	**9**	9	7
Net postretirement cost	**$ 23**	$ 23	$ 21

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations and the net periodic costs for the pension and postretirement benefit plans were as follows:

	2003	2002	2001
Discount	**6.00%**	6.50%	7.50%
Annual salary increase	**3.75**	4.00	5.00
Long-term return on plan assets	**8.50**	8.50	8.50

The Company determined the long-term rate of return on historical asset class returns and current market conditions, taking into account the diversification benefits of investing in multiple asset classes.

An additional assumption used in measuring the accumulated postretirement benefit obligations was a weighted average medical care cost trend rate of 8.25 percent for 2003, decreasing gradually to 5.25 percent through the year 2010, and remaining at that level thereafter. An annual increase or decrease in the assumed medical care cost trend rate of 1 percent would affect the accumulated benefit obligation and the service and interest cost components at December 31, 2003 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	**$34**	**$30**
Service and interest costs	**2**	**2**

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 were $12 million for each of the years 2003, 2002, and 2001.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, and citizen enforcement of environmental requirements, has increased generally throughout the United States. In particular, personal injury claims for damages caused by alleged exposure to hazardous materials have become more frequent. The ultimate outcome of such litigation against the Company cannot be predicted at this time; however, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on the Company's financial statements.

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against the Company. The complaint alleged violations of the New Source Review (NSR) provisions of the Clean Air Act and violations of related state laws with respect to coal-fired generating facilities at the Company's Plants Miller, Barry, and Gorgas. The civil action requested penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. The EPA concurrently issued to the Company a notice of violation relating to these specific facilities, as well as Plants Greene County and Gaston. In early 2000, the EPA filed a motion to amend its complaint to add the violations alleged in its notice of violation.

In August 2000, the U.S. District Court in Georgia granted the Company's motion to dismiss for lack of jurisdiction in Georgia. The EPA refiled its claim against the Company in the U.S. District Court for the Northern

District of Alabama. The EPA brought similar NSR enforcement actions against several other electric utility companies across the country including Georgia Power and Savannah Electric. In each case, the EPA alleged that the utilities failed to comply with the NSR permitting requirements when performing maintenance and construction activities at coal-burning plants, which activities the utilities considered to be routine or otherwise not subject to NSR.

The action against the Company was stayed in the spring of 2001 during the appeal of a very similar NSR enforcement action against the Tennessee Valley Authority (TVA) before the U.S. Court of Appeals for the Eleventh Circuit. The TVA appeal involves many of the same legal issues raised by the actions against the Company. Because the final resolution of the TVA appeal could have a significant impact on the Company, it has been involved in that appeal. On June 24, 2003, the court of appeals issued its ruling in the TVA case. It found unconstitutional the statutory scheme set forth in the Clean Air Act that allowed the EPA to impose penalties for failing to comply with an administrative compliance order, like the one issued to TVA, without the EPA having to prove the underlying violation. Thus, the court of appeals held that the compliance order was of no legal consequence, and TVA was free to ignore it. The court did not, however, rule directly on the substantive legal issues about the proper interpretation and application of certain NSR provisions that had been raised in the TVA appeal. On September 16, 2003, the court of appeals denied the EPA's request for a rehearing of the decision. On February 13, 2004, the EPA petitioned the U.S. Supreme Court to review the decision of the court of appeals. The EPA also filed a motion to lift the stay in the action against the Company.

Since the inception of the NSR proceedings against the Company, the EPA has also been proceeding with similar NSR enforcement actions against other utilities, involving many of the same legal issues. In each case, the EPA alleged that the utilities failed to comply with the NSR permitting requirements when performing maintenance and construction activities at coal-burning plants, which activities the utilities considered to be routine or otherwise not subject to NSR. In 2003, district courts addressing these cases have issued opinions that reached conflicting conclusions.

In October 2003, the EPA issued final revisions to its NSR regulations under the Clean Air Act clarifying the scope of the existing Routine Maintenance, Repair, and Replacement exclusion. On December 24, 2003, the U.S. Court of Appeals for the District of Columbia Circuit stayed the effectiveness of these revisions pending resolution of related litigation over those revisions. In January 2004, the Bush Administration announced that it would continue to enforce the existing rules.

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 in this matter could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

Open Access Transmission Tariff

In October 2003, the FERC approved a new Open Access Transmission Tariff for the Company of $1.73 per kilowatt-month based on an 11.25 percent return on equity. The Company had requested a rate increase effective April 2002 based on a 13 percent return on equity. In September 2002, pending FERC approval, the Company began collecting from customers based on the 13 percent rate, but recorded revenue subject to refund for amounts above the previously approved rate of $1.37 per kilowatt-month. As a result of the final settlement, a total of approximately $2.4 million was refunded to the Company's transmission customers in October 2003 and $7.6 million was recorded as revenue.

Retail Rate Adjustment Procedures

The Alabama PSC has adopted rates that provide for periodic adjustments based upon the Company's earned return on end-of-period retail common equity. Increases in retail rates of 2 percent were effective in April 2002 and in October 2001 in accordance with the Rate Stabilization Equalization Plan, amounting to an annual increase of $55 million and $58 million, respectively. In March 2002, the Alabama PSC approved a revision to the rate adjustment procedures that provides for an annual, rather than quarterly, adjustment and imposes a 3 percent limit on changes in rates in any calendar year. The return on common equity range of 13.0 percent to 14.5 percent remained unchanged.

The rates also provide for adjustments to recognize the placing of new generating facilities into retail service and the recovery of retail costs associated with certificated purchased power agreements (PPAs) under Rate CNP (Certificated New Plant). Effective July 2001, the Company's retail rates were adjusted by 0.6 percent ($17 million annually) under Rate CNP to recover costs for Plant Barry Unit 7, which was placed into commercial operation on May 1, 2001.

In November 2000, the Alabama PSC certificated a seven-year, 615 megawatt, PPA with Southern Power beginning in June 2003. In addition, the Alabama PSC certificated a seven-year PPA with a third party for approximately 630 megawatts; one half of the capacity became available in 2003 while the remaining half is scheduled to become available in 2004. As a result, the Company's retail rates were adjusted beginning July 2003 by approximately 2.6 percent ($79 million annually) under Rate CNP. One month after the contracted capacity delivery begins, which is scheduled for June 2004, Rate CNP will adjust retail rates by approximately 0.8 percent ($25 million annually) to recover costs associated with the scheduled 2004 PPA capacity.

In October 2001, the Alabama PSC approved a revision to the Company's Rate ECR (Energy Cost Recovery) allowing the recovery of specific costs associated with the sales of natural gas that become necessary due to operating considerations at its electric generating facilities. This revision also includes the cost of financial tools used for hedging market price risk up to 75 percent of the budgeted annual amount of natural gas purchases. The Company may not engage in natural gas hedging activities that extend beyond a rolling 42-month window. Also, the premiums paid for natural gas financial options may not exceed 5 percent of the Company's natural gas budget for that year.

The Company's ratemaking procedures will remain in effect until the Alabama PSC votes to modify or discontinue them.

FERC Matters

The Company has obtained FERC approval to sell power to nonaffiliates at market-based prices under specific contracts. Through SCS, as agent, the Company also has FERC authority to make short-term opportunity sales at market rates. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate. In November 2001, the FERC modified the test it uses to consider utilities' applications to charge market-based rates and adopted a new test called the Supply Margin Assessment (SMA). The FERC applied the SMA to several utilities, including Southern Company's retail operating companies, and found them to be "pivotal suppliers" in their service areas and ordered the implementation of several mitigation measures. SCS, on behalf of the retail operating companies, sought rehearing of the FERC order, and the FERC delayed the implementation of certain mitigation measures. SCS, on behalf of the retail operating companies, submitted comments to the FERC in 2002 regarding these issues. In December 2003, the FERC issued a staff paper discussing alternatives and held a technical conference in January 2004. The Company anticipates that the FERC will address the requests for rehearing in the near future. Regardless of the outcome of the SMA proposal, the FERC retains the ability to modify or withdraw the authorization for any seller to sell at market-based rates, if it determines that the underlying conditions for having such authority are no longer applicable. The final outcome of this matter will depend on the form in which the SMA test and mitigation measures rules may be ultimately adopted and cannot be determined at this time.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Georgia Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 megawatts, together with associated transmission facilities. The capacity of these units is sold equally to the Company and Georgia Power under a contract which, in substance, requires payments sufficient to provide for the operating expenses, taxes, interest expense and a return on equity, 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 purchased power totaled $87 million in 2003, $84 million in 2002, and $80 million in 2001 and is included in "Purchased power from affiliates" in the Statements of Income.

In addition the Company has guaranteed unconditionally the obligation of SEGCO under an installment sale agreement for the purchase of certain pollution control facilities at SEGCO's generating units, pursuant to which $24.5 million principal amount of pollution control revenue bonds are outstanding. Georgia Power has agreed to reimburse the Company for the pro rata portion of such obligation corresponding to its then proportionate ownership of stock of SEGCO if the Company is called upon to make such payment under its guaranty.

At December 31, 2003, the capitalization of SEGCO consisted of $63 million of equity and $94 million of debt on which the annual interest requirement is $3.4 million. SEGCO paid dividends totaling $2.3 million in 2003, $5.8 million in 2002, and $0.7 million in 2001, of which one-half of each was paid to the Company. In addition, the Company recognizes 50 percent of SEGCO's net income.

In addition to the Company's ownership of SEGCO, the Company's percentage ownership and investment in jointly-owned generating plants at December 31, 2003 is as follows:

Facility (Type)	Total Megawatt Capacity	Company Ownership
Greene County (coal)	**500**	**60.00%** (1)
Plant Miller Units 1 and 2 (coal)	**1,320**	**91.84%** (2)

(1) Jointly owned with an affiliate, Mississippi Power.
(2) Jointly owned with Alabama Electric Cooperative, Inc.

Facility	Company Investment	Accumulated Depreciation
	(in millions)	
Greene County	**$110**	**$ 54**
Plant Miller Units 1 and 2	**767**	**355**

The Company has contracted to operate and maintain the jointly owned facilities as agent for their co-owners. The Company's proportionate share of its plant operating expenses is included in the operating expenses in the Statements of Income.

5. INCOME TAXES

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

At December 31, 2003, the Company's tax-related regulatory assets and liabilities were $321 million and $162 million, respectively. These assets are attributable to tax benefits flowed through to customers in prior years and to taxes applicable to capitalized interest. These liabilities are attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized investment tax credits.

Details of the income tax provisions are as follows:

	2003	2002	2001
	(in millions)		
Total provision for income taxes:			
Federal --			
Current	**$111**	$209	$234
Deferred	**137**	41	(20)
	248	250	214
State --			
Current	**26**	35	37
Deferred	**16**	7	(2)
	42	42	35
Total	**$290**	$292	$249

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:

	2003	2002
	(in millions)	
Deferred tax liabilities:		
Accelerated depreciation	**$1,204**	$1,081
Property basis differences	**401**	381
Premium on reacquired debt	**42**	39
Pensions	**117**	103
Other	**29**	38
Total	**1,793**	1,642
Deferred tax assets:		
Capacity prepayments	**8**	11
Other deferred costs	**13**	13
Postretirement benefits	**14**	18
Unbilled revenue	**21**	20
Other	**86**	87
Total	**142**	149
Total deferred tax liabilities, net	**1,651**	1,493
Portion included in current liabilities, net	**(80)**	(56)
Accumulated deferred income taxes in the Balance Sheets	**$1,571**	$1,437

In accordance with regulatory requirements, deferred investment tax credits are amortized over the lives 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 $11 million in each of 2003, 2002, and 2001. At December 31, 2003, all investment tax credits available to reduce federal income taxes payable had been utilized.

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

	2003	2002	2001
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**3.5**	3.5	3.5
Non-deductible book depreciation	**1.2**	1.3	1.5
Differences in prior years' deferred and current tax rates	**(0.9)**	(1.2)	(1.3)
Other	**(1.6)**	(0.5)	(0.5)
Effective income tax rate	**37.2%**	38.1%	38.2%

6. FINANCING

Mandatorily Redeemable Preferred Securities

The Company has formed certain wholly owned trust subsidiaries for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the Company through the issuance of junior subordinated notes totaling $309 million, which constitute substantially all assets of these trusts. The Company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the respective trusts' payment obligations with respect to these securities. At December 31, 2003, preferred securities of $300 million were outstanding and recognized as liabilities in the Balance Sheets. For additional information, see the Statements of Capitalization.

First Mortgage Bonds

In October 1991, the Company entered into a firm power sales contract with the Alabama Municipal Electric Authority (AMEA) entitling AMEA to scheduled amounts of capacity (up to a maximum 80 megawatts) for a period of 15 years. Under the terms of the contract, the Company received payments from AMEA representing the net present value of the revenues associated with the capacity entitlement, discounted at an effective annual rate of 11.19 percent. These payments are being recognized as operating revenues and the discount is amortized to other interest expense as scheduled capacity is made available over the terms of the contract.

To secure AMEA's advance payments and the Company's performance obligation under the contracts, the Company issued and delivered to an escrow agent first mortgage bonds representing the maximum amount of liquidated damages payable by the Company in the event of a default under the contracts. No principal or interest is payable on such bonds unless and until a default by the Company occurs. As the liquidated damages decline, a portion of the bond equal to the decrease is returned to the Company. At December 31, 2003, $26.7 million of these bonds were held by the escrow agent under the contract.

Pollution Control Bonds

Pollution control obligations represent installment purchases of pollution control facilities financed by funds derived from sales by public authorities of revenue bonds. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. With respect to $114.2 million of such pollution control obligations, the Company has authenticated and delivered to the trustees a like principal amount of first mortgage bonds as security for its obligations under the installment purchase agreements. No principal or interest on these first mortgage bonds is payable unless and until a default occurs on the installment purchase agreements.

Senior Notes

The Company issued a total of $1.4 billion of unsecured senior notes in 2003. The proceeds of these issues were used to redeem higher cost debt and for other general corporate purposes.

At December 31, 2003 and 2002, the Company had $3.4 billion of senior notes outstanding. These senior notes are subordinate to all secured debt of the Company which amounted to approximately $295 million at December 31, 2003.

Long-Term Debt Due Within One Year

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

	2003	2002
	(in millions)	
Capitalized leases	**$ 1**	$ 1
Senior notes	**525**	1,117
Total	**$526**	$1,118

Debt redemptions and/or serial maturities through 2008 applicable to total long-term debt are as follows: $526 million in 2004; $225 million in 2005; $715 million in 2006; $200 million in 2007; and $410 million in 2008.

Assets Subject to Lien

The Company's mortgage, 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.

Bank Credit Arrangements

The Company maintains committed lines of credit in the amount of $865 million (including $504 million of such lines which are dedicated to funding purchase obligations relating to variable rate pollution control bonds), all of which expire at various times during 2004. Approximately $450 million of the credit facilities expiring in 2004 allow for the execution of term loans for an additional two-year period, and $245 million allow for the execution of one-year term loans. All of the credit arrangements require payment of a commitment fee based on the unused portion of the commitment or the maintenance of compensating balances with the banks. Commitment fees are less than 1/4 of 1 percent for the Company. Because the arrangements are based on an average balance, the Company does not consider any of its cash balances to be restricted as of any specific date. For syndicated credit arrangements, a fee is also paid to the agent bank.

Most of the Company's credit arrangements with banks have covenants that limit the Company's debt to 65 percent of total capitalization, as defined in the agreements. Exceeding this debt level would result in a default under the credit arrangements. At December 31, 2003, the Company was in compliance with the debt limit covenants. In addition, the credit arrangements typically contain cross default provisions that would be triggered if the Company defaulted on other indebtedness (including guarantee obligations) above a specified threshold. None of the arrangements contain material adverse change clauses at the time of borrowings.

The Company borrows through commercial paper programs that have the liquidity support of committed bank credit arrangements. In addition, the Company borrows from time to time through extendible commercial note programs. As of December 31, 2003, the Company had no extendible commercial notes and no commercial paper outstanding. The amount of commercial paper outstanding at December 31, 2002 was $37 million. During 2003, the peak amount outstanding for commercial paper was $255 million and the average amount outstanding was $30 million. The average annual interest rate on commercial paper in 2003 was 1.29 percent. Commercial paper and extendible commercial notes are included in notes payable on the Balance Sheets.

At December 31, 2003, the Company had regulatory approval to have outstanding up to $1 billion of short-term borrowings.

Financial Instruments

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company has implemented fuel-hedging programs at the instruction of the Alabama PSC. The Company also enters into hedges of forward electricity sales.

At December 31, 2003, the fair value of derivative energy contracts was reflected in the financial statements as follows:

	Amounts (in thousands)
Regulatory liabilities, net	$6,402
Net income	11
Total fair value	$6,413

The fair value gain or loss for cash flow hedges that are recoverable through the regulatory fuel clauses are recorded in the regulatory assets and liabilities and are recognized in earnings at the same time the hedged items affect earnings.

The Company also enters into derivatives to hedge exposure of interest rate changes. Interest derivatives related to variable rate securities or forecasted transactions are accounted for as cash flow hedges. The interest derivatives are generally structured to match the critical terms of the hedged debt instruments; therefore, no material ineffectiveness has been recorded in earnings.

At December 31, 2003, the Company had $1.2 billion notional amount of interest rate swaps outstanding with net deferred gains of $5.7 million as follows:

Cash Flow Hedges

Maturity	Weighted Average Fixed Rate Paid	Notional Amount	Fair Value Gain/(Loss)
		(in millions)	
2004	1.63*	$486	$(0.2)
2006	1.89	195	1.5
2007	1.99*	486	4.4

*Hedged using the Bond Market Association Municipal Swap Index.

The fair value gain or loss for cash flow hedges is recorded in other comprehensive income and is reclassified into earnings at the same time the hedged items affect earnings. In 2003 and 2002, the Company recognized losses of $8 million and $13 million, respectively, upon termination of certain interest derivatives at the same time it issued debt. These losses have been deferred in other comprehensive income and will be amortized to interest expense over the life of the related debt. For 2003, approximately $11.3 million of pre-tax losses were reclassified from other comprehensive income to interest expense. For 2004, pre-tax losses of approximately $5.8 million are expected to be reclassified from other comprehensive income to interest expense.

7. COMMITMENTS

Construction Program

The Company is engaged in continuous construction programs, currently estimated to total $791 million in 2004, $863 million in 2005, and $884 million in 2006. These amounts include $12.5 million, $11.3 million, and $6.6 million in 2004, 2005, and 2006, respectively, for construction expenditures related to contractual purchase commitments for uranium and nuclear fuel conversion, enrichment, and fabrication services included in this note under "Fuel Commitments." The construction programs are subject to periodic review and revision, and actual construction costs may vary from the above estimates because of numerous factors. These factors include: changes in business conditions; revised load growth estimates; changes in environmental regulations; changes in existing nuclear plants to meet new regulatory requirements; changes in FERC rules and transmission regulations; increasing costs of labor, equipment, and materials; and cost of capital. At December 31, 2003, significant purchase commitments were outstanding in connection with the construction program. The Company has no generating plants under construction. Construction of new transmission and distribution facilities and capital improvements, including those needed to meet environmental standards for existing generation transmission, and distribution facilities, will continue.

Southern Company has guaranteed Southern Power's obligations to the Company for transmission interconnection facilities of $6.8 million related to Plant Harris units 1 & 2. The obligations were guaranteed at December 31, 2003, but, upon completion of construction, were released in February 2004.

Long-Term Service Agreements

The Company has entered into several Long-Term Service Agreements (LTSAs) with General Electric (GE) for the purpose of securing maintenance support for its combined cycle and combustion turbine generating facilities. The LTSAs stipulate that GE will perform all planned maintenance on the covered equipment, which includes the cost of all labor and materials. GE is also obligated to cover the costs of unplanned maintenance on the covered equipment subject to a limit specified in each contract.

In general, these LTSAs are in effect through two major inspection cycles per unit. Scheduled payments to GE are made at various intervals based on actual operating hours of the respective units. Total payments to GE under these agreements are currently estimated at $253 million over the life of the agreements, which are approximately 12 to 14 years per unit. At December 31, 2003, the remaining balance was approximately $213 million. However, the LTSAs contain various cancellation provisions at the option of the Company.

Payments made to GE prior to the performance of any planned maintenance are recorded as a prepayment in the Balance Sheets. Inspection costs are capitalized or charged to expense based on the nature of the work performed.

Purchased Power Commitments

The Company has entered into various long-term commitments for the purchase of electricity. Total estimated minimum long-term obligations at December 31, 2003 were as follows:

	Commitments		
Year	Affiliated	Non-Affiliated	Total
		(in millions)	
2004	$ 49	$ 36	$ 85
2005	49	38	87
2006	49	39	88
2007	49	40	89
2008	49	40	89
2009 and thereafter	62	67	129
Total commitments	$307	$260	$567

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. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery. Amounts included in the chart below represent estimates based on New York Mercantile future prices at December 31, 2003. Total estimated minimum long-term commitments at December 31, 2003 were as follows:

Year	Natural Gas	Coal & Nuclear Fuel
	(in millions)	
2004	$318	$ 750
2005	181	514
2006	158	437
2007	107	429
2008	26	154
2009 and thereafter	108	-
Total commitments	$898	$2,284

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

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other Southern Company retail operating companies, Southern Power, and Southern Company GAS. Under these agreements, each of the retail operating companies, Southern Power, and Southern Company GAS may be jointly and severally liable. The creditworthiness of Southern Power and Southern Company GAS is currently inferior to the creditworthiness of the retail operating companies. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other retail operating companies to insure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power or Southern Company GAS as a contracting party under these agreements.

Operating Leases

The Company has entered into rental agreements for coal rail cars, vehicles, and other equipment with various terms and expiration dates. These expenses totaled $29.5 million in 2003, $29.6 million in 2002, and $27.9 million in 2001. Of these amounts, $19.4 million, $19.1 million, and $21.1 million for 2003, 2002, and 2001, respectively, relates to the rail car leases and are recoverable through the Company's energy cost recovery clause. At December 31, 2003, estimated minimum rental commitments for noncancellable operating leases were as follows:

Year	Rail Cars	Vehicles & Other	Total
		(in millions)	
2004	$19.1	$10.6	$ 29.7
2005	16.3	8.9	25.2
2006	11.3	6.2	17.5
2007	4.1	3.6	7.7
2008	3.8	2.0	5.8
2009 and thereafter	30.7	4.5	35.2
Total minimum payments	$85.3	$35.8	$121.1

In addition to the rental commitments above, the Company has potential obligations upon expiration of certain leases with respect to the residual value of the leased property. These leases expire in 2004 and 2006, and the Company's maximum obligations are $25.7 million and $66.0 million, respectively. At the termination of the leases, at the Company's option, the Company may negotiate an extension, exercise its purchase option, or the property can be sold to a third party. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligations.

Guarantees

At December 31, 2003, the Company had outstanding guarantees related to SEGCO's purchase of certain pollution control facilities, as discussed in Note 4, and to certain residual values of leased assets. See "Operating Leases" above.

8. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act of 1988 (Act), 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 Plant Farley. The Act provides funds up to $10.9 billion for public liability claims that could arise from a single nuclear incident. Plant Farley is insured against this liability to a maximum of $300 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of nuclear reactors. The Company could be assessed up to $100.5 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, excluding any applicable state premium taxes, for the Company is $201 million per incident but not more than an aggregate of $20 million to be paid for each incident in any one year. The Price-Anderson Amendments Act expired in August 2002; however, the indemnity provisions of the act remain in place for commercial nuclear reactors.

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

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

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After this deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. The Company purchases the maximum limit allowed by NEIL and has elected a 12 week waiting period.

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 NEIL policies would be $36 million.

Following the terrorist attacks of September 2001, both ANI and NEIL confirmed that terrorist acts against commercial nuclear power plants would be covered under their insurance. However, both companies revised their policy terms on a prospective basis to include an industry aggregate for all "non-certified" terrorist acts, i.e., acts that are not certified acts of terrorism pursuant to the Terrorism Risk Insurance Act of 2002 (TRIA). The NEIL aggregate -- applies to all non-certified claims stemming from terrorism within a 12 month duration -- is $3.24 billion plus any amounts available through reinsurance or indemnity from an outside source. The non-certified ANI cap is a $300 million shared industry aggregate. Any act of terrorism that is certified pursuant to the TRIA will not be subject to the foregoing NEIL and ANI limitations but will be subject to the TRIA annual aggregate limitation of $100 billion of insured losses arising from certified acts of terrorism. The TRIA will expire on December 31, 2005.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall 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.

9. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2003 and 2002 are as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred Stock
		(in millions)	
March 2003	**$ 890**	**$211**	**$ 92**
June 2003	**950**	**227**	**107**
September 2003	**1,216**	**414**	**217**
December 2003	**904**	**163**	**57**
March 2002	$ 802	$191	$ 72
June 2002	924	256	116
September 2002	1,119	393	201
December 2002	865	182	72

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

SELECTED FINANCIAL AND OPERATING DATA 1999-2003

	2003	2002	2001	2000	1999
Operating Revenues (in thousands)	**$3,960,161**	$3,710,533	$3,586,390	$3,667,461	$3,385,474
Net Income after Dividends on Preferred Stock (in thousands)	**$472,810**	$461,355	$386,729	$419,916	$399,880
Cash Dividends on Common Stock (in thousands)	**$430,200**	$431,000	$393,900	$417,100	$399,600
Return on Average Common Equity (percent)	**13.75**	13.80	11.89	13.58	13.85
Total Assets (in thousands)	**$12,070,624**	$11,591,666	$11,303,605	$11,228,118	$10,450,052
Gross Property Additions (in thousands)	**$648,560**	$634,094	$635,540	$870,581	$809,044
Capitalization (in thousands):					
Common stock equity	**$3,500,660**	$3,377,740	$3,310,877	$3,195,772	$2,988,863
Preferred stock	**372,512**	247,512	317,512	317,512	317,512
Mandatorily redeemable preferred securities	**300,000**	300,000	347,000	347,000	347,000
Long-term debt	**3,377,148**	2,872,609	3,742,346	3,425,527	3,190,378
Total (excluding amounts due within one year)	**$7,550,320**	$6,797,861	$7,717,735	$7,285,811	$6,843,753
Capitalization Ratios (percent):					
Common stock equity	**46.4**	49.7	42.9	43.9	43.7
Preferred stock	**4.9**	3.6	4.1	4.4	4.6
Mandatorily redeemable preferred securities	**4.0**	4.4	4.5	4.8	5.1
Long-term debt	**44.7**	42.3	48.5	46.9	46.6
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Security Ratings:					
First Mortgage Bonds -					
Moody's	**A1**	A1	A1	A1	A1
Standard and Poor's	**A**	A	A	A	A+
Fitch	**A+**	A+	A+	AA-	AA-
Preferred Stock -					
Moody's	**Baa1**	Baa1	Baa1	a2	a2
Standard and Poor's	**BBB+**	BBB+	BBB+	BBB+	A-
Fitch	**A-**	A-	A-	A	A
Unsecured Long-Term Debt -					
Moody's	**A2**	A2	A2	A2	A2
Standard and Poor's	**A**	A	A	A	A
Fitch	**A**	A	A	A+	A+
Customers (year-end):					
Residential	**1,160,129**	1,148,645	1,139,542	1,132,410	1,120,574
Commercial	**204,561**	203,017	196,617	193,106	188,368
Industrial	**5,032**	4,874	4,728	4,819	4,897
Other	**757**	789	751	745	735
Total	**1,370,479**	1,357,325	1,341,638	1,331,080	1,314,574
Employees (year-end):	**6,730**	6,715	6,706	6,871	6,792

SELECTED FINANCIAL AND OPERATING DATA 1999-2003 (continued)
Alabama Power Company 2003 Annual Report

	2003	2002	2001	2000	1999
Operating Revenues (in thousands):					
Residential	**$1,276,800**	$1,264,431	$1,138,499	$1,222,509	$1,145,646
Commercial	**913,697**	882,669	829,760	854,695	807,098
Industrial	**844,538**	788,037	763,934	859,668	843,090
Other	**16,428**	16,080	15,480	15,835	15,283
Total retail	**3,051,463**	2,951,217	2,747,673	2,952,707	2,811,117
Sales for resale - non-affiliates	**487,456**	474,291	485,974	461,730	415,377
Sales for resale - affiliates	**277,287**	188,163	245,189	166,219	92,439
Total revenues from sales of electricity	**3,816,206**	3,613,671	3,478,836	3,580,656	3,318,933
Other revenues	**143,955**	96,862	107,554	86,805	66,541
Total	**$3,960,161**	$3,710,533	$3,586,390	$3,667,461	$3,385,474
Kilowatt-Hour Sales (in thousands):					
Residential	**16,959,566**	17,402,645	15,880,971	16,771,821	15,699,081
Commercial	**13,451,757**	13,362,631	12,798,711	12,988,728	12,314,085
Industrial	**21,593,519**	21,102,568	20,460,022	22,101,407	21,942,889
Other	**203,178**	205,346	198,102	205,827	201,149
Total retail	**52,208,020**	52,073,190	49,337,806	52,067,783	50,157,204
Sales for resale - non-affiliates	**17,085,376**	15,553,545	15,277,839	14,847,533	12,437,599
Sales for resale - affiliates	**9,422,301**	8,844,050	8,843,094	5,369,474	5,031,781
Total	**78,715,697**	76,470,785	73,458,739	72,284,790	67,626,584
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**7.53**	7.27	7.17	7.29	7.30
Commercial	**6.79**	6.61	6.48	6.58	6.55
Industrial	**3.91**	3.73	3.73	3.89	3.84
Total retail	**5.84**	5.67	5.57	5.67	5.60
Sales for resale	**2.88**	2.72	3.03	3.11	2.91
Total sales	**4.85**	4.73	4.74	4.95	4.91
Residential Average Annual Kilowatt-Hour Use Per Customer	**14,688**	15,198	13,981	14,875	14,097
Residential Average Annual Revenue Per Customer	**$1,105.77**	$1,104.28	$1,002.30	$1,084.26	$1,028.76
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**12,174**	12,153	12,153	12,122	11,379
Maximum Peak-Hour Demand (megawatts):					
Winter	**10,409**	9,423	9,300	9,478	8,863
Summer	**10,462**	10,910	10,241	11,019	10,739
Annual Load Factor (percent)	**64.1**	62.9	62.5	59.3	59.7
Plant Availability (percent):					
Fossil-steam	**85.9**	85.8	87.1	89.4	80.4
Nuclear	**94.7**	93.2	83.7	88.3	91.0
Source of Energy Supply (percent):					
Coal	**56.5**	55.5	56.8	63.0	64.1
Nuclear	**17.0**	17.1	15.8	16.9	17.8
Hydro	**7.0**	5.1	5.1	2.9	4.7
Gas	**7.6**	11.6	10.7	4.9	1.1
Purchased power -					
From non-affiliates	**4.1**	4.0	4.4	4.6	4.5
From affiliates	**7.8**	6.7	7.2	7.7	7.8
Total	**100.0**	100.0	100.0	100.0	100.0

DIRECTORS AND OFFICERS
Alabama Power Company 2003 Annual Report

Directors

Whit Armstrong
President, Chairman and CEO,
The Citizens Bank

David J. Cooper
President,
Cooper/T. Smith Corporation

H. Allen Franklin
Chairman, President and CEO,
Southern Company

R. Kent Henslee
Managing Partner,
Henslee, Robertson, Strawn & Knowles, L.L.C.

John D. Johns[1]
Chairman, President and CEO,
Protective Life Corporation

Carl E. Jones, Jr.
Chairman, President and CEO,
Regions Financial Corporation

Patricia M. King
President and CEO,
King Motor Company, Inc.

James K. Lowder
Chairman,
The Colonial Company

Wallace D. Malone, Jr.
Chairman and CEO,
SouthTrust Corporation

Charles D. McCrary
President and CEO,
Alabama Power Company

Mayer Mitchell [2]
President, MBI, LLC

Malcolm Portera
Chancellor, The University of Alabama System

Robert D. Powers
President, The Eufaula Agency

Andreas Renschler [3]
President, Mcc smart Gmbh

C. Dowd Ritter
Chairman, President and CEO,
AmSouth Bancorporation

James H. Sanford
Chairman, HOME Place Farms, Inc.

William F. Walker
President, Auburn University

John Cox Webb, IV
President, Webb Lumber Company, Inc.

James W. Wright
Chairman and CEO,
First Tuskegee Bank

Officers

Charles D. McCrary
President and Chief Executive Officer

William B. Hutchins, III
Executive Vice President, Chief Financial Officer and Treasurer

C. Alan Martin
Executive Vice President

Steve R. Spencer
Executive Vice President

Rodney O. Mundy
Senior Vice President and Counsel

Robert Holmes, Jr.
Senior Vice President

Robin A. Hurst
Senior Vice President

Michael L. Scott
Senior Vice President

Jerry L. Stewart
Senior Vice President

Art P. Beattie
Vice President and Comptroller

William E. Zales, Jr.
Vice President, Corporate Secretary and Assistant Treasurer

Christopher T. Bell
Vice President

Willard L. Bowers
Vice President

Larry R. Grill [4]
Vice President

Gerald L. Johnson
Vice President

Marsha S. Johnson
Vice President, Birmingham Division

William B. Johnson
Vice President

J. Bruce Jones [5]
Vice President

Bobby J. Kerley [6]
Vice President, Southeast Division

Barbara J. Knight
Vice President

Ellen N. Lindemann
Vice President

Gordon G. Martin
Vice President, Southern Division

Donald W. Reese
Vice President

R. Michael Saxon [7]
Vice President, Southeast Division

Julia H. Segars
Vice President

Julian H. Smith, Jr.
Vice President

W. Ronald Smith
Vice President, Eastern Division

Cheryl A. Thompson
Vice President, Mobile Division

Terry H. Waters
Vice President, Western Division

Robert Cole Giddens
Assistant Comptroller

E. Wayne Boston
Assistant Secretary and Assistant Treasurer

Ceila H. Shorts
Assistant Secretary

Kay I. Worley
Assistant Secretary

J. Randy DeRieux
Assistant Treasurer

All information as of December 31, 2003 except as noted below

[1] Elected 1/04
[2] Retired 4/03
[3] Resigned 4/03
[4] Elected 4/03
[5] Retired 1/04
[6] Resigned 12/03
[7] Elected 12/03

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 operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Alabama and to wholesale customers in the Southeast. The Company sells electricity to more than 1.3 million customers within its service area of approximately 45,000 square miles. In 2003, retail energy sales accounted for 66 percent of the Company's total sales of 78.7 billion kilowatt-hours.

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

Audit Committee
Prior to April 25, 2003 the Company had an Audit Committee comprised of R. Kent Henslee, James K. Lowder, and John Cox Webb, IV. On April 25, 2003, the Board amended the Company's Bylaws to remove the provision requiring the Board to have an Audit Committee. The Southern Company Audit Committee provides broad oversight of the Company's financial reporting and control functions.

Trustee, Registrar and Interest Paying Agent
All series of First Mortgage Bonds,
Senior Notes and Mandatorily Redeemable
Preferred Securities
JPMorgan Chase Bank
Institutional Trust Services
4 New York Plaza, 15th Floor
New York, NY 10004

Registrar, Transfer Agent and Dividend Paying Agent
All series of Preferred Stock and Class A Preferred Stock except for the Flexible Money Market and 5.30% Series Class A Preferred Stock
Southern Company Services, Inc.
Stockholder Services
P.O. Box 54250
Atlanta, GA 30308-0250
(800) 554-7626

The Flexible Money Market and 5.30% Series Class A Preferred Stock
The Bank of New York
101 Barclay Street
New York, NY 10286

Number of Preferred Shareholders of record at December 31, 2003, was 1,836.

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 (205) 257-3385.

Alabama Power Company
600 North 18th Street
Birmingham, AL 35291
(205) 257-1000
www.alabamapower.com

Auditors
Deloitte & Touche LLP
417 North 20th Street
Suite 1000
Birmingham, AL 35203

Legal Counsel
Balch & Bingham LLP
P.O. Box 306
Birmingham, AL 35201