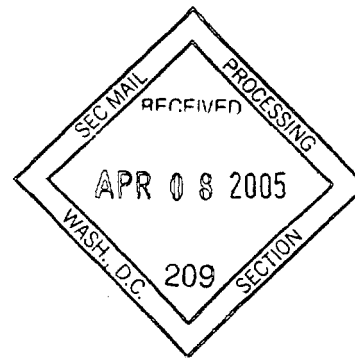


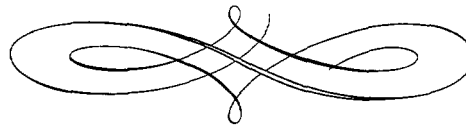
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2004 Annual Report

Alabama Power Company



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Alabama Power Company 2004 Annual Report

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SUMMARY

	2004	2003	Percent Change
Financial Highlights <i>(in millions):</i>			
Operating revenues	\$4,236	\$3,960	7.0
Operating expenses	\$3,216	\$2,945	9.2
Net income after dividends on preferred stock	\$481	\$473	1.8
Operating Data:			
Kilowatt-hour sales <i>(in millions):</i>			
Retail	54,244	52,208	3.9
Sales for resale - non-affiliates	15,483	17,086	(9.4)
Sales for resale - affiliates	7,234	9,422	(23.2)
Total	76,961	78,716	(2.2)
Customers served at year-end <i>(in thousands)</i>	1,385	1,370	1.1
Peak-hour demand <i>(in megawatts)</i>	10,938	10,462	4.5
Capitalization Ratios <i>(percent):</i>			
Common stock equity	43.8	46.4	
Preferred stock	5.6	4.9	
Mandatorily redeemable preferred securities	--	4.0	
Long-term debt payable to affiliated trusts	3.8	--	
Long-term debt	46.8	44.7	
(Excluding long-term debt due within one year)			
Return on Average Common Equity <i>(percent)</i>	13.53	13.75	

2004 Letter to Investors
Alabama Power Company 2004 Annual Report

As 2004 brought change and new challenges across the world, Alabama Power responded by focusing on the certainties of our business:

We know that our shareholders want us to provide the return we promised them.

We know our customers want reliable, affordable, environmentally friendly energy.

I am proud to report that we again met those expectations in 2004, without sacrificing the things that make Alabama Power what it is – a company of integrity, honesty and ethical behavior.

Last year, Alabama Power reclaimed the number one ranking in overall customer value, improving our scores in every customer class for the third year in a row. Our generating plants again far surpassed their goals, meeting the growing demand of our customers, and our reliability rate continued to be more than 99.9 percent. At the same time, our prices remained well below the national average.

We continued to reduce our impact on the environment, installing additional equipment and technology to reduce emissions from our generating plants. Our “Renew Our Rivers” program spread into Georgia, Mississippi and Florida, ensuring that waterways across the Southeast are cleaner.

Once again, Alabama Power met or surpassed all of its financial goals in 2004, enabling us to keep our promises to shareholders.

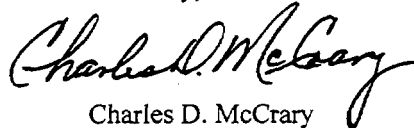
In addition to reaching our stated goals for earnings, reliability and customer service, Alabama Power also successfully responded to unexpected events. In September 2004, the worst storm in our company’s history hit the Gulf Coast of Alabama and moved northward across our service territory. Hurricane Ivan caused substantial damage and left approximately 826,000 of Alabama Power’s 1,370,000 customer accounts without electrical service. Within eight days, we restored service to 99 percent of those customers. Within two weeks, power was restored to all who could receive service.

While we’re proud of our accomplishments in 2004, we know we can’t focus on the past or solely on ourselves. Our industry is increasingly impacted by national and global issues and events, and you can be assured that Alabama Power is aware of, and prepared to meet, the challenges ahead.

At the same time, we will continue to live the philosophy that has guided Alabama Power for almost a century. As always, we will make every decision with the best interests of our customers, shareholders and employees in mind.

I have every confidence this philosophy will lead to continued success in 2005 and beyond.

Sincerely,



Charles D. McCrary
President and Chief Executive Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Alabama Power Company:

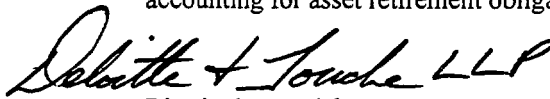
We have audited the accompanying balance sheets and statements of capitalization of Alabama Power Company (a wholly owned subsidiary of Southern Company) as of December 31, 2004 and 2003, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2004. 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.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (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 consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the

effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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 22 to 47) present fairly, in all material respects, the financial position of Alabama Power Company at December 31, 2004 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004, 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.



Birmingham, Alabama
February 28, 2005

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

Alabama Power Company 2004 Annual Report

OVERVIEW

Business Activities

Alabama Power Company (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.

Many factors affect the opportunities, challenges, and risks 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 more stringent environmental standards.

On September 15 and 16, 2004, Hurricane Ivan hit the Gulf Coast of Florida and Alabama and continued north through the state of Alabama, causing substantial damage in the service territory of the Company. Approximately 826,000 of the Company's 1,370,000 customer accounts were without electrical service immediately after the hurricane. Almost 95% of those without power had service restored within one week, and two weeks after the storm, power had been restored to all who could receive service.

In 2004, the Company completed a retail rate proceeding that should help enable the recovery of substantial capital investments associated with environmental improvements.

Key Performance Indicators

In striving to maximize shareholder value while providing low-cost energy to nearly 1.4 million customers, the Company focuses on several key indicators. These indicators include customer satisfaction, peak season equivalent forced outage rate (Peak Season EFOR), and return on equity (ROE). The Company's financial success is directly tied to the satisfaction of its customers. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses nationally recognized customer satisfaction surveys and reliability indicators to evaluate the Company's results. Peak Season EFOR is an indicator of plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated

by dividing the number of hours of forced outages by total generation hours. ROE is a performance standard used by both the investment community and many regulatory agencies. The Company's 2004 results compared with its targets for each of these indicators are reflected in the following chart.

Key Performance Indicator	2004 Target Performance	2004 Actual Performance
Customer Satisfaction	Top quartile in national and regional surveys	Top quartile
Peak Season EFOR	2.81% or less	1.86%
ROE	13.50%	13.53%

The strong financial performance achieved in 2004 reflects the focus that management places on these indicators, as well as the commitment shown by the Company's employees in achieving or exceeding management's expectations.

Earnings

The Company's 2004 net income after dividends on preferred stock was \$481 million, representing an \$8 million (1.8 percent) increase from the prior year. This improvement is due primarily to higher retail sales, increases in other revenues, and lower interest expense, partially offset by higher non-fuel operating expenses.

The 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 was due primarily to higher retail sales, 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.

The return on average common equity for 2004 was 13.53 percent compared to 13.75 percent in 2003 and 13.80 percent in 2002.

RESULTS OF OPERATIONS

A condensed income statement is as follows:

	Increase (Decrease)			
	Amount	From Prior Year		
	2004	2004	2003	2002
	(in millions)			
Operating revenues	\$4,236	\$276	\$250	\$124
Fuel	1,187	119	98	(31)
Purchased power	413	98	66	(44)
Other operation and maintenance	947	26	67	71
Depreciation and amortization	426	13	15	15
Taxes other than income taxes	243	14	11	2
Total operating expenses	3,216	270	257	13
Operating income	1,020	6	(7)	111
Total other income and (expense)	(202)	30	20	6
Income taxes	313	23	(2)	44
Net income	505	13	15	73
Dividends on preferred stock	24	5	3	(1)
Net income after dividends on preferred stock	\$ 481	\$ 8	\$ 12	\$ 74

Revenues

Operating revenues for 2004 were \$4.2 billion, reflecting a \$276 million increase from 2003. The following table summarizes the principal factors that have affected operating revenues for the past three years:

	Amount		
	2004	2003	2002
	(in millions)		
Retail -- prior year	\$3,051	\$2,951	\$2,748
Change in -			
Base rates	41	51	76
Sales growth	48	68	70
Weather	12	(61)	60
Fuel cost recovery and other	141	42	(3)
Retail -- current year	3,293	3,051	2,951
Sales for resale --			
Non-affiliates	484	488	474
Affiliates	308	277	188
Total sales for resale	792	765	662
Other operating revenues	151	144	97
Total operating revenues	\$4,236	\$3,960	\$3,710
Percent change	7.0%	6.7%	3.5%

Retail revenues in 2004 were \$3.3 billion. Revenues increased \$242 million (7.9 percent) from the prior year, increased \$100 million (3.4 percent) in 2003, and increased \$203 million (7.4 percent) in 2002. All sectors of retail revenues increased \$68 million (3.7 percent) for the Company in 2004. These 2004 and 2003 increases were primarily due to increased fuel revenue and 2.6 percent and 0.8 percent increases in retail base rates which went into effect in July 2003 and July 2004, respectively. 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 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.

Fuel rates billed to customers are designed to fully recover fluctuating fuel and purchased power costs over a period of time. At December 31, 2004, the Company had \$102 million of unrecovered fuel costs. Fuel revenues generally have no effect on net income because they represent the recording of revenues to offset fuel and purchased power 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:

	2004	2003	2002
	(in thousands)		
Unit power -			
Capacity	\$134,615	\$130,022	\$119,193
Energy	146,809	145,342	134,051
Total	\$281,424	\$275,364	\$253,244

No significant declines in the amount of capacity are scheduled until the termination of the 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 based rates that generally provide a margin above the Company's variable cost to produce

the energy. Revenues associated with other power sales to non-affiliates were as follows:

	2004	2003	2002
	(in thousands)		
Other power sales -			
Capacity and other	\$ 90,673	\$ 96,263	\$ 81,884
Variable cost of energy	111,742	115,829	139,162
Total	\$202,415	\$212,092	\$221,046

Revenues from sales to affiliated companies within the Southern Company electric system, as well as purchases of energy, will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliated sales and purchases are made in accordance with the affiliated company interchange agreements as approved by the Federal Energy Regulatory Commission (FERC). In 2004, sales for resale revenues increased \$31 million primarily due to increases in fuel-related expenses. Sales for resale revenues increased \$89.1 million in 2003 due to increased capacity payments received from affiliates. 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 2004 increased \$7.0 million (4.9 percent) from 2003 due to an increase of \$7.7 million in revenues from gas-fueled co-generation steam facilities -- primarily as a result of higher gas prices -- and a \$2.4 million increase in revenues from rent from electric property offset by a \$2.0 million decrease in transmission revenues. Since co-generation steam revenues are generally offset by fuel expense, these revenues did not have a significant impact on earnings.

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.

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.

Energy Sales

Changes in revenues are influenced heavily by the volume of energy sold each year. Kilowatt-hour (KWH) sales for 2004 and the percent change by year were as follows:

	KWH	Percent Change		
	2004	2004	2003	2002
	(millions)			
Residential	17,368	2.4%	(2.5)%	9.6%
Commercial	13,823	2.8	0.7	4.4
Industrial	22,855	5.8	2.3	3.1
Other	198	(2.4)	(1.1)	3.7
Total retail	54,244	3.9	0.3	5.5
Sales for resale -				
Non-affiliates	15,483	(9.4)	9.9	1.8
Affiliates	7,234	(23.2)	6.5	-
Total	76,961	(2.2)	2.9	4.1

Energy sales in the residential sector grew by 2.4 percent in 2004 due primarily to continued customer growth and a return to normal summer temperatures. Commercial sales increased 2.8 percent in 2004 primarily due to the State of Alabama's continuing transition from a manufacturing-based economy to a more service-based economy. Industrial sales rebounded 5.8 percent during the year with primary metal, chemical, and paper sectors leading the growth.

In 2003, residential energy sales 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.

Assuming normal weather, sales to retail customers are projected to grow approximately 1.7 percent annually on average during 2005 through 2009.

Expenses

Total operating expenses in 2004 grew \$270 million (9.2 percent) to \$3.2 billion. This increase over the previous year was primarily related to an increase in natural gas and coal prices. In addition, purchased power expenses increased \$98 million (31.0 percent) primarily due to a 71.7 percent increase in energy purchased, while purchased power prices decreased by 1.9 percent. Depreciation and amortization expense increased \$13 million (3.1 percent) primarily due to an increase in utility plant in service.

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.

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 kilowatt-hour (KWH) generated and the average cost of purchased power were as follows:

	2004	2003	2002
Total generation (billions of KWHs)	70	72	71
Sources of generation (percent) --			
Coal	65	64	62
Nuclear	19	19	19
Hydro	6	8	6
Gas	10	9	13
Average cost of fuel per net KWH generated (cents)	1.69	1.54	1.44
Average cost of purchased power per net KWH (cents)	4.79	3.61	2.91

Fuel and purchased power expenses totaled \$1.6 billion in 2004, an increase of \$216 million (15.6 percent). This was due to the average natural gas prices increasing by 30.5 percent, the average coal prices increasing 3.1 percent over the previous year, and higher capacity payments associated with an existing power purchase agreement (PPA). 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 KWHs (4.1 percent) compared with the amounts recorded in 2001.

A significant upward trend in the cost of coal and natural gas has emerged since 2003, and volatility in these markets is expected to continue. Increased coal prices have been influenced by a worldwide increase in demand as a result of rapid economic growth in China as well as by increases in mining costs. Higher natural gas prices in the United States are the result of slightly lower gas supplies despite increased drilling activity. Natural gas supply interruptions, such as those caused by the 2004 hurricanes, result in an immediate market response; however, the impact of this price volatility may be reduced by imports of natural gas and liquefied natural gas. Fuel expenses, including purchased power, are offset by fuel revenues through the Company's energy cost recovery clause and generally have no effect on net income.

Purchased power consists of purchases from affiliates in the Southern Company 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. Purchased power from non-affiliates increased \$75 million (68 percent) in 2004. This was due to a 71.7 percent increase in energy purchased offset by a 1.9 percent decrease in purchased power prices over the previous year. 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 KWHs in 2002, an 18.4 percent increase over the previous year.

Depreciation and amortization expense increased 3.1 percent in 2004, 3.6 percent in 2003, and 3.9 percent in 2002. These increases reflect additions to property, plant, and equipment.

Allowance for equity funds used during construction (AFUDC) increased \$3.5 million (28.2 percent) in 2004 due primarily to an increase in the amount of construction work in progress over the prior year. 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. See Note 1 to the financial statements under "AFUDC" for additional information.

Interest expense, net of amounts capitalized of \$194 million in 2004 decreased \$20.7 million (9.7 percent) from 2003, which had decreased \$11.4 million (5.1 percent) from 2002, which had decreased \$21 million (8.4 percent) from 2001. All years reflect a decrease in interest rates on long-term debt due to refinancing activities.

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 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 in the Company's approved electric rates.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in the State of Alabama and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Alabama PSC under cost-based regulatory principles. Prices for electricity relating to jointly owned generating facilities, interconnecting transmission lines, and the exchange of electric power are set by the FERC. Retail rates and earnings are reviewed and adjusted periodically within certain limitations based on ROE. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements for additional information about these and other regulatory matters.

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 that affect the opportunities, challenges, and risks of the Company's primary business of selling electricity. These factors include the Company's 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 more stringent environmental standards. Future earnings for the electricity business 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 of electricity, the price elasticity of demand, and the rate of economic growth in the Company's service area.

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 Southern Company Services, Inc. (SCS).

Environmental Matters

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, alleging that the Company had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws with respect to coal-fired generating facilities at the Company's Plants Miller, Barry, and Gorgas. 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. 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 was effectively stayed in the spring of 2001 pending the appeal of a similar NSR action against the Tennessee Valley Authority before the U.S. Court of Appeals for the Eleventh Circuit. In June 2004, following the final resolution of that appeal, the U.S. District Court for the Northern District of Alabama lifted the stay in the action against the Company, placing the case back onto the court's active docket. See Note 3 to the financial statements under "New Source Review Actions" for additional information.

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of \$25,000 to \$32,500 per day, per violation at each generating unit, depending on the date of the alleged violation. 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.

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 (RMRR) exclusion. A coalition of states and environmental organizations has filed petitions for review of these revisions with the U.S. Court of Appeals for the District of Columbia Circuit. The October 2003 RMRR rules have been stayed by the Court of Appeals pending its review of the rules. In any event, the final regulations must also be adopted by the State of Alabama in order to apply to the Company's facilities. The effect of these final regulations, related legal challenges, and potential state rulemakings cannot be determined at this time.

Carbon Dioxide Litigation

On July 21, 2004, attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed a complaint in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. A nearly identical complaint was filed by three environmental groups in the same court. The complaints allege that the companies' emissions of carbon dioxide, a greenhouse gas, contribute to global warming, which the plaintiffs assert is a public nuisance. Under common law public and private nuisance theories, the plaintiffs seek a judicial order (1) holding each defendant jointly and severally liable for creating, contributing to, and/or maintaining global warming and (2) requiring each of the defendants to cap its emissions of carbon dioxide and then reduce those emissions by a specified percentage each year for at least a decade. Plaintiffs have not, however, requested that damages be awarded in connection with their claims. Southern Company believes these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. Southern Company and the other defendants have filed motions to dismiss both lawsuits. Southern Company intends to vigorously defend against these claims. While the outcome of these matters cannot be determined at this time, an adverse judgment in either of these actions could result in substantial capital expenditures.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)

Alabama Power Company 2004 Annual Report

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 involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. See "FERC and Alabama PSC Matters – Environmental Rate Filing" and Note 3 to the financial statements under "Retail Rate Adjustment Procedures" for additional information. Environmental costs that are known and estimable at this time are included in capital expenditures discussed under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein. There is no assurance, however, that all such costs will, in fact, be recovered.

Compliance with the 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 and resulted in total construction expenditures of approximately \$66 million through 2000. Some of these previous 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 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 totaled approximately \$249 million through 2004.

To help 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, were required to comply with these reductions by May 31, 2004. Additional construction expenditures for

compliance with these rules are currently estimated at approximately \$369 million, of which \$169 million remains to be spent. In March 2004, the EPA redesignated the Birmingham, Alabama area from nonattainment to attainment under the one-hour ozone standard.

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 and included development of an eight-hour ozone standard, as opposed to the previous one-hour ozone standard. 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. On April 30, 2004, the EPA published its eight-hour ozone nonattainment designations and a portion of the rules implementing the new eight-hour ozone standard. The counties around Birmingham have been designated as nonattainment under the eight-hour ozone standard. Under the implementation provisions of the new rule, the EPA announced that the one-hour ozone standard will be revoked on June 15, 2005. With respect to the eight-hour nonattainment areas, state implementation plans, including new emission control regulations necessary to bring those areas into attainment, could be required as early as 2007. These state implementation plans could require reductions in nitrogen oxide emissions from power plants. The impact of the eight-hour designations and the new standard will depend on the development and implementation of Alabama's state implementation plan and therefore cannot be determined at this time.

On December 17, 2004, the EPA issued its final "nonattainment" designations for the fine particulate national ambient air quality standard. Several areas within the Company's service area were included in the EPA's final particulate matter designations. The EPA plans to propose a fine particulate matter implementation rule in 2005 and finalize the implementation rule in 2006. State implementation plans addressing the nonattainment designations may be required by 2008 and could require reductions in sulfur dioxide emissions and further reductions in nitrogen oxide emissions from power plants. The impact of the fine particulate designations will depend on the development and implementation of Alabama state implementation plans and therefore cannot be determined at this time.

In January 2004, the EPA issued a proposed Clean Air Interstate Rule (CAIR) 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 in 2005. If finalized, the rule could modify or supplant other state requirements for attainment of the fine particulate matter standard and the eight-hour ozone standard, as well as other air quality regulations. 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.

The Company has developed and maintains an environmental compliance strategy for the installation of additional control technologies and the purchase of emission allowances to assure continued compliance with current sulfur dioxide and nitrogen oxide emission regulations. Additional expenses associated with these regulations are anticipated to be incurred each year to maintain current and future compliance. Because the Company's compliance strategy is impacted by factors such as changes to existing environmental laws and regulations, increases in the cost of emissions allowances, and any change in the Company's fuel mix, future environmental compliance costs 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 and to implement emission reduction requirements that make progress toward remedying current visibility impairment in certain natural areas. 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 implementation plans in 2008 that contain emission reduction strategies for implementing BART and for achieving sufficient progress toward the Clean Air Act's visibility improvement goal. In response to litigation, the EPA proposed revised rules in May 2004, which it plans to finalize in April 2005. The impact of these regulations will depend on the promulgation of final rules and implementation of those rules by the states and, therefore, it is not possible to determine the effect of these rules on the Company at this time.

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 March 2005, and compliance could be required as early as 2008. Because the regulations have not been finalized, the impact on the Company cannot be determined at this time.

Major bills to amend the Clean Air Act to impose more stringent emissions limitations on power plants, including the Bush Administration's Clear Skies Act, have been re-proposed in 2005. The Clear Skies Act is expected to further limit power plant emissions of sulfur dioxide, nitrogen oxides, and mercury and to supplement the proposed CAIR and mercury regulatory programs. Other proposals to limit emissions of carbon dioxide have also been introduced. The cost impacts of such legislation would depend upon the specific requirements enacted and cannot be determined at this time.

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. In July 2004, the EPA published final rules that 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 and the actual limits established by the regulatory agencies.

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 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.

Global Climate Issues

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

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constraints on the emissions of greenhouse gases for a group of industrialized countries. The Bush Administration has not supported U.S. ratification of the Kyoto Protocol or other mandatory carbon dioxide reduction legislation and, in 2002, announced a goal to reduce the greenhouse gas intensity of the U.S. – the ratio of greenhouse gas emissions to the value of U.S. economic output -- by 18 percent by 2012. A year later, the Department of Energy (DOE) announced the Climate VISION program to support this goal. Energy-intensive industries, including electricity generation, are the initial focus of this program. Southern Company is leading the development of a voluntary electric utility sector climate change initiative in partnership with the government. The utility sector has pledged to reduce its greenhouse gas emissions rate by 3 to 5 percent over the next decade and, on December 13, 2004, signed a memorandum of understanding with the DOE initiating this program under Climate VISION. Because efforts under this voluntary program are just beginning, the impact of this program on the Company cannot be determined at this time.

Environmental Remediation Reserves

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 has recognized in its financial statements the costs to clean up known sites. Amounts for cleanup and ongoing monitoring costs were not material for any 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.

FERC and Alabama PSC Matters

Transmission

In December 1999, the FERC issued its final rule on Regional Transmission Organizations (RTOs). Since that time, there have been a number of additional proceedings at the FERC designed to encourage further voluntary formation of RTOs or to mandate their formation. However, at the current time, there are no active proceedings that would require the Company to participate in an RTO. Current FERC efforts that may potentially change the regulatory and/or operational structure of transmission include rules related to the standardization of generation interconnection, as well

as an inquiry into, among other things, market power by vertically integrated utilities. See "Generation Interconnection Agreements" and "Market-Based Rate Authority" herein for additional information. The final outcome of these proceedings cannot now be determined. However, the Company's financial condition, results of operations and cash flows could be adversely affected by future changes in the federal regulatory or operational structure of transmission.

Generation Interconnection Agreements

In July 2003, the FERC issued its final rule on the standardization of generation interconnection agreements and procedures (Order 2003). Order 2003 shifts much of the financial burden of new transmission investment from the generator to the transmission provider. The FERC has indicated that Order 2003, which was effective January 20, 2004, is to be applied prospectively to interconnection agreements. Subsidiaries of Tenaska, Inc., as counterparties to two previously executed interconnection agreements with the Company, have filed complaints at the FERC requesting that the FERC modify the agreements and that the Company refund a total of \$11 million previously paid for interconnection facilities, with interest. The Company has also received similar requests from other entities totaling \$2.5 million. The Company has opposed such relief, and the proceedings are still pending. The impact of Order 2003 and its subsequent rehearings on the Company and the final results of these matters cannot be determined at this time.

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to nonaffiliates at market-based prices. Through SCS, as an 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, the retail operating companies, and Southern Power, and found them and others to be "pivotal suppliers" in their retail service territories and ordered the implementation of several mitigation measures. Southern Company and others sought rehearing of the FERC order, and the FERC delayed the implementation of certain mitigation measures. In April 2004, the FERC issued an order that abandoned the SMA test and adopted a new interim analysis for measuring generation market power. This

new interim approach requires utilities to submit a pivotal supplier screen and a wholesale market share screen. If the applicant does not pass both screens, there will be a rebuttable presumption regarding generation market power. The FERC's order also sets forth procedures for rebutting these presumptions and addresses mitigation measures for those entities that are found to have market power. In the absence of specific mitigation measures, the order includes several cost-based mitigation measures that would apply by default. The FERC also initiated a new rulemaking proceeding that, among other things, will adopt a final methodology for assessing generation market power.

In July 2004, the FERC denied Southern Company's request for rehearing, along with a number of others, and reaffirmed the interim tests that it adopted in April. In August 2004, Southern Company submitted a filing to the FERC that included results showing that Southern Company passed the pivotal supplier screen for all markets and the wholesale market share screen for all markets except the Southern Company retail service territory. Southern Company also submitted other analyses to demonstrate that it lacks generation market power. On December 17, 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not at issue. As directed by this order, on February 15, 2005, Southern Company submitted additional information related to generation dominance in its retail service territory. Any new market-based rate transactions in Southern Company's retail service territory entered into after February 27, 2005 will be subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. Southern Company, along with other utilities, has also filed an appeal of the FERC's April and July 2004 orders with the U.S. Court of Appeals for the District of Columbia Circuit. The FERC has asked the court to dismiss the appeal on the grounds that it is premature.

In the event that the FERC's default mitigation measures are ultimately applied, the Company may be required to charge cost-based rates for certain wholesale sales in Southern Company's retail service territory, which may be lower than negotiated market-based rates. The final outcome of this matter will depend on the form in which the final methodology for assessing generation market power and mitigation rules may be ultimately adopted and cannot be determined at this time.

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. The final outcome of this matter cannot be determined at this time.

Nuclear Relicensing

The Company filed an application with the Nuclear Regulatory Commission (NRC) in September 2003 to extend the operating license for Plant Farley for an additional 20 years. The NRC is expected to rule on the application by July 2005. If the NRC approves the extension, the Company's annual decommissioning expense could decrease, subject to Alabama PSC approval. See Note 1 to the financial statements under "Nuclear Decommissioning" for additional information.

Environmental Rate Filing

On October 5, 2004, the Alabama PSC approved a specific rate mechanism for the recovery of the Company's retail costs associated with environmental laws, regulations, or other such mandates. The rate mechanism began operation in January 2005 and provides for the recovery of these costs pursuant to a factor that will be calculated annually. Environmental costs to be recovered include operation and maintenance expenses, depreciation and a return on invested capital. Retail rates have increased 1 percent in 2005, which should yield an annual recovery of approximately \$33 million, and are expected to increase an additional 1 percent in 2006. In conjunction with the Alabama PSC's approval, the Company agreed to a moratorium until March 2007 on any retail rate increase under the previously approved Rate Stabilization and Equalization plan (RSE). Any increase in March 2007 would be based upon the earned return on retail common equity at December 31, 2006. See Note 3 to the financial statements under "Retail Rate Adjustment Procedures" for further information on RSE.

Retail Rate Adjustments

The Company's retail rates, approved by the Alabama PSC, also provide for adjustments to recognize the placing of new generating facilities into retail service and the recovery of retail costs associated with certificated PPAs under Rate Certificated New Plant (CNP). 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. An additional increase of \$25 million annually was effective July 2004 under Rate CNP for new certificated PPAs. In April 2005, an adjustment to Rate CNP is expected to decrease retail rates by approximately 0.5 percent, or \$18.5 million annually. See Note 3 to the financial statements under "Retail Rate Adjustment Procedures" for additional information.

Retail Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Alabama PSC. In recent months, the Company has experienced higher than expected fuel costs for coal and gas. Those higher fuel costs have increased the under recovered fuel costs included in the balance sheets. In April 2005, the retail energy clause recovery factor is scheduled to increase from its current level. The Company will continue to monitor the under recovered fuel cost balance to determine if an additional adjustment to billing rates should be requested from the Alabama PSC.

Natural Disaster Cost Recovery

The Company maintains a reserve for operation and maintenance expense to cover the cost of damages from major storms to its transmission and distribution lines and the cost of uninsured damages to its generation facilities and other property. On September 15 and 16, 2004, Hurricane Ivan hit the Gulf Coast of Florida and Alabama and continued north through the state of Alabama, causing substantial damage in the service territory of the Company. Approximately 826,000 of the Company's 1,370,000 customer accounts were without electrical service immediately after the hurricane. Almost 95% of those without power had service restored within one week, and two weeks after the storm, power had been restored to all who could receive service.

The operation and maintenance expenses associated with repairing the damage to the Company's facilities and restoring service to customers as a result of Hurricane Ivan were \$57.8 million for 2004. The

balance in the Company's natural disaster reserve prior to the storm was \$14.6 million. On October 19, 2004, the Company received approval from the Alabama PSC to record its hurricane related operation and maintenance expenses in its natural disaster reserve, thereby deferring the regulatory asset for recovery in future periods. The Company is allowed to accrue \$250 thousand per month until a 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 2004, the Company accrued \$9.9 million, including an additional amount of \$6.9 million, to the reserve and at December 31, 2004 the regulatory asset totaled \$37.7 million.

In February 2005, the Company requested and received Alabama PSC approval of an accounting order that allows the Company to immediately return certain regulatory liabilities to the retail customers. The order also allows the Company to simultaneously recover from customers an accrual of approximately \$45 million to offset the costs of Hurricane Ivan and restore the natural disaster reserve. The combined effects of this order will have no impact on the Company's net income in 2005. See Notes 1 and 3 to the financial statements under "Natural Disaster Reserve" and "Natural Disaster Cost Recovery," respectively, for additional information on these reserves.

Income Tax Matters

American Jobs Creation Act of 2004

On October 22, 2004, President Bush signed the American Jobs Creation Act of 2004 (Jobs Act) into law. The Jobs Act includes a provision that allows a generation tax deduction for utilities. The Company is currently assessing the impact of the Jobs Act, including this deduction, as well as the related regulatory treatment, on its taxable income. However, the Company currently does not expect the Jobs Act to have a material impact on its financial statements.

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 \$36 million, \$52 million, and \$56 million in 2004, 2003, and 2002, respectively. Future pension income is dependent on several factors including trust earnings and changes to the pension plan. The decline in pension income is expected to continue, but should not become a pension expense in

the foreseeable future. Postretirement benefit costs for the Company were \$22 million, \$23 million, and \$23 million in 2004, 2003, and 2002, respectively, and are expected to trend upward. A portion of pension income and postretirement benefit costs is capitalized based on construction-related labor charges. Pension 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.

The Company is involved in various other 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. Southern Company senior management has discussed the development and selection of the critical accounting policies and estimates described below with 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*, which requires the financial statements to reflect the effects of rate 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 postretirement 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 legislative, 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" herein 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 additional sites that require environmental remediation or the filing of other complaints in which the Company may be asserted to be a potentially responsible party.

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- 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.

Unbilled Revenues

Revenues related to the sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated.

Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, power delivery volume, and other operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.

New Accounting Standards

On March 31, 2004, the Company prospectively adopted FASB Interpretation No. 46R, Consolidation of Variable Interest Entities, which requires the primary beneficiary of a variable interest entity to consolidate the related assets and liabilities. The adoption of FASB Interpretation No. 46R had no impact on the Company's net income. However, as a result of the adoption, the Company deconsolidated certain wholly-owned trusts established to issue preferred securities since the Company does not meet the definition of primary beneficiary established by FASB Interpretation No. 46R. See Note 1 to the financial statements under "Variable Interest Entities" for additional information.

In the third quarter 2004, the Company prospectively adopted FASB Staff Position (FSP) 106-2, Accounting and Disclosure Requirements related to the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (Medicare Act). The Medicare Act provides a 28 percent prescription drug subsidy for Medicare eligible retirees. FSP 106-2 requires recognition of the impacts of the Medicare Act in the accumulated postretirement benefit obligation (APBO) and future cost of service for postretirement medical plans. The effect of the subsidy reduced the

Company's expenses for the six months ended December 31, 2004 by approximately \$3.2 million and is expected to have a similar impact on future expenses. The subsidy's impact on the postretirement medical plan APBO was a reduction of approximately \$59.8 million. However, the ultimate impact on future periods is subject to final interpretation of the federal regulations which were published on January 21, 2005. See Note 2 to the financial statements under "Postretirement Benefits" for additional information.

FASB Statement No. 123R, Share-Based Payment was issued in December 2004. This statement requires that compensation cost relating to share-based payment transactions be recognized in financial statements. That cost will be measured based on the grant date fair value of the equity or liability instruments issued. For the Company, this statement is effective beginning on July 1, 2005. Although the compensation expense calculation required under the revised statement differs slightly, the impact on the Company's financial statements are expected to be similar to the pro forma disclosures included in Note 1 to the financial statements under "Stock Options."

See FUTURE EARNINGS POTENTIAL – "Income Tax Matters -- American Jobs Creation Act of 2004" herein for information regarding the adoption of new tax legislation. In December 2004, the FASB issued FSP 109-1, Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities provided by the American Jobs Creation Act of 2004, which requires that the generation deduction be accounted for as a special tax deduction rather than as a tax rate reduction. The Company is currently assessing the Jobs Act and this pronouncement, as well as the related regulatory treatment, but currently does not expect a material impact on the Company's financial statements.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition continued to be strong at December 31, 2004. Net cash flow from operating activities totaled \$1.0 billion, \$1.1 billion, and \$973 million for 2004, 2003, and 2002, respectively. The \$107 million decrease for 2004 in operating activities primarily relates to an increase in under recovered fuel cost and storm damage costs related to Hurricane Ivan. These increases were partially offset by the deferral of income tax liabilities arising from accelerated depreciation

deductions. Fuel costs are recoverable in future periods and are reflected on the balance sheets as under recovered regulatory clause revenues. The \$145 million increase from 2002 to 2003 resulted from the deferral of income tax liabilities arising from accelerated depreciation deductions offset by the settlement of interest rate hedges.

Significant balance sheet changes include the \$478 million increase in long-term debt for 2004 primarily due to the replacement of debt due within one year with long-term debt, and an increase of \$412 million in gross plant.

The Company's ratio of common equity to total capitalization -- including short-term debt -- was 42.6 percent in 2004, 43.3 percent in 2003, and 42.6 percent in 2002. 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, preferred stock, and preferred securities.

Security issuances are subject to regulatory approval by the Alabama PSC. Additionally, with respect to the public offering of securities, the Company must file registration statements with the Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the Alabama PSC, as well as the amounts registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

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 of 1935, as amended (PUHCA), most loans between affiliated companies must be approved in advance by the SEC.

The Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet cash needs which can fluctuate significantly due to the seasonality of the business.

To meet short-term cash needs and contingencies, the Company has various internal and external sources of liquidity. At the beginning of 2005, the Company had approximately \$84 million of cash and cash equivalents and \$868 million of unused credit arrangements with banks. 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.

The Company maintains committed lines of credit in the amount of \$868 million of which \$643 million will expire at various times during 2005. \$225 million of the credit facilities expiring in 2005 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. 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 retail operating company. The obligations of each company under these arrangements are several and there is no cross affiliate credit support.

At December 31, 2004, the Company had no commercial paper or extendible commercial notes outstanding.

Financing Activities

During 2004, the Company issued \$900 million of long-term debt and \$100 million of preferred stock. In addition, the Company issued 1 million new shares of common stock to Southern Company at \$40.00 a share and realized proceeds of \$40 million. The proceeds of these issues were used to redeem or repay at maturity long-term debt, to repay short-term indebtedness, and for other general corporate purposes.

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Composite financing rates for long-term debt, preferred stock, and preferred securities for the years 2002 through 2004, as of year-end, were as follows:

	2004	2003	2002
Long-term debt interest rate	4.14%	4.42%	5.05%
Preferred securities distribution rate	5.25	5.25	5.25
Preferred stock dividend rate	5.14	5.10	5.17

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. However, the Company is party to certain derivative agreements that could require collateral and/or accelerated payment in the event of a credit rating change to below investment grade. These agreements are primarily for natural gas price and interest rate risk management activities. At December 31, 2004, the Company's maximum potential exposure to these contracts was \$9.8 million.

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 risk management practices. Company policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, 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 January 1, 2005 was 2.57 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 \$2.5 million at January 1, 2005. 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. The Company has implemented fuel hedging programs at the instruction of the Alabama PSC.

In addition, the Company's Rate ECR allows the recovery of specific costs associated with the sales of natural gas that become necessary due to operating considerations at the Company's electric generating facilities. Rate ECR also allows recovery of 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, 2004, exposure from these activities was not material to the Company's financial position, results of operations, or cash flows. The fair value changes in energy related derivative contracts and year-end valuations were as follows at December 31:

	Changes in Fair Value	
	2004	2003
	(in thousands)	
Contracts beginning of year	\$ 6,413	\$ 21,402
Contracts realized or settled	(26,384)	(38,809)
New contracts at inception	-	-
Changes in valuation techniques	-	-
Current period changes(a)	23,988	23,820
Contracts end of year	\$ 4,017	\$ 6,413

(a) Current period changes also include the changes in fair value of new contracts entered into during the period.

	Source of 2004 Year-End Valuation Prices		
	Total	Maturity	
	Fair Value	2005	2006-2007
	(in thousands)		
Actively quoted	\$3,985	\$2,917	\$1,068
External sources	32	32	-
Models and other methods	-	-	-
Contracts end of Year	\$4,017	\$2,949	\$1,068

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, 2004, the fair value of derivative energy contracts was reflected in the financial statements as follows:

	Amounts (in thousands)
Regulatory liabilities, net	\$3,978
Other comprehensive income	-
Net income	39
Total fair value	\$4,017

Unrealized pre-tax gains (losses) on energy contracts recognized in income in 2004 and 2003 were not material. For 2002, pre-tax losses of \$2.0 million were recognized in income. 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 \$902 million for 2005, \$921 million for 2006, and \$1.0 billion for 2007. Over the next three years, the Company estimates spending \$913 million on environmental related additions (including \$276 million on selective catalytic reduction facilities), \$238 million on Plant Farley (including \$177 million for nuclear fuel), \$767 million on distribution facilities, and \$411 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 \$1.4 billion will be required by the end of 2007 for maturities of long-term debt. The Company plans to continue, when economically feasible, to retire higher cost securities 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 2004 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 "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.

The Company has 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 for other purposes and may require the Company to seek capital from other sources. For additional information, see Note 2 to the financial statements under "Postretirement Benefits."

Other funding requirements related to obligations associated with scheduled maturities of long-term debt and preferred securities, as well as the related interest, preferred stock dividends, leases, and other purchase commitments, are as follows. See Notes 1, 6, and 7 to the financial statements for additional information.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)

Alabama Power Company 2004 Annual Report

Contractual Obligations

	2005	2006- 2007	2008- 2009	After 2009	Total
	(in millions)				
Long-term debt ^(a) --					
Principal	\$ 225.0	\$1,215.0	\$ 660.0	\$2,294.4	\$ 4,394.4
Interest	185.2	327.3	243.0	1,924.7	2,680.2
Preferred stock dividends ^(b)	23.6	47.2	47.2	-	118.0
Operating leases	29.1	35.3	19.0	34.6	118.0
Purchase commitments ^(c) --					
Capital ^(d)	902.5	1,938.4	-	-	2,840.9
Coal and nuclear fuel	907.0	1,517.0	356.0	97.0	2,877.0
Natural gas ^(e)	249.0	309.0	52.0	108.0	718.0
Purchased power	87.0	175.0	179.0	38.0	479.0
Long-term service agreements	17.2	35.8	37.3	103.1	193.4
Trusts --					
Nuclear decommissioning	20.3	40.6	40.6	192.1	293.6
Postretirement benefits ^(f)	25.3	51.6	-	-	76.9
DOE assessments	4.4	4.5	-	-	8.9
Total	\$2,675.6	\$5,696.7	\$1,634.1	\$4,791.9	\$14,798.3

- (a) All amounts are reflected based on final maturity dates. The Company plans to 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, 2005, 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 \$947 million, \$921 million, and \$854 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, 2004, 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 Exchange future prices at December 31, 2004.
- (f) The Company forecasts postretirement 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 and postretirement plans, including estimated benefit payments. Certain benefit payments will be made through the related trusts. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2004 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales growth and retail rates, storm damage cost recovery, environmental regulations and expenditures, the Company's projections for postretirement benefit trust contributions, and estimated construction and other expenditures. 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 similar terminology. There are various factors that could cause actual results to differ materially from those suggested by 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;
- variations in demand for electricity and gas, including those relating to weather, the general economy and population and business growth (and declines);
- 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 the impact of pending and future rate cases and negotiations;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, 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 effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and 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;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents similar to the August 2003 power outage in the Northeast;
- 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 by the Company from time to time by the Company with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements.

STATEMENTS OF INCOME

For the Years Ended December 31, 2004, 2003, and 2002

Alabama Power Company 2004 Annual Report

	2004	2003	2002
	<i>(in thousands)</i>		
Operating Revenues:			
Retail sales	\$3,292,828	\$3,051,463	\$2,951,217
Sales for resale --			
Non-affiliates	483,839	487,456	474,291
Affiliates	308,312	277,287	188,163
Other revenues	151,012	143,955	96,862
Total operating revenues	4,235,991	3,960,161	3,710,533
Operating Expenses:			
Fuel	1,186,472	1,067,821	969,521
Purchased power --			
Non-affiliates	186,187	110,885	90,998
Affiliates	226,697	204,353	158,121
Other operations	634,030	611,418	574,979
Maintenance	313,407	309,451	279,406
Depreciation and amortization	425,906	412,919	398,428
Taxes other than income taxes	242,809	228,414	216,919
Total operating expenses	3,215,508	2,945,261	2,688,372
Operating Income	1,020,483	1,014,900	1,022,161
Other Income and (Expense):			
Allowance for equity funds used during construction	16,141	12,594	11,168
Interest income	15,677	15,220	13,991
Interest expense, net of amounts capitalized	(193,590)	(214,302)	(225,706)
Interest expense to affiliate trusts	(16,191)	-	-
Distributions on mandatorily redeemable preferred securities	-	(15,255)	(24,599)
Other income (expense), net	(24,728)	(31,702)	(28,785)
Total other income and (expense)	(202,691)	(233,445)	(253,931)
Earnings Before Income Taxes	817,792	781,455	768,230
Income taxes	313,024	290,378	292,436
Net Income	504,768	491,077	475,794
Dividends on Preferred Stock	23,597	18,267	14,439
Net Income After Dividends on Preferred Stock	\$ 481,171	\$ 472,810	\$ 461,355

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

STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2004, 2003, and 2002

Alabama Power Company 2004 Annual Report

	2004	2003	2002
	<i>(in thousands)</i>		
Operating Activities:			
Net income	\$504,768	\$ 491,077	\$ 475,794
Adjustments to reconcile net income to net cash provided from operating activities --			
Depreciation and amortization	497,010	487,370	442,660
Deferred income taxes and investment tax credits, net	252,858	153,154	48,828
Deferred revenues	(11,510)	(17,932)	(8,099)
Allowance for equity funds used during construction	(16,141)	(12,594)	(11,168)
Pension, postretirement, and other employee benefits	(29,362)	(38,953)	(34,977)
Tax benefit of stock options	10,672	8,680	6,670
Other, net	10,817	6,292	19,271
Changes in certain current assets and liabilities --			
Receivables, net	(144,256)	(13,488)	33,074
Fossil fuel stock	30,130	(13,251)	25,535
Materials and supplies	(26,229)	(4,651)	3,728
Other current assets	19,131	(953)	1,479
Accounts payable	(12,778)	77,128	(1,034)
Accrued taxes	(24,568)	(33,507)	(40,922)
Accrued compensation	(7,041)	664	17,122
Other current liabilities	(42,544)	29,058	(4,798)
Net cash provided from operating activities	1,010,957	1,118,094	973,163
Investing Activities:			
Gross property additions	(797,014)	(661,154)	(645,262)
Cost of removal net of salvage	(37,369)	(35,440)	(32,111)
Other	11,575	(1,169)	5,017
Net cash used for investing activities	(822,808)	(697,763)	(672,356)
Financing Activities:			
Increase (decrease) in notes payable, net	-	(36,991)	26,994
Proceeds --			
Senior notes	900,000	1,415,000	975,000
Mandatorily redeemable preferred securities	-	-	300,000
Preferred stock	100,000	125,000	-
Common stock	40,000	50,000	-
Capital contributions from parent company	17,541	17,826	43,118
Redemptions --			
First mortgage bonds	-	-	(350,000)
Senior notes	(725,000)	(1,507,000)	(415,602)
Other long-term debt	(1,445)	(943)	(883)
Mandatorily redeemable preferred securities	-	-	(347,000)
Preferred stock	-	-	(70,000)
Payment of preferred stock dividends	(23,639)	(18,181)	(14,176)
Payment of common stock dividends	(437,300)	(430,200)	(431,000)
Other	(16,597)	(14,775)	(30,329)
Net cash used for financing activities	(146,440)	(400,264)	(313,878)
Net Change in Cash and Cash Equivalents	41,709	20,067	(13,071)
Cash and Cash Equivalents at Beginning of Period	42,752	22,685	35,756
Cash and Cash Equivalents at End of Period	\$ 84,461	\$ 42,752	\$ 22,685
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of \$6,832, \$6,367, and \$6,738 capitalized, respectively)	\$188,556	\$185,272	\$230,102
Income taxes (net of refunds)	69,068	161,004	269,043

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

BALANCE SHEETS

At December 31, 2004 and 2003

Alabama Power Company 2004 Annual Report

Assets	2004	2003
	<i>(in thousands)</i>	
Current Assets:		
Cash and cash equivalents	\$ 84,461	\$ 42,752
Receivables --		
Customer accounts receivable	235,221	223,865
Unbilled revenues	96,486	95,953
Under recovered regulatory clause revenues	119,773	16,697
Other accounts and notes receivable	52,145	53,547
Affiliated companies	61,149	48,876
Accumulated provision for uncollectible accounts	(5,404)	(4,756)
Fossil fuel stock, at average cost	57,787	86,993
Vacation pay	36,494	35,530
Materials and supplies, at average cost	237,919	211,690
Prepaid expenses	61,896	78,409
Other	11,269	19,454
Total current assets	1,049,196	909,010
Property, Plant, and Equipment:		
In service	14,636,168	14,224,117
Less accumulated provision for depreciation	5,097,930	4,907,549
	9,538,238	9,316,568
Nuclear fuel, at amortized cost	93,388	93,611
Construction work in progress	470,844	321,316
Total property, plant, and equipment	10,102,470	9,731,495
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	45,455	47,811
Nuclear decommissioning trusts, at fair value	445,634	384,574
Other	44,322	23,708
Total other property and investments	535,411	456,093
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	316,528	321,077
Prepaid pension costs	489,193	446,256
Unamortized debt issuance expense	28,392	23,457
Unamortized loss on reacquired debt	109,403	110,946
Other regulatory assets	46,603	13,092
Other	106,263	91,370
Total deferred charges and other assets	1,096,382	1,006,198
Total Assets	\$12,783,459	\$12,102,796

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

BALANCE SHEETS

At December 31, 2004 and 2003

Alabama Power Company 2004 Annual Report

Liabilities and Stockholder's Equity	2004	2003
	(in thousands)	
Current Liabilities:		
Securities due within one year	\$ 225,005	\$ 526,019
Accounts payable --		
Affiliated	141,096	141,940
Other	198,834	162,314
Customer deposits	49,598	47,507
Accrued taxes --		
Income taxes	28,498	3,679
Other	29,688	22,274
Accrued interest	40,029	46,489
Accrued vacation pay	36,494	35,530
Accrued compensation	76,858	75,726
Other	26,365	34,407
Total current liabilities	852,465	1,095,885
Long-term Debt (See accompanying statements)	3,855,257	3,377,148
Long-term Debt Payable to Affiliated Trusts (See accompanying statements)	309,279	-
Mandatorily Redeemable Preferred Securities (See accompanying statements)	-	300,000
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	1,885,120	1,684,741
Deferred credits related to income taxes	148,395	162,168
Accumulated deferred investment tax credits	205,353	216,309
Employee benefit obligations	194,837	174,036
Deferred capacity revenues	25,056	36,567
Asset retirement obligations	383,621	358,759
Asset retirement obligation regulatory liability	159,230	127,346
Other cost of removal obligations	597,147	572,816
Miscellaneous regulatory liabilities	55,459	86,323
Other	36,989	37,526
Total deferred credits and other liabilities	3,691,207	3,456,591
Total Liabilities	8,708,208	8,229,624
Cumulative Preferred Stock (See accompanying statements)	465,047	372,512
Common Stockholder's Equity (See accompanying statements)	3,610,204	3,500,660
Total Liabilities and Stockholder's Equity	\$12,783,459	\$12,102,796
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION

At December 31, 2004 and 2003

Alabama Power Company 2004 Annual Report

	2004	2003	2004	2003
	(in thousands)		(percent of total)	
Long-Term Debt:				
Long-term notes payable --				
4.875% to 7.125% due 2004	\$ -	\$ 525,000		
5.49% due November 1, 2005	225,000	225,000		
2.65% to 2.80% due 2006	520,000	520,000		
Floating rate (2.09% at 1/1/05) due 2006	195,000	195,000		
3.50% to 7.125% due 2007	500,000	200,000		
3.125% to 5.375% due 2008	410,000	410,000		
Floating rate (2.57% at 1/1/05) due 2009	250,000	-		
4.70% to 6.75% due 2010-2039	1,425,000	1,275,000		
Total long-term notes payable	3,525,000	3,350,000		
Other long-term debt --				
Pollution control revenue bonds --				
Collateralized:				
5.50% due 2024	24,400	24,400		
Variable rates (2.01% to 2.16% at 1/1/05)				
due 2015-2017	89,800	89,800		
Non-collateralized:				
Variable rates (2.01% to 2.16% at 1/1/05)				
due 2021-2031	445,940	445,940		
Total other long-term debt	560,140	560,140		
Capitalized lease obligations	52	1,497		
Unamortized debt premium (discount), net	(4,930)	(8,470)		
Total long-term debt (annual interest requirement -- \$169.0 million)	4,080,262	3,903,167		
Less amount due within one year	225,005	526,019		
Long-term debt excluding amount due within one year	\$3,855,257	\$3,377,148	46.8%	44.7%

STATEMENTS OF CAPITALIZATION (continued)

At December 31, 2004 and 2003

Alabama Power Company 2004 Annual Report

	2004	2003	2004	2003
	(in thousands)		(percent of total)	
Long-term Debt Payable to Affiliated Trusts:				
4.75% through 2007 due 2042*	103,093	-		
5.5% through 2009 due 2042*	206,186	-		
Total long-term debt payable to affiliated trusts (annual interest requirement -- \$16.2 million)	309,279	-	3.8	0.0
Mandatorily Redeemable Preferred Securities:				
\$1,000 liquidation value due 2042 --				
4.75% through 2007*	-	100,000		
5.50% through 2009*	-	200,000		
Total mandatorily redeemable preferred securities	-	300,000	0.0	4.0
Cumulative Preferred Stock:				
\$100 par or stated value -- 4.20% to 4.92%	47,611	47,512		
\$25 par or stated value -- 5.20% to 5.83%	294,105	200,000		
\$100,000 stated value -- 4.95%	123,331	125,000		
Total cumulative preferred stock (annual dividend requirement -- \$24.3 million)	465,047	372,512	5.6	4.9
Common Stockholder's Equity:				
Common stock, par value \$40 per share --	330,000	290,000		
Authorized - 15,000,000 shares				
Outstanding - 8,250,000 shares in 2004 and 7,250,000 shares in 2003				
Paid-in capital	1,955,183	1,927,069		
Retained earnings	1,341,049	1,291,558		
Accumulated other comprehensive income (loss)	(16,028)	(7,967)		
Total common stockholder's equity	3,610,204	3,500,660	43.8	46.4
Total Capitalization	\$8,239,787	\$7,550,320	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, 2004, 2003, and 2002

Alabama Power Company 2004 Annual Report

	Common Stock	Paid-In Capital	Retained Earnings	Other Comprehensive Income (loss)	Total
	<i>(in thousands)</i>				
Balance at December 31, 2001	\$240,000	\$1,850,775	\$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	1,900,563	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	1,927,069	1,291,558	(7,967)	3,500,660
Net income after dividends on preferred stock	-	-	481,171	-	481,171
Issuance of common stock	40,000	-	-	-	40,000
Capital contributions from parent company	-	28,213	-	-	28,213
Other comprehensive income (loss)	-	-	-	(8,061)	(8,061)
Cash dividends on common stock	-	-	(437,300)	-	(437,300)
Other	-	(99)	5,620	-	5,521
Balance at December 31, 2004	\$330,000	\$1,955,183	\$1,341,049	\$(16,028)	\$3,610,204

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

STATEMENTS OF COMPREHENSIVE INCOME

For the Years Ended December 31, 2004, 2003, and 2002

Alabama Power Company 2004 Annual Report

	2004	2003	2002
	<i>(in thousands)</i>		
Net income after dividends on preferred stock	\$481,171	\$472,810	\$461,355
Other comprehensive income (loss):			
Change in additional minimum pension liability, net of tax of \$(2,482), \$(2,301) and \$(2,536), respectively	(4,083)	(3,785)	(4,172)
Change in fair value of marketable securities, net of tax of \$252	414	-	-
Changes in fair value of qualifying hedges, net of tax of \$(4,807), \$1,330 and \$(6,430), respectively	(7,906)	2,188	(10,576)
Less: Reclassification adjustment for amounts included in net income, net of tax of \$2,136, \$4,285 and \$810, respectively	3,514	7,047	1,331
Total other comprehensive income (loss)	(8,061)	5,450	(13,417)
Comprehensive Income	\$473,110	\$478,260	\$447,938

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

NOTES TO FINANCIAL STATEMENTS

Alabama Power Company 2004 Annual Report

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 (SouthernLINC Wireless), 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. SouthernLINC Wireless 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 various other energy-related businesses. Southern Nuclear operates and provides services to Southern Company's nuclear power plants, including the Company's Plant Farley.

The equity method is used for subsidiaries in which the Company has significant influence but does not control and for variable interest entities where the Company is not the primary beneficiary. Certain prior

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

Southern Company is registered as a holding company under the Public Utility Holding Company Act of 1935, as amended (PUHCA). Both Southern Company and its subsidiaries are subject to the regulatory provisions of the PUHCA. In addition, the Company is 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.

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 \$224 million, \$217 million, and \$218 million during 2004, 2003, and 2002, 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 under which Southern Nuclear operates the Company's Plant Farley and provides 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 \$169 million, \$153 million, and \$154 million during 2004, 2003, and 2002, respectively.

The Company jointly owns Plant Greene County with Mississippi Power. The Company has an agreement with Mississippi Power under which the Company operates Plant Greene County, and Mississippi Power reimburses the Company for its proportionate share of expenses which were \$7.2 million in 2004, \$6.6 million in 2003, and \$6.4 million in 2002. See Note 4 for additional information.

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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 \$28.7 million, \$27.5 million, and \$34.5 million in 2004, 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 2004, 2003, and 2002 totaled \$236.9 million, \$209.2 million, and \$211.0 million, respectively.

In June 2003, the Company entered into an agreement with Southern Power under which the Company operates and maintains Plant Harris at cost. In 2004 and 2003, the Company billed Southern Power \$1.8 million and \$0.8 million, respectively, for operation and maintenance. Under a power purchase agreement (PPA) with Southern Power, the Company's purchased power costs from Plant Harris in 2004 and 2003 totaled \$59.0 million and \$41.7 million, respectively. The Company also provides the fuel, at cost, associated with the PPA and the fuel cost recognized by the Company in 2004 was \$65.7 million and \$33.9 million in 2003. 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, 2004 and 2003. See Note 3 under "Retail Rate Adjustment Procedures" and Note 7 under "Purchased Power Commitments" for additional information.

The Company has an agreement with SouthernLINC Wireless to provide digital wireless communications services to the Company. Costs for these services amounted to \$5.3 million, \$4.9 million, and \$4.4 million during 2004, 2003, and 2002, respectively.

Also, see Note 4 for information regarding the Company's ownership in and PPA with Southern Electric Generating Company (SEGCO) and Note 5 for information on certain deferred tax liabilities due to affiliates.

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.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense includes the cost of purchased emission allowances as they are used. Fuel expense also 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 \$61 million in 2004, \$64 million in 2003, and \$63 million in 2002. 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 nuclear fuel in 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. Construction of an on-site dry spent fuel storage facility at Plant Farley is in progress and scheduled for operation in 2005. The onsite storage facility is expected to provide adequate spent fuel storage through 2015 for both units and can be expanded to provide storage through 2025. See Note 7 under "Construction Program" for additional information.

Also, the Energy Policy Act of 1992 established 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 at December 31, 2004 under this law to be approximately \$9 million.

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:

	<u>2004</u>	<u>2003</u>	<u>Note</u>
	(in millions)		
Deferred income tax charges	\$ 317	\$ 321	(a)
Loss on reacquired debt	109	111	(b)
DOE assessments	9	13	(c)
Vacation pay	36	36	(d)
Rate CNP under recovery	18	17	(e)
Natural disaster reserve	38	(13)	(e)
Fuel-hedging assets	6	-	(f)
Other assets	14	(1)	(e)
Asset retirement obligations	(159)	(127)	(a)
Other cost of removal obligations	(597)	(573)	(a)
Deferred income tax credits	(148)	(162)	(a)
Deferred purchased power	(19)	(15)	(e)
Other liabilities	(2)	(5)	(e)
Mine reclamation & remediation	(25)	(33)	(e)
Fuel-hedging liabilities	(10)	(6)	(f)
Total	\$ (413)	\$ (437)	

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 50 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.

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 currently reflected in rates.

Revenues

Energy and other revenues are recognized as services are provided. Capacity revenues are generally recognized on a levelized basis over the appropriate contract periods. Unbilled revenues are accrued at the end of each fiscal period. 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 the actual recoverable costs and amounts billed 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 averaged less than 1 percent of revenues.

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 life of the related property.

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 3.0 percent in 2004, 3.1 percent in 2003, and 3.2 percent in 2002. 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

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 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. Although Statement No. 143 does not permit the continued accrual of future

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retirement costs for long-lived assets that the Company does not have a legal obligation to retire, the Company has received accounting guidance from the Alabama PSC allowing such treatment. Accordingly, the accumulated removal costs for other obligations previously accrued will continue to be reflected on the balance sheets 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, 2004 was \$446 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, liabilities for the removal of these transmission and distribution assets have not been recorded because no reasonable estimate can be made regarding the timing of the obligations. The Company will continue to recognize in the statements of income 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. See "Nuclear Decommissioning" herein for further information on amounts included in rates.

Details of the asset retirement obligations included in the balance sheets are as follows:

	2004	2003
	(in millions)	
Balance beginning of year	\$359	\$ -
Liabilities incurred	-	301
Liabilities settled	-	-
Accretion	25	23
Cash flow revisions	-	35
Balance end of year	\$384	\$359

Nuclear Decommissioning

The Nuclear Regulatory Commission (NRC) requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future 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 only 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, 2004, for Plant Farley were as follows:

Decommissioning periods:	
Beginning year	2017
Completion year	2046
	(in millions)

Site study costs:	
Radiated structures	\$892
Non-radiated structures	63
Total	\$955

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 these estimates.

Annual provisions for nuclear decommissioning are based on an annuity method as approved by the Alabama PSC. The amount expended in 2004 and fund balances were as follows:

	(in millions)
Amount expended in 2004	\$ 18
Accumulated provisions:	
External trust funds, at fair value	\$446
Internal reserves	29
Total	\$475

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 paid into the reserve and deposited into external trusts. Significant assumptions used to determine these costs for ratemaking were an inflation rate of 4.5 percent and a trust earnings rate of 7.0 percent.

The Company filed an application with the NRC in September 2003 to extend the operating license for Plant Farley for an additional 20 years. The NRC is expected to rule on the application by July 2005. If the NRC approves the extension, the annual provision for nuclear decommissioning could decrease, subject to Alabama PSC approval.

Allowance for Funds Used During Construction (AFUDC)

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. All current construction costs are included in retail rates. The composite rate used to determine the amount of AFUDC was 8.6 percent in 2004, 9.0 percent in 2003, and 8.2 percent in 2002. AFUDC, net of income tax, as a percent of net income after dividends on preferred stock was 4.2 percent in 2004, 3.5 percent in 2003, and 3.3 percent in 2002.

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 2004, the Company accrued \$22.6 million to the nuclear refueling outage reserve and at December 31, 2004 the reserve balance was a regulatory asset of \$0.6 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 by either 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.

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Materials and Supplies

Generally, materials and supplies include the average 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 to cover the cost of uninsured damages from major storms to transmission and distribution lines and to generation facilities and other property. 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 2004, the Company accrued \$9.9 million, including an additional amount of \$6.9 million, to the reserve and at December 31, 2004, the reserve balance was a regulatory asset of \$37.7 million. See Note 3 under "Natural Disaster Cost Recovery" for further information.

Environmental Cost Recovery

The Company must comply with 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 may also incur substantial costs to clean up properties. The Company has received authority from the Alabama PSC to recover approved environmental compliance costs through specific retail rate clauses. Within limits approved by the Alabama PSC, these rates are adjusted annually. See Note 3 under "Retail Regulatory Matters" for additional information.

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 of Southern Company's common stock 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.

The pro forma impact of fair-value accounting for options granted on earnings is as follows:

Net Income	As Reported	Pro Forma
	(in thousands)	
2004	\$481,171	\$478,317
2003	472,810	469,599
2002	461,355	457,928

The estimated fair values of stock options granted in 2004, 2003, and 2002 were derived using the Black-Scholes stock option pricing model. The following table shows the assumptions and the weighted average fair values of stock options:

	2004	2003	2002
Interest rate	3.1%	2.7%	2.8%
Average expected life of stock options (in years)	5.0	4.3	4.3
Expected volatility of common stock	19.6%	23.6%	26.3%
Expected annual dividends on common stock	\$1.40	\$1.37	\$1.34
Weighted average fair value of stock options granted	\$3.29	\$3.59	\$3.37

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, 2004	\$4,389	\$4,454
At December 31, 2003	3,903	3,958
Preferred Securities:		
At December 31, 2004	-	-
At December 31, 2003	300	305

The fair values were based on either closing market price or closing price of comparable instruments. See "Variable Interest Entities" herein and Note 6 under "Mandatorily Redeemable Preferred Securities/Long-Term Debt Payable to Affiliate Trusts" for further information regarding the accounting treatment of the preferred securities, which underlie the Company's long-term debt payable to affiliated trusts.

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, changes in the fair value of qualifying cash flow hedges and marketable securities, and changes in additional minimum pension liability, less income taxes and reclassifications for amounts included in net income.

Variable Interest Entities

On March 31, 2004, the Company prospectively adopted FASB Interpretation No. 46R, "Consolidation of Variable Interest Entities," which requires the primary beneficiary of a variable interest entity to consolidate the related assets and liabilities. The adoption of Interpretation No. 46R had no impact on the net income of the Company. However, as a result of the adoption, the Company deconsolidated certain wholly-owned trusts established to issue preferred securities since the Company is not the primary beneficiary of the trusts. Therefore, the investments in these trusts are reflected as Other Investments, and the related loans from the trusts are reflected as Long-term Debt Payable to Affiliated Trusts on the balance sheets. This treatment resulted in a \$9 million increase in both total assets and total liabilities as of March 31, 2004.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trustee, pension plan covering substantially all employees. The plan is funded in accordance with Employee Retirement Income Security Act of 1974, as amended (ERISA), requirements. No contributions to the plan are expected for the year ending December 31, 2005. 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, 2005, postretirement trust contributions are expected to total approximately \$25.3 million.

The measurement date for plan assets and obligations is September 30 for each year.

Pension Plans

The accumulated benefit obligation for the pension plans was \$1.21 billion in 2004 and \$1.10 billion in 2003. Changes during the year in the projected benefit obligations, accumulated benefit obligations, and fair value of plan assets were as follows:

	Projected Benefit Obligations	
	2004	2003
	(in millions)	
Balance at beginning of year	\$1,200	\$1,088
Service cost	30	27
Interest cost	71	68
Benefits paid	(64)	(61)
Plan amendments	1	3
Actuarial (gain) loss	87	75
Balance at end of year	\$1,325	\$1,200
	Plan Assets	
	2004	2003
	(in millions)	
Balance at beginning of year	\$1,583	\$1,419
Actual return on plan assets	157	226
Benefits paid	(64)	(62)
Balance at end of year	\$1,676	\$1,583

Pension plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). Southern Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate,

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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. Southern Company primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk.

	Plan Assets		
	Target	2004	2003
Domestic equity	37%	36%	37%
International equity	20	20	20
Fixed income	26	26	24
Real estate	10	10	11
Private equity	7	8	8
Total	100%	100%	100%

The reconciliations of the funded status with the accrued pension costs recognized in the balance sheets were as follows:

	2004	2003
	(in millions)	
Funded status	\$351	\$383
Unrecognized transition amount	-	(5)
Unrecognized prior service cost	80	87
Unrecognized net (gain) loss	27	(37)
Prepaid pension asset, net	\$458	\$428

The prepaid pension asset, net is reflected in the balance sheets in the following line items:

	2004	2003
	(in millions)	
Prepaid pension asset	\$489	\$446
Employee benefit obligations	(60)	(39)
Intangible asset	10	8
Accumulated other comprehensive income	19	13
Prepaid pension asset, net	\$458	\$428

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

	2004	2003	2002
	(in millions)		
Service cost	\$ 30	\$ 27	\$ 26
Interest cost	71	68	74
Expected return on plan assets	(138)	(138)	(138)
Recognized net gain	(3)	(12)	(20)
Net amortization	4	3	2
Net pension cost (income)	\$ (36)	\$ (52)	\$ (56)

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligations for the pension

plans. At December 31, 2004, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2005	\$ 63.9
2006	64.3
2007	65.3
2008	66.9
2009	69.4
2010 to 2014	\$412.6

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	
	2004	2003
	(in millions)	
Balance at beginning of year	\$441	\$405
Service cost	7	6
Interest cost	24	26
Benefits paid	(18)	(20)
Actuarial (gain) loss	11	24
Balance at end of year	\$465	\$441

	Plan Assets	
	2004	2003
	(in millions)	
Balance at beginning of year	\$186	\$158
Actual return on plan assets	24	25
Employer contributions	20	23
Benefits paid	(18)	(20)
Balance at end of year	\$212	\$186

Postretirement benefits plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal 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	2004	2003
Domestic equity	46%	46%	50%
International equity	13	13	14
Fixed income	34	33	28
Real estate	4	5	5
Private equity	3	3	3
Total	100%	100%	100%

The accrued postretirement costs recognized in the balance sheets were as follows:

	2004	2003
	(in millions)	
Funded status	\$ (253)	\$ (255)
Unrecognized transition obligation	33	37
Unrecognized prior service cost	68	73
Unrecognized net loss (gain)	87	82
Fourth quarter contributions	9	6
Accrued liability recognized in the balance sheets	\$ (56)	\$ (57)

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

	2004	2003	2002
	(in millions)		
Service cost	\$ 7	\$ 6	\$ 5
Interest cost	24	25	25
Expected return on plan assets	(18)	(17)	(16)
Net amortization	9	9	9
Net postretirement cost	\$ 22	\$ 23	\$ 23

In the third quarter 2004, the Company prospectively adopted FASB Staff Position (FSP) 106-2, Accounting and Disclosure Requirements related to the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (the Medicare Act). The Medicare Act provides a 28 percent prescription drug subsidy for Medicare eligible retirees. FSP 106-2 requires recognition of the impacts of the Medicare Act in the accumulated postretirement benefit obligation (APBO) and future cost of service for postretirement medical plans. The effect of the subsidy reduced the Company's expenses for the six months ended December 31, 2004 by approximately \$3.2 million and is expected to have a similar impact on future expenses. The subsidy's impact on the postretirement medical plan APBO was a reduction of approximately \$59.8 million. However, the ultimate impact on future periods is subject to federal regulations governing the subsidy created in the Medicare Act which are being finalized.

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the accumulated benefit obligation for the postretirement plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Act as follows:

	Benefit Payments	Subsidy Receipts	Total
		(in millions)	
2005	\$ 20.7	\$ -	\$ 20.7
2006	22.0	(2.9)	19.1
2007	23.3	(3.1)	20.2
2008	25.2	(3.4)	21.8
2009	27.8	(3.8)	24.0
2010 to 2014	\$173.2	\$(24.3)	\$148.9

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:

	2004	2003	2002
Discount	5.75%	6.00%	6.50%
Annual salary increase	3.50	3.75	4.00
Long-term return on plan assets	8.50	8.50	8.50

The Company determined the long-term rate of return based 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 11 percent for 2004, decreasing gradually to 5 percent through the year 2012, 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, 2004 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	\$41	\$32
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

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percent of an employee's base salary. Total matching contributions made to the plan for 2004, 2003, and 2002 were \$13 million, \$12 million, and \$12 million, respectively.

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.

Environmental Matters

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 related state laws with respect to coal-fired generating facilities at the Company's Plants Miller, Barry, and Gorgas. 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.

The U.S. District Court in Georgia subsequently granted the Company's motion to dismiss for lack of jurisdiction in Georgia. In March 2001, the court granted the EPA's motion to add Savannah Electric as a defendant. As directed by the court, the EPA refiled its amended complaint limiting claims to those brought against Georgia Power and Savannah Electric. In addition, the EPA refiled its claims against the Company in the U.S. District Court for the Northern

District of Alabama. These civil complaints allege violations with respect to eight coal-fired generating facilities in Alabama and Georgia, and they request penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. The EPA has not refiled against Gulf Power or Mississippi Power.

The actions against the Company, Georgia Power, and Savannah Electric were effectively stayed in the spring of 2001 during the appeal of a similar NSR enforcement action against the Tennessee Valley Authority (TVA) before the U.S. Court of Appeals for the Eleventh Circuit. In June 2003, the Court of Appeals issued its ruling in the TVA case, dismissing the appeal for reasons unrelated to the issues in the cases pending against the Company, Georgia Power, and Savannah Electric. In May 2004, the U.S. Supreme Court denied the EPA's petition for review of the case. In June 2004, the U.S. District Court for the Northern District of Alabama lifted the stay in the action against Alabama Power, placing the case back onto the Court's active docket. At this time, no party to the case against Georgia Power and Savannah Electric has sought to reopen that case, which remains administratively closed in the District Court for the Northern District of Georgia.

Since the inception of the NSR proceedings against the Company, Georgia Power, and Savannah Electric, 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. District courts addressing these cases have, to date, issued opinions that reached conflicting conclusions.

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of \$25,000 to \$32,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in any one of these cases 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.

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 (RMRR) exclusion. A coalition of states and environmental organizations has filed petitions for review of these revisions with the U.S. Court of Appeals for the District of Columbia Circuit. The October 2003 RMRR rules have been stayed by the Court of Appeals pending its review of the rules. 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, related legal challenges, and potential state rulemakings cannot be determined at this time.

Generation Interconnection Agreements

In July 2003, the FERC issued its final rule on the standardization of generation interconnection agreements and procedures (Order 2003). Order 2003 shifts much of the financial burden of new transmission investment from the generator to the transmission provider. The FERC has indicated that Order 2003, which was effective January 20, 2004, is to be applied prospectively to interconnection agreements. Subsidiaries of Tenaska, Inc., as counterparties to two previously executed interconnection agreements with the Company, have filed complaints at the FERC requesting that the FERC modify the agreements and that the Company refund a total of \$11 million previously paid for interconnection facilities, with interest. The Company has also received similar requests from other entities totaling \$2.5 million. The Company has opposed such relief, and the proceedings are still pending. The impact of Order 2003 and its subsequent rehearings on the Company and the final results of these matters cannot be determined at this time.

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to nonaffiliates at market-based prices. 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, the retail operating companies, and Southern Power, and found

them and others to be "pivotal suppliers" in their retail service territories and ordered the implementation of several mitigation measures. Southern Company and others sought rehearing of the FERC order, and the FERC delayed the implementation of certain mitigation measures. In April 2004, the FERC issued an order that abandoned the SMA test and adopted a new interim analysis for measuring generation market power. This new interim approach requires utilities to submit a pivotal supplier screen and a wholesale market share screen. If the applicant does not pass both screens, there will be a rebuttable presumption regarding generation market power. The FERC's order also sets forth procedures for rebutting these presumptions and addresses mitigation measures for those entities that are found to have market power. In the absence of specific mitigation measures, the order includes several cost-based mitigation measures that would apply by default. The FERC also initiated a new rulemaking proceeding that, among other things, will adopt a final methodology for assessing generation market power.

In July 2004, the FERC denied Southern Company's request for rehearing, along with a number of others, and reaffirmed the interim tests that it adopted in April. In August 2004, Southern Company submitted a filing to the FERC that included results showing that Southern Company passed the pivotal supplier screen for all markets and the wholesale market share screen for all markets except the Southern Company retail service territory. Southern Company also submitted other analyses to demonstrate that it lacks generation market power. On December 17, 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not at issue. As directed by this order, Southern Company submitted additional information on February 15, 2005 related to generation dominance in its retail service territory. Any new market based rate transactions in Southern Company's retail service territory entered into after February 27, 2005 will be subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. Southern Company, along with other utilities, has also filed an appeal of the FERC's April and July 2004 orders with the U.S. Court of Appeals for the District of Columbia Circuit. The FERC has asked the court to dismiss the appeal on the grounds that it is premature.

In the event that the FERC's default mitigation measures are ultimately applied, the Company may be required to charge cost-based rates for certain wholesale sales in Southern Company's retail service

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territory, which may be lower than negotiated market-based rates. The final outcome of this matter will depend on the form in which the final methodology for assessing generation market power and mitigation rules may be ultimately adopted and cannot be determined at this time.

Natural Disaster Cost Recovery

In September 2004, Hurricane Ivan hit the Gulf Coast of Florida and Alabama and continued north through the Company's service territory causing substantial damage. The related costs charged to the Company's natural disaster reserve were \$57.8 million. During 2004, the Company accrued \$9.9 million to the reserve and at December 31, 2004, the reserve balance was a regulatory asset of \$37.7 million.

In February 2005, the Company requested and received Alabama PSC approval of an accounting order that allows the Company to immediately return certain regulatory liabilities to the retail customers. The order also allows the Company to simultaneously recover from customers an accrual of approximately \$45 million to offset the costs of Hurricane Ivan and restore the natural disaster reserve. The combined effects of this order will have no impact on the Company's net income in 2005.

Retail Regulatory Matters

The Alabama PSC has adopted a Rate Stabilization and Equalization plan (Rate RSE) that provides for periodic annual adjustments based upon the Company's earned return on end-of-period retail common equity. Such annual adjustments are limited to 3 percent. Rates remain unchanged when the return on common equity ranges between 13.0 percent and 14.5 percent. The Alabama PSC has also approved a rate mechanism that provides for adjustments to recognize the placing of new generating facilities in retail service and for the recovery of retail costs associated with certificated purchased power agreements (Rate CNP). Both increases and decreases have been placed into effect since the adoption of these rates.

In accordance with Rate RSE, a 2 percent increase in retail rates was effective in April 2002, amounting to an annual increase of \$55 million. Also, to recover certificated purchased power costs under Rate CNP, an increase of 2.6 percent in retail rates, or \$79 million annually, was effective July 2003. An additional increase of \$25 million annually was effective July 2004 under Rate CNP for new certificated purchased power costs. In April 2005, an annual true-up

adjustment to Rate CNP will decrease retail rates by approximately 0.5 percent, or \$18.5 million annually.

In October 2004, the Alabama PSC approved a request by the Company to amend Rate CNP to also provide for the recovery of retail costs associated with environmental laws and regulations, effective in January 2005. In conjunction with the Alabama PSC's approval, the Company agreed to a moratorium until March 2007 on any retail rate increase under Rate RSE. Any increase in March 2007 would be based upon the earned return on retail common equity at December 31, 2006 and would become effective with the April 2007 billing.

The Company's fuel costs are recovered under Rate ECR (Energy Cost Recovery), which provides for the addition of a fuel and energy cost factor to base rates. In April 2005, this factor is scheduled to increase from its current level.

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

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, as well as 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 \$86 million in 2004, \$87 million in 2003, and \$84 million in 2002 and is included in "Purchased power from affiliates" in the statements of income. The Company accounts for SEGCO using the equity method on the balance sheets.

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. Also, the Company has guaranteed \$50 million principal amount of unsecured senior notes issued by SEGCO for general corporate purposes. Georgia Power has agreed to reimburse

the Company for the pro rata portion of such obligations 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, 2004, the capitalization of SEGCO consisted of \$59 million of equity and \$88 million of debt on which the annual interest requirement is \$3.2 million. SEGCO paid dividends totaling \$12.0 million in 2004, \$2.3 million in 2003, and \$5.8 million in 2002, 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, 2004 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 (in millions)	Accumulated Depreciation (in millions)
Greene County	\$114	\$ 56
Plant Miller Units 1 and 2	776	356

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 operating expenses in the statements of income.

5. INCOME TAXES

Southern Company files a consolidated federal income tax return and a combined State of Georgia income tax return. Under a joint consolidated income tax allocation agreement, as required by the PUHCA, each subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more expense than would be paid if they filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the tax liability.

In 2004, in order to avoid the loss of certain federal income tax credits related to the production of synthetic fuel, Southern Company chose to defer certain deductions otherwise available to the subsidiaries. The cash flow benefit associated with the utilization of the tax credits was allocated to the subsidiary that otherwise would have claimed the available deductions on a separate company basis without the deferral. This allocation concurrently reduced the tax benefit of the credits allocated to those subsidiaries that generated the credits. As the deferred expenses are deducted, the benefit of the tax credits will be repaid to the subsidiaries that generated the tax credits. The Company has recorded \$21.4 million and \$2.3 million payable to these subsidiaries in "Accumulated Deferred Income Taxes" and "Accrued Taxes - Income Tax", respectively, on the balance sheets.

At December 31, 2004, the Company's tax-related regulatory assets and liabilities were \$317 million and \$148 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:

	2004	2003	2002
	(in millions)		
Total provision for income taxes:			
Federal --			
Current	\$ 44	\$111	\$209
Deferred	219	137	41
	263	248	250
State --			
Current	16	26	35
Deferred	34	16	7
	50	42	42
Total	\$313	\$290	\$292

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:

	2004	2003
	(in millions)	
Deferred tax liabilities:		
Accelerated depreciation	\$1,524	\$1,319
Property basis differences	461	466
Premium on reacquired debt	45	46
Pensions	136	128
Fuel clause under recovered	48	-
Other	36	29
Total	2,250	1,988
Deferred tax assets:		
Federal effect of state deferred taxes	112	100
State effect of federal deferred taxes	110	98
Pole attachment rentals	45	27
Unbilled revenue	22	23
Pension and other benefits	16	15
Fuel clause over recovered	-	2
Other	32	72
Total	337	337
Total deferred tax liabilities, net	1,913	1,651
Portion included in current (liabilities)		
assets, net	(28)	34
Accumulated deferred income taxes		
in the balance sheets	\$1,885	\$1,685

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 2004, 2003, and 2002. At December 31, 2004, 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:

	2004	2003	2002
Federal statutory rate	35.0%	35.0%	35.0%
State income tax, net of federal deduction	4.0	3.5	3.5
Non-deductible book depreciation	1.1	1.2	1.3
Differences in prior years' deferred and current tax rates	(0.8)	(0.9)	(1.2)
Other	(1.0)	(1.6)	(0.5)
Effective income tax rate	38.3%	37.2%	38.1%

6. FINANCING

Mandatorily Redeemable Preferred Securities/ Long-Term Debt Payable to Affiliated Trusts

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 and are reflected on the balance sheets as Long-term Debt Payable to Affiliated 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, 2004, preferred securities of \$300 million were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for these trusts and the related securities.

First Mortgage Bonds

The Company has 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 through October 2006. 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, 2004, \$18.7 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 and Preferred Stock

The Company issued a total of \$900 million of unsecured senior notes and \$100 million of preferred stock in 2004. The proceeds of these issues were used to redeem or repay at maturity long-term debt, to repay short-term indebtedness, and for other general corporate purposes.

At December 31, 2004 and 2003, the Company had \$3.5 billion and \$3.4 billion of senior notes outstanding, respectively. These senior notes are subordinate to all secured debt of the Company which amounted to approximately \$286 million at December 31, 2004.

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:

	2004	2003
	(in millions)	
Capitalized leases	\$ -	\$ 1
Senior notes	225	525
Total	\$225	\$526

Debt serial maturities through 2009 applicable to total long-term debt are as follows: \$225 million in 2005; \$715 million in 2006; \$500 million in 2007; \$410 million in 2008; and \$250 million in 2009.

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 \$868 million (including \$504 million of such lines which are dedicated to funding purchase obligations relating to variable rate pollution control bonds), of which \$643 million will expire at various times during 2005. \$225 million of the credit facilities expiring in 2005 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 banks.

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 arrangements. For purposes of calculating these covenants, long-term notes payable to affiliated trusts are excluded from debt but included in capitalization. Exceeding this debt level would result in a default under the credit arrangements. At December 31, 2004, 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, 2004 and 2003, the Company had no extendible commercial notes and no commercial paper outstanding. During 2004, the peak amount outstanding for commercial paper was \$190 million and the average amount outstanding was \$41.5 million. The average annual interest rate on commercial paper in 2004 was 1.51 percent. Commercial paper and extendible commercial notes are included in notes payable on the balance sheets.

At December 31, 2004, 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. There was no material ineffectiveness recorded in earnings in 2004 and 2003.

At December 31, 2004, the fair value of derivative energy contracts was reflected in the financial statements as follows:

	Amounts (in thousands)
Regulatory liabilities, net	\$3,978
Net income	39
Total fair value	\$4,017

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 has energy-related hedges in place through 2007.

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

At December 31, 2004, the Company had \$981 million notional amount of interest rate swaps outstanding with net fair value losses of \$7.2 million as follows:

Cash Flow Hedges

Maturity	Weighted Average	Notional Amount	Fair Value Gain/ (Loss)
	Fixed Rate Paid		
		(in millions)	
2006	1.89	\$195	\$3.2
2007	2.01*	536	5.6
2035	5.68	250	(16.0)

*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 2004 and 2003, the Company settled gains (losses) of \$5.5 million and \$(8) million, respectively, upon termination of certain interest derivatives at the same time it issued debt. These gains (losses) have been deferred in other comprehensive income and will be amortized to interest expense over the life of the original interest derivative, which approximates to the underlying related debt.

For the years 2004, 2003 and 2002, approximately \$6.3 million, \$11.3 million, and \$2.1 million, respectively, of pre-tax losses were reclassified from other comprehensive income to interest expense. For 2005, pre-tax gains of approximately \$0.7 million are expected to be reclassified from other comprehensive income to interest expense. The Company has interest-related hedges in place through 2035.

7. COMMITMENTS

Construction Program

The Company is engaged in continuous construction programs, currently estimated to total \$902 million in 2005, \$921 million in 2006, and \$1.0 billion in 2007. These amounts include \$24 million, \$12 million, and \$11 million in 2005, 2006, and 2007, respectively, for construction expenditures related to contractual purchase commitments for uranium and nuclear fuel conversion, enrichment, and fabrication services included 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, 2004, 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.

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 inspections 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 for facilities owned are currently estimated at \$253 million over the term of the agreements, which are approximately 12 to 14 years per unit. At December 31, 2004, the remaining balance was approximately \$193 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 either prepayments or other deferred charges and assets 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, 2004 were as follows:

Year	Commitments		
	Affiliated	Non-Affiliated (in millions)	Total
2005	\$ 50	\$ 37	\$ 87
2006	50	37	87
2007	50	38	88
2008	50	39	89
2009	50	40	90
2010 and thereafter	13	25	38
Total commitments	\$263	\$216	\$479

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. Coal commitments include forward contract purchases for sulfur dioxide emission allowances. Natural gas purchase commitments contain given 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 Exchange future prices at December 31, 2004. Total estimated minimum long-term commitments at December 31, 2004 were as follows:

Year	Natural Gas	Coal & Nuclear Fuel
	(in millions)	
2005	\$249	\$ 907
2006	195	804
2007	114	713
2008	26	225
2009	26	131
2010 and thereafter	108	97
Total commitments	\$718	\$2,877

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 \$28.3

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million in 2004, \$29.5 million in 2003, and \$29.6 million in 2002. Of these amounts, \$16.3 million, \$19.4 million, and \$19.1 million for 2004, 2003, and 2002, respectively, relates to the rail car leases and are recoverable through the Company's Rate ECR clause. At December 31, 2004, estimated minimum rental commitments for noncancellable operating leases were as follows:

Year	Rail Cars	Vehicles & Other	Total
	(in millions)		
2005	\$17.7	\$11.4	\$ 29.1
2006	14.1	8.6	22.7
2007	6.9	5.7	12.6
2008	6.6	4.0	10.6
2009	4.8	3.6	8.4
2010 and thereafter	27.4	7.2	34.6
Total minimum payments	\$77.5	\$40.5	\$118.0

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 2006 and 2009, and the Company's maximum obligations are \$66 million and \$19.5 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, 2004, the Company had outstanding guarantees related to SEGCO's purchase of certain pollution control facilities and issuance of senior notes, as discussed in Note 4, and to certain residual values of leased assets. See "Operating Leases" above.

8. STOCK OPTION PLAN

Southern Company provides non-qualified stock options to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2004, 1,111 current and former employees of the Company participated in this stock option plan. The maximum number of shares of Southern Company common stock that may be issued under the plan may not exceed 55 million. The prices of options granted to date have been at the fair market value of the shares on the dates of grant. Options granted to date become exercisable pro rata over a

maximum period of three years from the date of grant. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the stock option plan. Activity from 2002 to 2004 for the options granted to the Company's employees under the stock option plan is summarized below:

	Shares Subject to Option	Average Option Price per Share
Balance at December 31, 2001	5,201,605	\$17.56
Options granted	1,332,716	25.26
Options canceled	(12,515)	22.59
Options exercised	(827,883)	15.03
Balance at December 31, 2002	5,693,923	19.72
Options granted	1,201,677	27.98
Options canceled	(6,726)	23.11
Options exercised	(1,043,013)	16.16
Balance at December 31, 2003	5,845,861	22.05
Options granted	1,168,140	29.50
Options canceled	(3,379)	28.82
Options exercised	(1,252,277)	18.07
Balance at December 31, 2004	5,758,345	24.42
Options exercisable:		
At December 31, 2002	2,702,614	
At December 31, 2003	3,171,383	
At December 31, 2004	3,404,264	

The following table summarizes information about options outstanding at December 31, 2004:

	Dollar Price Range of Options		
	13-20	20-26	26-32
Outstanding:			
Shares (in thousands)	1,386	2,032	2,340
Average remaining life (in years)	5.7	6.8	8.6
Average exercise price	\$17.56	\$24.12	\$28.74
Exercisable:			
Shares (in thousands)	1,386	1,609	409
Average exercise price	\$17.56	\$23.83	\$28.00

9. 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 \$10.76 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 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 \$39 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. Both companies, however, 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 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.

10. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2004 and 2003 are as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred Stock
(in millions)			
March 2004	\$ 960	\$202	\$ 91
June 2004	1,059	239	104
September 2004	1,246	415	220
December 2004	971	164	66
March 2003	\$ 890	\$211	\$ 92
June 2003	950	227	107
September 2003	1,216	414	217
December 2003	904	163	57

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

SELECTED FINANCIAL AND OPERATING DATA 2000-2004

Alabama Power Company 2004 Annual Report

	2004	2003	2002	2001	2000
Operating Revenues (in thousands)	\$4,235,991	\$3,960,161	\$3,710,533	\$3,586,390	\$3,667,461
Net Income after Dividends					
on Preferred Stock (in thousands)	\$481,171	\$472,810	\$461,355	\$386,729	\$419,916
Cash Dividends					
on Common Stock (in thousands)	\$437,300	\$430,200	\$431,000	\$393,900	\$417,100
Return on Average Common Equity (percent)	13.53	13.75	13.80	11.89	13.58
Total Assets (in thousands)	\$12,783,459	\$12,102,796	\$11,591,666	\$11,303,605	\$11,228,118
Gross Property Additions (in thousands)	\$797,014	\$661,154	\$645,262	\$635,540	\$870,581
Capitalization (in thousands):					
Common stock equity	\$3,610,204	\$3,500,660	\$3,377,740	\$3,310,877	\$3,195,772
Preferred stock	465,047	372,512	247,512	317,512	317,512
Mandatorily redeemable preferred securities	-	300,000	300,000	347,000	347,000
Long-term debt payable to affiliated trusts	309,279	-	-	-	-
Long-term debt	3,855,257	3,377,148	2,872,609	3,742,346	3,425,527
Total (excluding amounts due within one year)	\$8,239,787	\$7,550,320	\$6,797,861	\$7,717,735	\$7,285,811
Capitalization Ratios (percent):					
Common stock equity	43.8	46.4	49.7	42.9	43.9
Preferred stock	5.6	4.9	3.6	4.1	4.4
Mandatorily redeemable preferred securities	-	4.0	4.4	4.5	4.8
Long-term debt payable to affiliated trusts	3.8	-	-	-	-
Long-term debt	46.8	44.7	42.3	48.5	46.9
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0
Security Ratings:					
First Mortgage Bonds -					
Moody's	A1	A1	A1	A1	A1
Standard and Poor's	A	A	A	A	A
Fitch	AA-	A+	A+	A+	AA-
Preferred Stock -					
Moody's	Baa1	Baa1	Baa1	Baa1	a2
Standard and Poor's	BBB+	BBB+	BBB+	BBB+	BBB+
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	1,170,814	1,160,129	1,148,645	1,139,542	1,132,410
Commercial	208,547	204,561	203,017	196,617	193,106
Industrial	5,260	5,032	4,874	4,728	4,819
Other	753	757	789	751	745
Total	1,385,374	1,370,479	1,357,325	1,341,638	1,331,080
Employees (year-end):	6,745	6,730	6,715	6,706	6,871

SELECTED FINANCIAL AND OPERATING DATA 2000-2004 (continued)
Alabama Power Company 2004 Annual Report

	2004	2003	2002	2001	2000
Operating Revenues (in thousands):					
Residential	\$1,346,669	\$1,276,800	\$1,264,431	\$1,138,499	\$1,222,509
Commercial	980,771	913,697	882,669	829,760	854,695
Industrial	948,528	844,538	788,037	763,934	859,668
Other	16,860	16,428	16,080	15,480	15,835
Total retail	3,292,828	3,051,463	2,951,217	2,747,673	2,952,707
Sales for resale - non-affiliates	483,839	487,456	474,291	485,974	461,730
Sales for resale - affiliates	308,312	277,287	188,163	245,189	166,219
Total revenues from sales of electricity	4,084,979	3,816,206	3,613,671	3,478,836	3,580,656
Other revenues	151,012	143,955	96,862	107,554	86,805
Total	\$4,235,991	\$3,960,161	\$3,710,533	\$3,586,390	\$3,667,461
Kilowatt-Hour Sales (in thousands):					
Residential	17,368,321	16,959,566	17,402,645	15,880,971	16,771,821
Commercial	13,822,926	13,451,757	13,362,631	12,798,711	12,988,728
Industrial	22,854,399	21,593,519	21,102,568	20,460,022	22,101,407
Other	198,253	203,178	205,346	198,102	205,827
Total retail	54,243,899	52,208,020	52,073,190	49,337,806	52,067,783
Sales for resale - non-affiliates	15,483,420	17,085,376	15,553,545	15,277,839	14,847,533
Sales for resale - affiliates	7,233,880	9,422,301	8,844,050	8,843,094	5,369,474
Total	76,961,199	78,715,697	76,470,785	73,458,739	72,284,790
Average Revenue Per Kilowatt-Hour (cents):					
Residential	7.75	7.53	7.27	7.17	7.29
Commercial	7.10	6.79	6.61	6.48	6.58
Industrial	4.15	3.91	3.73	3.73	3.89
Total retail	6.07	5.84	5.67	5.57	5.67
Sales for resale	3.49	2.88	2.72	3.03	3.11
Total sales	5.31	4.85	4.73	4.74	4.95
Residential Average Annual					
Kilowatt-Hour Use Per Customer	14,894	14,688	15,198	13,981	14,875
Residential Average Annual					
Revenue Per Customer	\$1,155	\$1,106	\$1,104	\$1,002	\$1,084
Plant Nameplate Capacity					
Ratings (year-end) (megawatts)	12,216	12,174	12,153	12,153	12,122
Maximum Peak-Hour Demand (megawatts):					
Winter	9,556	10,409	9,423	9,300	9,478
Summer	10,938	10,462	10,910	10,241	11,019
Annual Load Factor (percent)	63.2	64.1	62.9	62.5	59.3
Plant Availability (percent):					
Fossil-steam	87.8	85.9	85.8	87.1	89.4
Nuclear	88.7	94.7	93.2	83.7	88.3
Source of Energy Supply (percent):					
Coal	56.5	56.5	55.5	56.8	63.0
Nuclear	16.4	17.0	17.1	15.8	16.9
Hydro	5.6	7.0	5.1	5.1	2.9
Gas	8.9	7.6	11.6	10.7	4.9
Purchased power -					
From non-affiliates	5.4	4.1	4.0	4.4	4.6
From affiliates	7.2	7.8	6.7	7.2	7.7
Total	100.0	100.0	100.0	100.0	100.0

DIRECTORS AND OFFICERS

Alabama Power Company 2004 Annual Report

Directors

Whit Armstrong
President, Chairman and CEO,
The Citizens Bank

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

H. Allen Franklin¹
Chairman, President and CEO,
Southern Company

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

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

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

Patricia M. King
President and CEO,
Sunny King Automotive Group

James K. Lowder
Chairman,
The Colonial Company

Wallace D. Malone, Jr.
Vice Chairman,
Wachovia Corporation

Charles D. McCrary
President and CEO,
Alabama Power Company

Dr. Malcolm Portera
Chancellor, The University of
Alabama System

Robert D. Powers
President, The Eufaula Agency

David M. Ratcliffe²
Chairman, President and CEO,
Southern Company

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

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

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

James W. Wright
Chairman, President and CEO,
First Tuskegee Bank

Officers

Charles D. McCrary
President and Chief Executive Officer

William B. Hutchins, III³
Executive Vice President, Chief
Financial Officer and Treasurer

Art P. Beattie⁴
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

Philip C. Raymond⁵
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
Vice President

Donald R. Horsley⁶
Vice President

Gerald L. Johnson
Vice President, Birmingham
Division

Marsha S. Johnson⁷
Vice President, Birmingham
Division

William B. Johnson
Vice President

Barbara J. Knight
Vice President

Ellen N. Lindemann
Vice President

Gordon G. Martin
Vice President, Southern Division

Myrna J. Pittman⁸
Vice President

Donald W. Reese
Vice President

R. Michael Saxon
Vice President, Southeast Division

Julia H. Segars
Vice President

Julian H. Smith, Jr.
Vice President

W. Ronald Smith
Vice President, Eastern Division

Zeke W. Smith⁹
Vice President

Cheryl A. Thompson
Vice President, Mobile Division

Terry H. Waters
Vice President, Western Division

E. Wayne Boston
Assistant Secretary and
Assistant Treasurer

J. Randy DeRieux
Assistant Treasurer

Robert Cole Giddens
Assistant Comptroller

Ceila H. Shorts
Assistant Secretary

Kay I. Worley
Assistant Secretary

**All information as of
December 31, 2004
except as noted below**

¹ Resigned 7/04

² Elected 7/04

³ Retired 2/05

⁴ Elected 2/05

⁵ Elected 2/05

⁶ Elected 3/05

⁷ Resigned 2/05

⁸ Elected 2/05

⁹ Elected 2/05

CORPORATE INFORMATION

Alabama Power Company 2004 Annual Report

General

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

Profile

The Company 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 almost 1.4 million customers within its service area of approximately 45,000 square miles. In 2004, retail energy sales accounted for 70 percent of the Company's total sales of 77.0 billion kilowatt-hours.

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

Trustee, Registrar and Interest Paying Agent

All series of First Mortgage Bonds,
Senior Notes and Trust Preferred Securities
JPMorgan Chase Bank, N.A.
Institutional Trust Services
4 New York Plaza, 15th Floor
New York, NY 10004

Registrar, Transfer Agent and Dividend Paying Agent

All series except 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 as of December 31, 2004, was 1,766.**

Form 10-K

**A copy of the 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

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(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