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GEORGIA POWER
A SOUTHERN COMPANY

July 30, 2003

Docket Nos.: 50-321 50-424
50-366 50-425

Director of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, D.C. 20555-0001

Edwin I. Hatch Nuclear Plant
Vogtle Electric Generating Plant
Licensee Guarantees of Payment of Deferred Premiums (10 CFR 140.21)

Ladies and Gentlemen:

Enclosed you will find the following financial information pursuant to Section 140.21 of 10 CFR Part 140 that each licensee is required to furnish as a guarantee of payment of deferred premiums for each operating reactor over 100 MW(e):

1. An Annual Report containing certified financial statements for calendar year 2002.
2. A set of quarterly financial statements for the period ending June 30, 2003.
3. A one year projected Cash Flows Statement for period January 1, 2004, through December 31, 2004.

Should you have any questions in connection with our response, please contact me at (404) 506-7952 or Jan Miller at (404) 506-6690.

Very truly yours,

Robert A. Aubuchon

M004

Enclosures

cc: Southern Nuclear Operating Company
Mr. J. D. Woodard, Executive Vice President
Mr. H. L. Sumner, Jr., Vice President, Plant Hatch
Mr. J. T. Gasser, Vice President, Plant Vogtle
Mr. G. R. Frederick, General Manager - Plant Hatch
Mr. W. F. Kitchens, General Manager - Plant Vogtle
Document Services RTYPE: CHA02.004; CVC7000

U. S. Nuclear Regulatory Commission
Mr. L. A. Reyes, Regional Administrator
Mr. S. D. Bloom, NRR Project Manager - Hatch
Mr. F. Rinaldi, NRR Project Manager - Vogtle
Mr. D. S. Simpkins, Senior Resident Inspector - Hatch
Mr. J. Zeiler, Senior Resident Inspector - Vogtle

GEORGIA POWER COMPANY
CONDENSED STATEMENTS OF INCOME (UNAUDITED)
(Stated in Thousands of Dollars)

	For the Three Months Ended June 30, 2003	For the Three Months Ended June 30, 2002	For the Six Months Ended June 30, 2003	For the Six Months Ended June 30, 2002
OPERATING REVENUES:				
Retail sales	$1,041,604	$1,062,070	$2,007,311	$1,966,984
Sales for resale--				
Non-affiliates	$59,452	72,322	$133,438	$122,372
Affiliates	$46,365	25,282	$93,851	$41,789
Other revenues	$42,672	44,811	$81,931	$80,103
Total operating revenues	1,190,093	1,204,485	2,316,531	2,211,248
OPERATING EXPENSES:				
Operation--				
Fuel	271,428	255,792	513,931	483,169
Purchased power--				
Non-affiliates	62,052	65,280	134,088	103,070
Affiliates	121,605	98,716	235,448	157,496
Other	199,487	204,694	385,477	378,514
Maintenance	107,628	108,461	218,572	212,315
Depreciation and amortization	86,003	101,206	171,745	197,003
Taxes other than income taxes	49,290	49,857	102,465	99,432
Total operating expenses	897,493	884,006	1,761,726	1,630,999
OPERATING INCOME	292,600	320,479	554,805	580,249
OTHER INCOME (EXPENSE):				
Interest expense, net of amounts capitalized	(47,925)	(41,453)	(92,288)	(82,048)
Distributions on preferred securities of subsidiaries	(14,919)	(15,647)	(29,838)	(30,423)
Other income (expense), net	25,169	8,519	31,152	6,158
Total other income and (expense)	(37,675)	(48,581)	(90,974)	(106,313)
EARNINGS BEFORE INCOME TAXES	254,925	271,898	463,831	473,936
Income taxes	96,231	100,933	171,699	176,058
NET INCOME	158,694	170,965	292,132	297,878
DIVIDENDS ON PREFERRED STOCK	167	167	335	335
NET INCOME AFTER DIVIDENDS ON PREFERRED STOCK	$158,527	$170,798	$291,797	$297,543

Note: Certain prior period amounts have been reclassified to conform with current period presentation.

GEORGIA POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)
(Stated in Thousands of Dollars)

	At June 30, 2003	At June 30, 2002
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$10,799	$211,173
Receivables --		
Customer accounts receivable	279,288	285,049
Unbilled revenues	132,307	140,715
Under recovered regulatory clause revenue	125,052	124,589
Other accounts and notes receivable	74,943	91,783
Affiliated companies	38,691	29,809
Accumulated provision for uncollectible accounts	(5,825)	(6,442)
Fossil fuel stock, at average cost	142,705	182,770
Materials and supplies, at average cost	271,364	271,613
Other	62,396	89,843
Total Current Assets	1,131,720	1,420,902
PROPERTY, PLANT AND EQUIPMENT:		
In service	17,894,675	17,108,341
Less accumulated provision for depreciation	7,183,011	7,348,515
	10,711,664	9,759,826
Nuclear fuel, at amortized cost	112,508	119,578
Construction work in progress	403,677	590,576
Total Property, Plant and Equipment	11,227,849	10,469,980
OTHER PROPERTY AND INVESTMENTS:		
Equity investments in unconsolidated subsidiaries	38,095	35,016
Nuclear decommissioning trusts	387,601	358,821
Other	29,480	30,904
Total Other Property and Investments	455,176	424,741
DEFERRED CHARGES AND OTHER ASSETS:		
Deferred charges related to income taxes	516,618	533,871
Prepaid pension costs	370,464	307,755
Unamortized debt issuance expense	75,344	71,367
Unamortized premium on reacquired debt	177,496	167,971
Asset retirement obligation regulatory asset	11,902	-
Other	151,219	161,931
Total Deferred Charges and Other Assets	1,303,043	1,242,895
TOTAL ASSETS	$14,117,788	$13,558,518

GEORGIA POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)
(Stated in Thousands of Dollars)

	At June 30, 2003	At June 30, 2002
LIABILITIES AND STOCKHOLDER'S EQUITY		
CURRENT LIABILITIES:		
Securities due within one year	$2,215	$766,293
Notes payable	340,044	832,944
Accounts payable --		
Affiliated companies	115,804	117,089
Other	259,774	295,580
Customer deposits	99,418	89,193
Taxes accrued		
Income taxes	80,085	93,375
Other	91,031	94,231
Interest accrued	65,900	73,836
Vacation pay accrued	40,844	41,391
Other	126,845	96,149
Total Current Liabilities	1,221,960	2,500,081
LONG-TERM DEBT	3,663,476	2,196,422
DEFERRED CREDITS AND OTHER LIABILITIES:		
Accumulated deferred income taxes	2,238,686	2,162,674
Deferred credits related to income taxes	200,822	221,014
Accumulated deferred investment tax credits	318,750	331,238
Employee benefits provisions	247,634	251,758
Asset retirement obligations	484,323	-
Other	336,897	422,346
Total Deferred Credits and Other Liabilities	3,827,112	3,389,030
COMPANY OBLIGATED MANDATORILY REDEEMABLE PREFERRED SECURITIES OF SUBSIDIARY TRUSTS HOLDING COMPANY JUNIOR SUBORDINATED NOTI	940,000	1,229,250
PREFERRED STOCK	14,569	14,569
COMMON STOCKHOLDER'S EQUITY:		
Common stock	344,250	344,250
Paid-in capital	2,165,789	1,987,954
Premium on preferred stock	40	40
Retained earnings	1,954,415	1,896,885
Accumulated other comprehensive income	(13,823)	37
Total Common Stockholder's Equity	4,450,671	4,229,166
TOTAL LIABILITIES AND STOCKHOLDER'S EQUITY	$14,117,788	$13,558,518

GEORGIA POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS (UNAUDITED)
(Stated in Thousands of Dollars)

	FOR THE SIX MONTHS ENDED JUNE 2003	2002
OPERATING ACTIVITIES:		
Net income	$292,132	$297,878
Adjustments to reconcile net income to		
net cash provided by operating activities --		
Depreciation and amortization	204,285	195,235
Deferred income taxes and investment tax credits, net	108,809	22,448
Pension, postretirement, and other employee benefits	(17,372)	(27,239)
Other, net	8,167	15,816
Changes in certain current assets and liabilities --		
Receivables, net	33,395	56,317
Fossil fuel stock	(22,658)	19,988
Materials and supplies	(8,000)	7,625
Other current assets	31,641	182
Accounts payable	(141,008)	(75,937)
Taxes accrued	16,600	26,551
Other current liabilities	2,201	16,517
NET CASH PROVIDED FROM OPERATING ACTIVITIES	508,192	555,381
INVESTING ACTIVITIES:		
Gross property additions	(370,727)	(434,402)
Cost of removal net of salvage	(10,786)	(32,826)
Sales of property	-	387,212
Other	(61,789)	(21,526)
NET CASH USED FOR INVESTING ACTIVITIES	(443,302)	(101,542)
FINANCING ACTIVITIES:		
Increase (decrease) in notes payable, net	(17,633)	85,407
Proceeds --		
Senior notes	700,000	-
Preferred securities	-	440,000
Capital contributions from parent company	9,748	5,397
Redemptions --		
First mortgage bonds	-	(1,860)
Pollution control bonds	-	(7,800)
Senior notes	(465,000)	(300,000)
Capital distributions to parent company		(200,000)
Payment of preferred stock dividends	(393)	(344)
Payment of common stock dividends	(282,900)	(271,450)
Other	(14,786)	(15,276)
NET CASH PROVIDED FROM FINANCING ACTIVITIES	(70,964)	(265,926)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(6,074)	187,913
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	16,872	23,260
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$10,798	$211,173

Note: Certain prior period amounts have been reclassified to conform with current period presentation.

GEORGIA POWER COMPANY PROJECTED STATEMENT OF CASH FLOWS 2004 FORECAST (Stated in Thousands of Dollars)

	2004 FORECAST
OPERATING ACTIVITIES	
Net income before preferred dividends	$657,554
Principal noncash items-	
Depreciation and amortization	580,872
Deferred income taxes, net	(7,047)
Allowance for equity funds used during construction	(17,786)
Deferred nuclear outage costs	(3,644)
Pension, postretirement and other employee benefits	7,468
Other, net	59,991
Change in current assets & liabilities-	
Receivables	(24,392)
Inventories	(10,457)
Accounts payable	15,392
Other current assets and liabilities	56,223
NET CASH PROVIDED FROM OPERATING ACTIVITIES	1,314,174
INVESTING ACTIVITIES	
Gross property additions	(1,102,761)
Cost of removal, net of salvage	3,791
Allowance for equity funds used during construction	17,786
Other property and investments	(5,720)
NET CASH USED FOR INVESTING ACTIVITIES	(1,086,904)
FINANCING ACTIVITIES	
Increase in notes payable, net	21,809
Proceeds -	
Senior notes	380,000
Capital contributions from parent company	146,000
Redemptions -	
Senior notes	(150,000)
Capitalized leases	(2,707)
Payment of preferred stock dividends	(672)
Payment of common stock dividends	(614,100)
Other	(7,600)
NET CASH USED FOR FINANCING ACTIVITIES	(227,270)
NET INC (DEC) IN CASH AND TEMPORARY CASH INVESTMENTS	$0
CASH AND TEMPORARY CASH INVESTMENTS AT BEG OF PERIOD	$15,000
CASH AND TEMPORARY CASH INVESTMENTS AT END OF PERIOD	$15,000

2002 Annual Report

GEORGIA POWER

A SOUTHERN COMPANY

CONTENTS

Georgia Power Company 2002 Annual Report

SUMMARY

	2002	2001	Percent Change
Financial Highlights *(in millions)*:			
Operating revenues	**$4,822**	$4,966	(2.9)
Operating expenses	**$3,618**	$3,754	(3.6)
Net income after dividends on preferred stock	**$618**	$610	1.2
Operating Data:			
Kilowatt-hour sales *(in millions)*:			
Retail	**75,432**	72,545	4.0
Sales for resale – non-affiliates	**8,069**	8,110	(0.5)
Sales for resale – affiliates	**3,963**	3,133	26.5
Total	**87,464**	83,788	4.4
Customers served at year-end *(in thousands)*	**1,997**	1,954	2.2
Peak-hour demand *(in megawatts)*	**14,597**	14,294	2.1
Capitalization Ratios *(percent)*:			
Common stock equity	**52.2**	53.9	
Preferred stock	**0.2**	0.2	
Company obligated mandatorily redeemable preferred securities	**11.1**	9.6	
Long-term debt	**36.5**	36.3	
Return on Average Common Equity *(percent)*	**13.99**	14.12	
Ratio of Earnings to Fixed Charges *(times)*	**5.07**	4.79	

2002 was an excellent year for Georgia Power in terms of financial and operational excellence.

Georgia Power's earnings for 2002 totaled $618 million, an $8 million, or 1.2 percent increase, from 2001. Hot weather in September and below-normal temperatures at the end of the year kept electricity sales strong despite the weak economy. Our employees' focus on executing the company's strategy ensured another successful year. We earned a 13.99 percent return on average common equity during 2002.

The company prospered last year because we were effective at managing the fundamentals of our business – generating and supplying power to 2 million customers. Our total sales of electricity climbed 4.4 percent as we maintained a solid reliability record. We also continued a $220 million capital expansion program to meet transmission load growth. Last year, we completed 82 miles of new transmission and 18 new substations, much of it by the time hot weather hit last summer.

As testament to our reputation across the region, our crews traveled to Lafayette and Baton Rouge, La., last year to help with power restoration in the wake of hurricanes Lili and Isidore. And more than 700 employees went to North Carolina, helping crews from Duke Power complete a massive power restoration following the worst ice storm in that company's history. As always, our people received accolades for their professionalism and productivity. It's not surprising that three Georgia Power Linemen – Derek Bell, Chris Jarrard, and Scott Simpson – won the overall International Lineman's Rodeo in Kansas City last fall.

To keep up with continuing growth in our market, we began purchasing power last summer from three new natural gas, combined-cycle units owned by Southern Power – two at Plant Wansley totaling 1,132 megawatts and one at Plant Franklin with 571 megawatts. We also retired 11 small units – 415 megawatts – at plants Arkwright, Atkinson, and Mitchell after determining it was more economical to retire the units than to continue operating them.

We made great strides in our efforts to install new environmental controls at some of our biggest plants. We recently brought on line selective catalytic reduction (SCR) systems on two units at Plant Bowen and one at Plant Hammond. And we're installing SCRs on the other two units at Bowen and two units at Plant Wansley, which will all be operational this spring. These controls will help the state comply with federal ozone standards.

In fact, Georgia Power has invested more than $1 billion in the past several years on measures and controls to reduce emissions. These efforts have lowered our emissions of sulfur dioxide by 42 percent and will cut emissions of nitrogen oxides by as much as 85 percent by this spring at key facilities.

Our environmental efforts are just one way we demonstrate our commitment to being a Citizen Wherever We Serve. In 2002, our community and economic development organization celebrated 75 years of generating growth in Georgia and was again ranked one of the best in the world by *Site Selection* magazine. We were credited with helping to bring nearly $926 million in new capital investment and 8,500 new jobs to Georgia.

The Georgia Minority Supplier Development Council recognized Georgia Power with two key awards last year for our commitment to diversity. The company also won two national awards for our efforts to expand supplier diversity, including the U.S. Small Business Administration Dwight D. Eisenhower Award for Excellence among utilities and the Edison Electric Institute Minority Business Development Committee Award for advancement of minority- and female-owned businesses. Supplier diversity is a key goal for our company, and it's gratifying to see our efforts recognized locally and nationally.

For the third straight year, Southern Company's National Accounts program was named one of the top three in the nation for customer satisfaction. The award is given annually by the Edison Electric Institute's Customer Advisory Group, which surveys hundreds of the nation's largest commercial customers and identifies utilities that excel in providing customer service and value.

Georgia Power's Customer Care Center also won an IEX award for our use of a new workforce planning software program that cuts costs while improving customer service. Georgia Power handles approximately 6.5 million phone calls each year. The software helps us forecast call volumes and schedule the appropriate workforce, especially when call loads are predicted to be heaviest. It has enabled us to reduce overtime costs by 76 percent – an average savings of $400,000 per year. Call service levels have also improved 44 percent with the new system, while the average time that it takes to answer a call has dropped 70 seconds.

We launched Premium Surge Protection, a service that protects electronics and motor-driven appliances by preventing lightning-related surges from entering the home. We also introduced FlatBill, offering customers a customized monthly fixed electricity bill. Georgia Power is the only electric utility in the country to offer a pricing product similar to FlatBill, which protects customers from variations in their bill due to weather, usage and fuel price for the contract year. Nearly 60,000 customers signed up last year.

It's very clear to me that the work our employees do every day and their commitment to the company are what make us successful. We're already making progress on our goals for 2003, and we remain committed to excellence in service, reliability, value, and stewardship while building our corporate reputation, market share, and profitability.

Sincerely,

David Ratcliffe
March 14, 2003

MANAGEMENT'S REPORT
Georgia Power Company 2002 Annual Report

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

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

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

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

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

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

David M. Ratcliffe
President and Chief Executive Officer

Allen L. Leverett
Executive Vice President, Treasurer
and Chief Financial Officer
February 17, 2003

INDEPENDENT AUDITORS' REPORT

Georgia Power Company:

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

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

In our opinion, the 2002 financial statements (pages 19-41) present fairly, in all material respects, the financial position of Georgia Power Company at December 31, 2002, and the results of its operations and its cash flows for the year then ended, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
February 17, 2003

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

To Georgia Power Company:

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

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

In our opinion, the financial statements (pages 16-36) referred to above present fairly, in all material respects, the financial position of Georgia Power Company as of December 31, 2001 and 2000, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

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

Arthur Andersen LLP

Atlanta, Georgia
February 13, 2002

RESULTS OF OPERATIONS

Earnings

Georgia Power Company's 2002 earnings totaled $618 million, representing an $8 million (1.2 percent) increase over 2001. Operating income declined slightly in 2002. Lower retail and wholesale revenues, higher other operating and maintenance expenses and increased purchased power capacity expenses were significantly offset by lower depreciation and amortization expense as a result of a Georgia Public Service Commission (GPSC) retail rate order effective January 2002. The increase in net income for 2002 is attributed to lower financing costs and a lower effective tax rate due to the realization of certain state tax credits. The Company's 2001 earnings totaled $610 million, representing a $51 million (9.1 percent) increase over 2000. Operating income was lower in 2001 compared to 2000 due to the impact of mild weather on retail revenues; however, overall net income improved due to lower financing costs and non-operating expenses and a lower effective tax rate resulting from various factors including property donations and positive resolution of outstanding tax issues. The Company's 2000 earnings totaled $559 million, representing an $18 million (3.3 percent) increase over the prior year due to increased sales and continued control of operating expenses.

	Amount	Increase (Decrease) From Prior Year		
	2002	2002	2001	2000
	(in millions)			
Operating revenues	$ 4,822	$ (144)	$95	$414
Fuel	1,003	64	(79)	98
Purchased power	685	(87)	175	206
Other operation and maintenance	1,325	85	41	4
Depreciation and amortization	403	(197)	(19)	66
Taxes other than income taxes	202	(1)	(1)	2
Total operating expenses	3,618	(136)	117	376
Operating income	1,204	(8)	(22)	38
Other income and (expense)	(229)	9	76	(11)
Less - Income taxes	357	(7)	3	9
Net income	$ 618	$ 8	$51	$ 18

Revenues

Operating revenues in 2002, 2001, and 2000 and the percent of change from the prior year are as follows:

	Amount		
	2002	2001	2000
	(in millions)		
Retail – prior year	$4,349	$4,317	$4,050
Change in -			
Base rates	(118)	-	(24)
Sales growth and other	2	90	53
Weather	82	(107)	55
Fuel cost recovery and other clauses	(27)	49	183
Total retail	4,288	4,349	4,317
Sales for resale -			
Non-affiliates	271	366	298
Affiliates	98	100	96
Total sales for resale	369	466	394
Other operating revenues	165	151	160
Total operating revenues	$4,822	$4,966	$4,871
Percent change	(2.9%)	2.0%	9.3%

Retail base revenues of $3.068 billion in 2002 decreased by $34 million (1.1 percent) from 2001 primarily due to a base rate reduction effective January 2002 under the retail rate order and generally lower prices to large business customers. This decrease was partially offset by a 10.1 percent increase in residential kilowatt-hour sales due to warmer weather.

Retail base revenues of $3.102 billion in 2001 decreased $17 million (0.5 percent) from 2000, primarily due to a 2.5 percent decrease in retail kilowatt-hour sales from the prior year. Milder-than-normal weather and a slowdown in the economy contributed to the decline in such sales. Retail base revenues of $3.119 billion in 2000 increased $84 million from the prior year primarily due to a 4.9 percent increase in retail kilowatt-hour sales due to warmer summer temperatures and colder winter weather.

Electric rates include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. Under these fuel cost recovery provisions, fuel revenues generally equal fuel expenses -- including the fuel component of purchased energy -- and do not affect net income. As of December 31, 2002, the Company had $118 million in underrecovered fuel costs. Under a GPSC rate order, the fuel cost recovery rate was increased effective June 2001 to allow for an estimated 24-month recovery of the deferred underrecovered fuel costs. Also, effective January 1, 2002, the Company is allowed to collect a carrying cost on average underrecovered fuel balances.

Wholesale revenues from sales to non-affiliated utilities were:

	2002	2001	2000
	(in millions)		
Unit power sales --			
Capacity	$ 34	$ 26	$ 30
Energy	34	35	25
Other power sales --			
Capacity	41	72	67
Energy	162	233	176
Total	$271	$366	$298

Revenues from unit power contracts increased $7 million in 2002 due to higher capacity charges and $6 million in 2001 due to increased energy sales, while remaining constant in 2000. See Note 7 to the financial statements for further information regarding these sales. Revenues from other non-affiliated sales decreased $102 million (33.4 percent) in 2002 and increased $62 million in 2001 and $88 million in 2000 primarily due to fluctuations in off-system sale transactions that were generally offset by corresponding purchase transactions. These transactions had no significant effect on income. In 2002, revenues also decreased $37 million as a result of transferring Plant Dahlberg to Southern Power Company (Southern Power) in July 2001.

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

Other operating revenues in 2002 increased $14 million (9.5 percent) primarily due to the collection of new late payment fees approved under the retail rate order effective January 2002 and revenues from outdoor lighting and the transmission of electricity. Other operating revenues in 2001 decreased $9 million (5.3 percent) primarily due to lower gains on the sale of generating plant emission allowances, partially offset by increased revenues from the transmission of electricity and from the rental of electric equipment and property. Other operating revenues in 2000 increased $39 million (32.8 percent) due to increased revenues from the transmission of electricity and gains on the sale of generating plant emission allowances.

Kilowatt-hour (KWH) sales for 2002 and the percent change by year were as follows:

	KWH	Percent Change		
	2002	2002	2001	2000
	(in billions)			
Residential	22.1	10.1%	(2.8)%	6.6%
Commercial	27.0	1.7	3.4	8.1
Industrial	25.7	1.5	(8.0)	0.9
Other	0.6	1.7	2.5	3.2
Total retail	75.4	4.0	(2.5)	4.9
Sales for resale -				
Non-affiliates	8.1	(0.5)	25.5	27.7
Affiliates	4.0	26.5	28.7	35.6
Total sales for resale	12.1	7.0	26.3	29.8
Total sales	87.5	4.4	0.5	7.1

Residential sales increased 10.1 percent in 2002 due to the effect of the warmer weather. Commercial and industrial sales increased 1.7 percent and 1.5 percent, respectively, due to corresponding increases of 2.6 percent and 2.4 percent, respectively, in customers. Residential sales decreased 2.8 percent in 2001 due to milder-than-normal weather. Commercial sales increased 3.4 percent due to an increase in customers, while industrial sales decreased 8.0 percent due to an economic slowdown. Residential and commercial sales increased 6.6 percent and 8.1 percent, respectively, in 2000 due to weather and economic growth. Industrial sales remained fairly constant in 2000.

Expenses

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

	2002	2001	2000
Total generation (billions of KWH)	**70.4**	68.9	73.6
Sources of generation (percent) --			
Coal	**77.4**	74.9	75.8
Nuclear	**21.1**	23.2	21.2
Hydro	**1.2**	1.4	0.8
Oil and gas	**0.3**	0.5	2.2
Average cost of fuel per net KWH generated (cents) --	**1.44**	1.38	1.39

Fuel expense increased 6.8 percent due to an increase in generation because of higher energy demands and a higher average cost of fuel due to the higher cost of coal in 2002. In 2001, fuel expense decreased 7.7 percent due to a decrease in generation because of lower energy demands and a slightly lower average cost of fuel. In 2000, fuel expense increased 10.7 percent due to an increase in generation because of higher energy demands and a slightly higher average cost of fuel.

Purchased power expense decreased $87 million (11.2 percent) in 2002 primarily due to a decrease in off-system purchases used to meet lower off-system sales commitments. This decrease, which had no significant effect on income, was partially offset by a $43 million increase in capacity expense associated with new purchased power contracts. Purchased power expense increased $175 million (29.4 percent) in 2001 primarily due to an increase in off-system purchases used to meet off-system sales commitments. These transactions had no significant effect on earnings. Purchased power expense in 2000 increased $206 million (53.0 percent) over the prior year due to higher retail energy demands and off-system purchase transactions used to meet off-system sales transactions.

In 2002, other operation and maintenance expenses increased $85 million (6.8 percent) due to increased generating plant maintenance, higher transmission expense, and increased property insurance expense. In 2001, other operation and maintenance expenses increased $41 million (3.4 percent) due to additional severance costs, increased scheduled generating plant maintenance, and higher uncollectible account expense. Other operation and maintenance expenses in 2000 increased slightly over the prior year. Increased line maintenance, customer assistance and sales expense, and severance costs were partially offset by decreased generating plant maintenance and decreased employee benefit provisions.

Depreciation and amortization decreased $197 million in 2002 primarily as a result of discontinuing accelerated depreciation, beginning amortization of the regulatory liability for accelerated cost recovery, and lowering the composite depreciation rates in January 2002 all in accordance with the retail rate order. Depreciation and amortization decreased $19 million in 2001 primarily due to lower accelerated amortization under the third year of a prior GPSC retail rate order. Depreciation and amortization increased $66 million in 2000 primarily due to $50 million of additional accelerated amortization of regulatory assets required under the second year of the prior GPSC retail rate order and increased plant in service. See Note 3 to the financial statements under "Retail Rate Orders" for additional information.

Interest expense decreased in 2002 and 2001 primarily due to lower interest rates that offset new financing costs. Interest expense increased in 2000 due to the issuance of additional senior notes. The Company refinanced or retired $929 million, $775 million, and $179 million of securities in 2002, 2001, and 2000, respectively. Interest capitalized decreased in 2002 due to the transfer of three new generation projects to Southern Power. Interest capitalized increased in 2001 and 2000 during the construction phase of these new projects. See Note 4 under "Construction Program" for additional information regarding the construction and subsequent transfer of these generation assets. Distributions on preferred securities of subsidiary companies increased in 2002 due to the issuance of additional securities and remained unchanged in 2001. Distributions on preferred securities of subsidiary companies decreased $7 million in 2000 due to the redemption of $100 million of preferred securities in December 1999.

Other income (expense), net decreased in 2002 due to lower gains realized on sales of assets. Other income (expense), net increased in 2001 due to gains realized on sales of assets and a decrease in charitable contributions. Other income (expense), net decreased in 2000 due to an increase in charitable contributions.

Effects of Inflation

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

FUTURE EARNINGS POTENTIAL

General

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

Growth in energy sales is subject to a number of factors which traditionally have included changes in contracts with neighboring utilities, energy conservation practiced by customers, the price elasticity of demand, weather, competition, initiatives to increase sales to existing customers, and the rate of economic growth in the Company's service area which has decreased recently in concert with a slowing national economy. Retail sales growth assuming normal weather is expected to be 2.3 percent on average from 2003 to 2005 and is down from last year's forecast of 3.1 percent.

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

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 $59 million in 2002. Future pension income is dependent on several factors including trust earnings and changes to the plan. Current estimates indicate a reversal of recording pension income to recording pension expense by as early as 2006. Postretirement benefit costs for the Company were $43 million in 2002 and are expected to continue to trend upward. A portion of pension and postretirement benefit costs is capitalized based on construction-related labor charges. For the Company, pension income and postretirement benefit costs are a component of the regulated rates and do not have a significant effect on net income. For additional information, see Note 2 to the financial statements.

In December 2001, the GPSC approved a three-year retail rate order for the Company ending December 31, 2004. Under the terms of the order, earnings will be evaluated annually against a retail return on common equity range of 10 percent to 12.95 percent. Two-thirds of any earnings above the 12.95 percent return will be applied to rate refunds with the remaining one-third retained by the Company. Retail rates were decreased by $118 million effective January 1, 2002. Pursuant to a previous three-year accounting order, the Company recorded $333 million of accelerated cost amortization and interest thereon which has been credited to a regulatory liability account as mandated by the GPSC. Under the rate order, the accelerated amortization and the interest will be amortized equally over three years as a credit to expense beginning in 2002. Within the three year period covered by the rate order, the Company may not file for a general base rate increase unless its projected retail return on common equity falls below 10 percent. Georgia Power is required to file a general rate case on July 1, 2004, in response to which the GPSC would be expected to determine whether the rate order should be continued, modified, or discontinued. See Note 3 to the financial statements under "Retail Rate Orders" for additional information.

Beginning in 2002, the Company entered into purchased power agreements which will result in higher capacity and operating and maintenance payments in future years. Under the current retail rate order, these costs will be reflected in rates evenly over the three years ending 2004. In December 2002, the GPSC approved additional expansion of the Company's electricity generating capacity starting in 2005 through purchased power contracts. Beginning in June 2005, the Company will purchase 1,040 megawatts of capacity from the planned units at Plant McIntosh to be built and owned by Southern Power, and will also buy 620 megawatts of capacity from a plant owned by Duke Energy Trading & Marketing. See Note 4 to the financial statements under "Purchased Power Commitments" for additional information. Additionally, the GPSC approved the retirement of 415 megawatts from 11 units at plants

Arkwright, Atkinson, and Mitchell. The retirements are the result of a unit retirement analysis that determined the units are more expensive to operate than the cost of replacement power. When property subject to composite 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.

On December 24, 2002, the GPSC approved an order allowing Georgia Power to implement a natural gas and oil procurement and hedging program effective January 1, 2003. This order allows the Company to use financial instruments in implementing a hedging program. The order limits the program in terms of time, volume, dollars, and physical amounts hedged. The costs of the program, including any net losses, are recovered as a fuel cost through the fuel cost recovery mechanism. Annual net financial gains from the hedging program will be shared with the retail customers receiving 75 percent and Georgia Power retaining 25 percent of the net gains.

Georgia Power had three generation projects under construction during 2001. They included two units at Plant Dahlberg, a ten-unit, 800 megawatt combustion turbine facility; two units totaling 1,132 megawatts at Plant Wansley; and Plant Franklin (formerly Plant Goat Rock), a two-unit, 1,181 megawatt facility. All three of these projects have been transferred, at cost, to Southern Power. The ten Dahlberg units and two Franklin units were transferred in 2001 and the transfer of the two Wansley units was completed in January 2002.

See Note 3 to the financial statements for information regarding material litigation issues that could possibly affect future earnings.

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

The State of Georgia is currently considering changes to laws that could potentially impact Georgia Power's ability to establish sites for new transmission lines. The proposed legislation would require certification by the GPSC prior to the acquisition of any property for the construction of an electric transmission line. The outcome of this matter cannot now be determined.

Proposed nuclear security legislation is expected to be introduced in the 108th Congress. The Nuclear Regulatory Commission (NRC) is also considering additional security measures for licensees that could require immediate implementation. Any such requirements could have a significant impact on the Company's nuclear power plants and result in increased operation and maintenance expenses as well as additional capital expenditures. The impact of any new requirements would depend upon the development and implementation of the regulations.

Industry Restructuring

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

This past year, merchant energy companies and traditional electric utilities with significant energy marketing and trading activities came 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 financial impact regarding its limited energy trading operations.

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

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

FERC Matters

In December 1999, the Federal Energy Regulatory Commission (FERC) issued its final rule on Regional Transmission Organizations (RTOs). The order encouraged utilities owning transmission systems to form RTOs on a voluntary basis. Southern Company has submitted a series of status reports informing the FERC of progress toward the development of a Southeastern RTO. In these status reports, Southern Company explained that it is developing a for-profit RTO known as SeTrans with a number of non-jurisdictional cooperative and public power entities. In 2002, the sponsors of SeTrans established a Stakeholder Advisory Committee, which will participate in the development of the RTO, and held public meetings to discuss the SeTrans proposal. On October 10, 2002, the FERC granted Southern Company's and other SeTrans sponsors' petition for a declaratory order regarding the governance structure and the selection process for the Independent System Administrator (ISA) of the SeTrans RTO. The FERC also provided guidance on other issues identified in the petition. The SeTrans sponsors announced the selection of ESB International, Ltd. (ESBI) to be the preferred candidate for ISA. Should negotiations with this candidate successfully conclude with final agreement among the parties, the SeTrans sponsors intend to seek any state and federal regulatory or other approvals necessary for the formation of the SeTrans RTO and the approval of ESBI to serve in the capacity of SeTrans ISA. The creation of SeTrans is not expected to have a material impact on the Company's financial statements; however, the outcome of this matter cannot now be determined.

In July 2002, the FERC issued a notice of proposed rulemaking regarding open access transmission service and standard electricity market design. The proposal, if adopted, would among other things: (1) require transmission assets of jurisdictional utilities to be operated by an independent entity; (2) establish a standard market design; (3) establish a single type of transmission service that applies to all customers; (4) assert jurisdiction over the transmission component of bundled retail service; (5) establish a generation reserve margin; (6) establish bid caps for a day ahead and spot energy markets; and (7) revise the FERC policy on the pricing of transmission expansions. Comments on certain aspects of the proposal have been submitted by Southern Company. Any impact of this proposal on the Company will depend on the form in which final rules may be ultimately adopted; however, the Company's revenues, expenses, assets, and liabilities could be adversely affected by changes in the transmission regulatory structure in its regional power market.

Accounting Policies

Critical Policy

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

New Accounting Standards

<u>Derivatives</u>

Effective January 2001, Georgia Power adopted FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended. In October 2002, the Emerging Issues Task Force (EITF) of the FASB announced accounting changes related to energy trading contracts in Issue No. 02-03. In October 2002, the Company prospectively adopted the EITF's requirements to reflect the impact of certain energy trading contracts on a net basis. This change had no material impact on the

Company's income statement. Another change also required certain energy trading contracts to be accounted for on an accrual basis effective January 2003. This change had no impact on the Company's current accounting treatment.

Asset Retirement Obligations

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

Guarantees

In 2002, the FASB issued Interpretation No. 45, Accounting and Disclosure Requirements for Guarantees. This interpretation requires disclosure of certain direct and indirect guarantees, as reflected in Note 4 to the financial statements under "Guarantees." Also, the interpretation requires recognition of a liability at inception for certain new or modified guarantees issued after December 31, 2002. The adoption of Interpretation No. 45 in January 2003 did not have a material impact on the Company's financial statements.

FINANCIAL CONDITION

Plant Additions

In 2002, gross utility plant additions were $884 million. These additions were primarily related to transmission and distribution facilities, the purchase of nuclear fuel and equipment to comply with environmental standards. The funds needed for gross property additions are currently provided from operations, short-term and long-term debt, and capital contributions from Southern Company. The Statements of Cash Flows provide additional details.

Credit Rating Risk

The Company does not have any credit agreements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are contracts that could require collateral -- but not accelerated payment -- in the event of a credit rating change to below investment grade. At December 31, 2002, the maximum potential collateral requirements were approximately $229 million.

Exposure to Market Risks

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

The weighted average interest rate on variable long-term debt outstanding at December 31, 2002 was 1.7 percent. If the Company sustained a 100 basis point change in interest rates for all variable rate long-term debt, the change would affect annualized interest expense by approximately $9 million. To further mitigate the Company's exposure to interest rates, the Company has entered into interest rate swaps that were designed as cash flow hedges of variable rate debt or anticipated debt issuances. See Note 1 and Note 9 to the financial statements under "Financial Instruments" for additional information. The Company is not aware of any facts or circumstances that would significantly affect such exposures in the near term.

To mitigate residual risks relative to movements in electricity prices, the Company entered into fixed price contracts for the purchase and sale of electricity through the wholesale electricity market and to a lesser extent similar contracts for gas purchases. Realized gains and losses are recognized in the Statements of Income as incurred. At December 31, 2002 and 2001, exposure from these activities was not material to the Company's financial statements. Fair value of changes in derivative energy contracts and year-end valuations were as follows:

	Changes in Fair Value	
	2002	2001
	(in millions)	
Contracts beginning of year	**$0.4**	$0.9
Contracts realized or settled	**0.9**	(0.6)
New contracts at inception	**-**	-
Changes in valuation techniques	**-**	-
Current period changes	**(1.2)**	0.1
Contracts end of year	**$0.1**	$0.4

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

Gains (losses) were not material and were recognized in income in 2002 and 2001. The Company is exposed to market-price risk in the event of nonperformance by parties 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 9 to the financial statements under "Financial Instruments."

Financing Activities

In 2002, the Company's financing costs decreased due to lower interest rates despite the issuance of new debt during the year. New issues during 2000 through 2002 totaled $2.6 billion and retirement or repayment of higher-cost securities totaled $1.9 billion.

The Company's current liabilities exceed current assets because of the continued use of short-term debt as a funding source to meet cash needs as well as scheduled maturities of long-term debt. Subsequent to December 31, 2002, the Company has issued $250 million of new securities with the proceeds being used primarily to retire current maturities and to reduce short-term debt. An additional $150 million of securities has been issued to retire long-term debt and for other corporate purposes.

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

Composite financing rates for long-term debt, preferred stock, and preferred securities for the years 2000 through 2002, as of year-end, were as follows:

	2002	2001	2000
Composite interest rate on long-term debt	**4.47%**	4.26%	5.90%
Composite preferred stock dividend rate	**4.60**	4.60	4.60
Composite preferred securities dividend rate	**6.35**	7.49	7.49

Liquidity and Capital Requirements

Cash provided from operating activities of $1.2 billion increased by $142 million primarily due to lower fuel inventories and the collection of underrecovered fuel costs. See the Statements of Cash Flows for additional information.

The Company plans investments primarily in additional transmission and distribution facilities and equipment to comply with environmental requirements. In addition to the funds needed for the construction program, capital will be needed for lease commitments and fuel and purchased power contracts. For additional information, see Note 4 to the financial statements.

Also, capital will be needed for the maturities of long-term debt. The Company will continue to retire higher-cost debt and preferred securities and replace these obligations with lower-cost capital if market conditions permit. For additional information, see Note 9 to the financial statements under "Securities Due Within One Year."

As a result of requirements by the NRC, the Company has established external trust funds for nuclear decommissioning costs. For additional information concerning nuclear decommissioning costs, see Note 1 to the financial statements under "Depreciation and Nuclear Decommissioning."

As discussed in Note 2, the Company also provides postretirement benefits to substantially all employees and funds trusts to the extent required by the GPSC and the FERC.

The liquidity and capital requirements discussed above are as follows:

	2003	2004	2005
	(in millions)		
Construction expenditures	$ 759	$781	$806
Senior and other notes	320	0	150
Leases			
Capital	2	2	2
Operating	30	28	23
Purchase commitments			
Fuel	1,097	764	657
Purchased power	223	285	389
Trusts			
Nuclear decommissioning	9	9	9
Postretirement benefits	8	9	8

Sources of Capital

The Company expects to meet future capital requirements primarily using funds generated from operating activities and equity funds from Southern Company and by the issuance of new debt and equity securities, term loans, and short-term borrowings. The Company received new financing authority from the GPSC in early 2002, which allows for the issuance of new long-term securities.

Recently, the Company has relied on the issuance of unsecured debt and trust preferred securities, in addition to unsecured pollution control bonds issued for its benefit by public authorities, to meet its long-term external financing requirements. To meet short-term cash needs and contingencies, the Company had approximately $1.175 billion of unused credit arrangements with banks at the beginning of 2003. See Note 9 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper and extendible commercial notes at the request and for the benefit of the Company and the other Southern Company operating companies. At December 31, 2002, the Company had outstanding $358 million of commercial paper and $19 million of extendible commercial notes.

In February 2002, the Company defeased its first mortgage bond indenture. As a result, the Company cannot issue any securities pursuant to the first mortgage bond indenture. Any liens or encumbrances on the Company's property pursuant to the first mortgage bond indenture were discharged. See "First Mortgage Bond Indenture" under Note 9 to the financial statements for more information.

At the beginning of 2003, Georgia Power had not used any of its available credit arrangements. Bank credit arrangements are as follows:

		Expires
Total	Unused	2003
(in millions)		
$1,175	$1,175	$1,175

All of these credit arrangements allow for the execution of term loans for an additional two year period.

Environmental Matters

New Source Review Enforcement Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action in U.S. District Court in Georgia. The complaint alleges violations of the New Source Review provisions of the Clean Air Act with respect to coal-fired generating facilities at the Company's Bowen and Scherer plants. The civil action requests penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. The Clean Air Act authorizes civil penalties of up to $27,500 per day, per violation at each generating unit. Prior to January 30, 1997, the penalty was $25,000 per day.

The EPA concurrently issued to the Company a notice of violation related to the two plants mentioned previously. In early 2000, the EPA filed a motion to amend its complaint to add the violations alleged in its notice of violation. The complaint and notice of violation are similar to those brought against and issued to several other electric utilities. These complaints and notices of violation allege that the utilities failed to secure necessary permits or install additional pollution control equipment when performing maintenance and construction at coal-burning plants constructed or under construction prior to 1978. As directed by the court, the EPA refiled its amended complaint limiting claims to those brought against the Company.

The case against the Company has been stayed since the spring of 2001, pending a ruling by the U.S. Court of Appeals for the Eleventh Circuit in the appeal of a very similar New Source Review enforcement action against the Tennessee Valley Authority (TVA). The TVA appeal involves many of the same legal issues raised by the actions against the Company. Because the outcome of the TVA appeal could have a significant adverse impact on Georgia Power, the Company has been a party to that case as well. On August 21, 2002, the U.S. District Court in Georgia denied the EPA's motion to reopen the Georgia case. The denial was without prejudice to the EPA to refile the motion at a later date, which the EPA has not done at this time.

The Company believes that it complied with applicable laws and the EPA's regulations and interpretations in effect at the time the work in question took place. An adverse outcome in any one of these cases could require substantial capital expenditures and additional operation and maintenance expenses 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.

Plant Wansley Clean Air Act Litigation

On December 30, 2002, the Sierra Club, Physicians for Social Responsibility, Georgia ForestWatch, and one individual filed a civil suit in the U.S. District Court in Georgia against Georgia Power for alleged violations of the Clean Air Act at Plant Wansley. The complaint alleges Clean Air Act violations at both the existing coal-fired units and the new combined cycle units. Specifically, the plaintiffs allege (1) opacity violations at the coal-fired units, (2) violations of a permit provision that requires the combined cycle units to operate above certain levels, (3) violation of the nitrogen oxide emission offset requirements, and (4) violation of the hazardous air pollutant (HAPS) requirements. The civil action requests injunctive and declaratory relief, civil penalties, a supplemental environmental project, and attorneys' fees. The Clean Air Act authorizes civil penalties of up to $27,500 per day, per violation at each generating unit. On January 27, 2003, Georgia Power filed a response to the complaint. Georgia Power also filed a motion to dismiss the allegations regarding emission offsets and HAPS. While Georgia Power believes that it has complied with applicable laws and regulations, an adverse outcome could require payment of substantial penalties. The final outcome of this matter cannot now be determined.

Environmental Statutes and Regulations

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Compliance with these environmental requirements will involve significant costs, a major portion of which is expected to be recovered through existing ratemaking provisions. There is no assurance, however, that all such costs will, in fact, be recovered.

Compliance with the federal Clean Air Act and resulting regulations has been, and will continue to be, a significant focus for the Company. The Title IV acid rain provisions of the Clean Air Act, for example, required significant reductions in sulfur dioxide and nitrogen oxide emissions. Compliance was required in two phases -- Phase I, effective in 1995 and Phase II, effective in 2000. Construction expenditures associated with Phase I and Phase II compliance totaled approximately $206 million.

Some of the expenditures required to comply with the Phase II acid rain requirements 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 Atlanta, Georgia. The State of Georgia has adopted regulations that will require additional nitrogen oxide emission reductions from plants in and/or near those nonattainment areas, beginning in May 2003. Seven generating plants in the Atlanta area will be affected. Construction expenditures for compliance with these new rules are currently estimated at approximately $690 million, of which $71 million remains to be spent.

To help bring the remaining nonattainment areas into compliance with the one-hour ozone standard, in 1998 the EPA issued regional nitrogen oxide reduction rules. Those rules required 21 states, including Georgia, to reduce and cap nitrogen oxide emissions from power plants and other large industrial sources. For Georgia, the EPA must complete a separate rulemaking before the requirements will apply. The EPA proposed a rule for Georgia in 2002 and expects to issue a final rule in 2003. The proposed rule requires compliance by May 1, 2005.

In July 1997, the EPA revised the national ambient air quality standards for ozone and particulate matter. These revisions made the standards significantly more stringent. In the subsequent litigation of these standards, the U.S.

Supreme Court found the EPA's implementation program for the new ozone standard unlawful and remanded it to the EPA for further rulemaking. The EPA is expected to propose implementation rules designed to address the court's concerns in 2003 and issue final implementation rules in 2004. The remaining legal challenges to the new standards, which were pending before the U.S. Court of Appeals, District of Columbia Circuit, have been resolved.

The EPA plans to designate areas as attainment or nonattainment with the new eight-hour ozone standard by April 2004, based on air quality data for 2001 through 2003. Several areas within the Company's service territory are likely to be designated nonattainment under the new ozone standard. State implementation plans, including new emission control regulations necessary to bring those areas into attainment, could be required as early as 2007. Those state plans could require further reductions in nitrogen oxide emissions from power plants. If so, reductions could be required sometime after 2007. The impact of any new standards will depend on the development and implementation of applicable regulations.

The EPA currently plans to designate areas as attainment or nonattainment with the new fine particulate matter standard by the end of 2004. Those area designations will be based on air quality data collected during 2001 through 2003. Several areas within the Company's service territory will likely be designated nonattainment under the new particulate matter standard. State implementation plans, including new emission control regulations necessary to bring those areas into attainment, could be required as early as the end of 2007. Those state plans will likely require reductions in sulfur dioxide emissions from power plants. If so, the reductions could be required sometime after 2007. Any additional emission reductions and costs associated with the new fine particulate matter standard cannot be determined at this time.

The EPA has also announced plans to issue a proposed Regional Transport Rule for the fine particulate matter standard by the end of 2003 and to finalize the rule in 2005. This rule would likely require year-round sulfur dioxide and nitrogen oxide emission reductions from power plants as early as 2010. If issued, this rule would likely modify other state implementation plan requirements for attainment of the fine particulate matter standard and the eight-hour ozone standard. It is not possible at this time to determine the effect such a rule would have on the Company.

Further reductions in sulfur dioxide could also be required under the EPA's Regional Haze rules. The Regional Haze rules require states to establish Best Available Retrofit Technology (BART) standards for certain sources that contribute to regional haze. The Company has a number of plants that could be subject to these rules. The EPA regional haze program calls for states to submit State Implementation Plans in 2007 and 2008 that contain emission reduction strategies for achieving progress toward the visibility improvement goal. In 2002, however, the U.S. Court of Appeals, District of Columbia Circuit, vacated and remanded the BART provisions of the federal Regional Haze rules to the EPA for further rulemaking. Because new BART rules have not been developed and state visibility assessments are only beginning, it is not possible to determine the effect of these rules on the Company at this time.

The EPA's Compliance Assurance Monitoring (CAM) regulations under Title V of the Clean Air Act require that monitoring be performed to ensure compliance with emissions limitations on an ongoing basis. The regulations require certain facilities with Title V operating permits to develop and submit a CAM plan to the appropriate permitting authority upon applying for renewal of the facility's Title V operating permit. The Company will be applying for renewal of its Title V operating permits between 2003 and 2005, and a number of its plants will likely be subject to CAM requirements for at least one pollutant, in most cases, particulate matter. The Company is in the process of developing CAM plans, which could indicate a need for improved particulate matter controls at affected facilities. Because the plans are still in the early stages of development, the Company cannot determine the extent to which improved controls could be required or the costs associated with any necessary improvements. Actual ongoing monitoring costs are expensed as incurred and are not material for any period presented.

In December 2000, having completed its utility studies for mercury and other HAPS, the EPA issued a determination that an emission control program for mercury and, perhaps, other HAPS is warranted. The program is being developed under the Maximum Achievable Control Technology provisions of the Clean Air Act. The EPA currently plans to issue proposed rules regulating mercury emissions from electric utility boilers by the end of 2003, and those regulations are scheduled to be finalized by the end of 2004. Compliance could be required as early as 2007. Because the rules have not yet been proposed, the costs associated with compliance cannot be determined at this time.

In December 2002, the EPA issued final and proposed revisions to the New Source Review program under the Clean Air Act. In February 2003, several northeastern states petitioned the D.C. Circuit Court for a stay of the final rules. The proposed rules are open to public comment and may be revised before being finalized by the EPA. If fully implemented, these proposed and final regulations could affect the applicability of the New Source Review provisions to activities at the Company's facilities. In any event, any final regulations must be adopted by the State of Georgia in order to apply to the Company's facilities. The effect of these proposed and final rules cannot be determined at this time.

Several major bills to amend the Clean Air Act to impose more stringent emissions limitations have been proposed. Three of these, the Bush Administration's Clear Skies Act, the Clean Power Act of 2002, and the Clean Air Planning Act of 2002, proposed to further limit power plant emissions of sulfur dioxide, nitrogen oxides, and mercury. The latter two bills also proposed to limit emissions of carbon dioxide. None of these bills were enacted into law in the last Congress. Similar bills have been, and are anticipated to be, introduced this year. The Bush Administration's Clear Skies Act was recently reintroduced, and President Bush has stated that it will be a high priority for the Administration. Other bills already introduced include the Climate Stewardship Act of 2003, which proposes capping greenhouse gas emissions. The cost impacts of such legislation would depend upon the specific requirements enacted.

Domestic efforts to limit greenhouse gas emissions have been spurred by international discussions surrounding the Framework Convention on Climate Change and specifically the Kyoto Protocol, which proposes international constraints on the emissions of greenhouse gases. The Bush Administration does not support U.S. ratification of the Kyoto Protocol or other mandatory carbon dioxide reduction legislation and has instead announced a new voluntary climate initiative which seeks an 18 percent reduction by 2012 in the rate of greenhouse gas emissions relative to the dollar value of the U.S. economy. As part of Southern Company, the Company is involved in a voluntary electric utility industry sector climate change initiative in partnership with the government. Because this initiative is still under development, it is not possible to determine the effect on the Company at this time.

The Company must comply with other environmental laws and regulations that cover the handling and disposal of hazardous 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. The Company expensed \$4.0 million, \$0.6 million, and \$4.0 million for cleanup and ongoing monitoring costs in 2002, 2001, and 2000, respectively. The Company may be liable for a portion or all required cleanup costs for additional sites that may require environmental remediation. Under GPSC ratemaking provisions, \$21 million has been deferred in a regulatory liability account for use in meeting future environmental remediation costs. See Note 3 to the financial statements under "Other Environmental Contingencies" for information regarding the Company's potentially responsible party status at sites in Georgia.

Under the Clean Water Act, the EPA is developing new rules aimed at reducing impingement and entrainment of fish and fish larvae at cooling water intake structures that will require numerous biological studies, and, perhaps, retrofits to some intake structures at existing power plants. The new rule was proposed in February 2002 and will be finalized by August 2004. The impact of any new standards will depend on the development and implementation of applicable regulations.

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

The EPA and state environmental regulatory agencies are reviewing and evaluating various other matters including limits on pollutant discharges to impaired waters, hazardous waste disposal requirements, and other regulatory matters. The impact of any new standards will depend on the development and implementation of applicable regulations.

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

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

The Company's 2002 Annual Report includes forward-looking statements in addition to historical information. Forward-looking information includes, among other things, statements concerning retail sales growth expectations. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "predicts," "projects," "potential" or "continue" or the negative of these terms or other comparable terminology. The Company cautions that there are various important factors that could cause actual results to differ materially from those indicated in the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include the impact of recent and future federal and state regulatory change, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry and also changes in environmental and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations; current and future litigation, including the pending EPA civil action; the effect, extent, and timing of the entry of additional competition in the markets in which the Company operates; the impact of fluctuations in commodity prices, interest rates, and customer demand; state and federal rate regulations; political, legal, and economic conditions and developments in the United States; the effects of, and changes in economic conditions in the areas in which the Company operates, including the current soft economy; internal restructuring or other restructuring options that may be pursued by the Company; potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial; the direct or indirect effects on the Company's business resulting from the terrorist incidents on September 11, 2001, or any similar such incidents or responses to such incidents; financial market conditions and the results of financing efforts; the ability of counterparties of the Company to make payments as and when due; the ability of the Company to obtain additional generating capacity at competitive prices; weather and other natural phenomena; and other factors discussed elsewhere herein and in other reports (including Form 10-K) filed from time to time by the Company with the Securities and Exchange Commission.

STATEMENTS OF INCOME
For the Years Ended December 31, 2002, 2001, and 2000
Georgia Power Company 2002 Annual Report

	2002	2001	2000
		(in thousands)	
Operating Revenues:			
Retail sales	**$4,288,097**	$4,349,312	$4,317,338
Sales for resale --			
Non-affiliates	**270,678**	366,085	297,643
Affiliates	**98,323**	99,411	96,150
Other revenues	**165,362**	150,986	159,487
Total operating revenues	**4,822,460**	4,965,794	4,870,618
Operating Expenses:			
Operation --			
Fuel	**1,002,703**	939,092	1,017,878
Purchased power --			
Non-affiliates	**264,814**	442,196	356,189
Affiliates	**419,839**	329,232	239,815
Other	**848,436**	810,043	795,458
Maintenance	**476,962**	430,413	404,189
Depreciation and amortization	**403,507**	600,631	619,094
Taxes other than income taxes	**201,857**	202,483	204,527
Total operating expenses	**3,618,118**	3,754,090	3,637,150
Operating Income	**1,204,342**	1,211,704	1,233,468
Other Income and (Expense):			
Allowance for equity funds used during construction	**7,622**	9,081	2,901
Interest income	**3,857**	4,264	2,629
Equity in earnings of unconsolidated subsidiaries	**3,714**	4,178	3,051
Interest expense, net of amounts capitalized	**(168,391)**	(183,879)	(208,868)
Distributions on preferred securities of subsidiary	**(62,553)**	(59,104)	(59,104)
Other income (expense), net	**(12,973)**	(11,897)	(53,396)
Total other income and (expense)	**(228,724)**	(237,357)	(312,787)
Earnings Before Income Taxes	**975,618**	974,347	920,681
Income taxes	**357,319**	363,599	360,587
Earnings Before Cumulative Effect of Accounting Change	**618,299**	610,748	560,094
Cumulative effect of accounting change-- less income taxes of $162	**-**	257	-
Net Income	**618,299**	611,005	560,094
Dividends on Preferred Stock	**670**	670	674
Net Income After Dividends on Preferred Stock	**$ 617,629**	$ 610,335	$ 559,420

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

BALANCE SHEETS
At December 31, 2002 and 2001
Georgia Power Company 2002 Annual Report

Assets	2002	2001
	(in thousands)	
Current Assets:		
Cash and cash equivalents	$ 16,873	$ 23,260
Receivables --		
Customer accounts receivable	302,995	271,728
Unbilled revenues	104,454	104,594
Under recovered regulatory clause revenues	117,580	161,462
Other accounts and notes receivable	122,585	129,073
Affiliated companies	40,501	87,786
Accumulated provision for uncollectible accounts	(5,825)	(8,895)
Fossil fuel stock, at average cost	120,048	202,759
Materials and supplies, at average cost	263,364	279,237
Other	96,922	125,246
Total current assets	1,179,497	1,376,250
Property, Plant, and Equipment:		
In service	17,222,661	16,886,399
Less accumulated provision for depreciation	7,333,529	7,243,209
	9,889,132	9,643,190
Nuclear fuel, at amortized cost	119,588	112,771
Construction work in progress	667,581	883,285
Total property, plant, and equipment	10,676,301	10,639,246
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	36,167	35,209
Nuclear decommissioning trusts	346,870	364,180
Other	28,612	29,618
Total other property and investments	411,649	429,007
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	524,510	543,584
Prepaid pension costs	341,944	273,405
Unamortized debt issuance expense	67,362	58,165
Unamortized premium on reacquired debt	178,590	173,724
Other	162,686	117,706
Total deferred charges and other assets	1,275,092	1,166,584
Total Assets	$13,542,539	$13,611,087

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

BALANCE SHEETS
At December 31, 2002 and 2001
Georgia Power Company 2002 Annual Report

Liabilities and Stockholder's Equity	2002	2001
	(in thousands)	
Current Liabilities:		
Securities due within one year	$ 322,125	$ 311,620
Notes payable	357,677	747,537
Accounts payable --		
Affiliated	135,260	109,591
Other	445,220	409,253
Customer deposits	94,859	83,172
Taxes accrued --		
Income taxes	20,245	35,247
Other	134,269	125,807
Interest accrued	59,608	46,942
Vacation pay accrued	42,442	41,830
Other	112,131	120,980
Total current liabilities	1,723,836	2,031,979
Long-term debt (See accompanying statements)	3,109,619	2,961,726
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	2,176,438	2,163,959
Deferred credits related to income taxes	208,410	229,216
Accumulated deferred investment tax credits	324,994	337,482
Employee benefits provisions	236,486	244,647
Other	373,740	440,774
Total deferred credits and other liabilities	3,320,068	3,416,078
Company obligated mandatorily redeemable preferred securities of subsidiary trusts holding company junior subordinated notes (See accompanying statements)	940,000	789,250
Preferred stock (See accompanying statements)	14,569	14,569
Common stockholder's equity (See accompanying statements)	4,434,447	4,397,485
Total Liabilities and Stockholder's Equity	$13,542,539	$13,611,087
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2002 and 2001
Georgia Power Company 2002 Annual Report

	2002	2001	2002	2001
	(in thousands)		*(percent of total)*	
Long-Term Debt:				
First mortgage bonds --				
Maturity / Interest Rates				
2005 / 6.07%	$ -	$ 1,860		
Total first mortgage bonds	-	1,860		
Long-term notes payable --				
Variable rate (1.98125% at 1/1/02) due February 22, 2002	-	300,000		
5.25% to 5.75% due 2003	320,000	350,000		
5.50% due December 1, 2005	150,000	150,000		
6.20% due February 1, 2006	150,000	150,000		
4.875% due July 15, 2007	300,000	-		
5.125% to 6.875% due 2011-2047	745,000	545,000		
Total long-term notes payable	1,665,000	1,495,000		
Other long-term debt --				
Pollution control revenue bonds --				
Collateralized: 6.00% to 6.25% due 2018-2019	-	7,800		
Non-collateralized:				
1.75% to 5.45% due 2012-2034	751,760	701,760		
Variable rates (1.30% to 2.50% at 1/1/03) due 2011-2032	934,130	984,130		
Total other long-term debt	1,685,890	1,693,690		
Capitalized lease obligations	81,411	83,371		
Unamortized debt premium (discount), net	(557)	(575)		
Total long-term debt (annual interest requirement -- $179.6 million)	3,431,744	3,273,346		
Less amount due within one year	322,125	311,620		
Long-term debt excluding amount due within one year	$3,109,619	$2,961,726	36.5%	36.3%
Company Obligated Mandatorily Redeemable Preferred Securities				
$25 liquidation value --				
4.875%	$ 300,000	$ -		
6.85%	200,000	200,000		
7.125%	440,000	-		
7.60%	-	175,000		
7.75%	-	414,250		
Total (annual distribution requirement -- $59.1 million)	940,000	789,250	11.1	9.6
Cumulative Preferred Stock:				
$100 stated value at 4.60%	14,569	14,569		
Total (annual dividend requirement -- $0.7 million)	14,569	14,569		
Less amount due within one year	-	-		
Total excluding amount due within one year	14,569	14,569	0.2	0.2
Common Stockholder's Equity:				
Common stock, without par value --				
Authorized - 15,000,000 shares				
Outstanding - 7,761,500 shares	344,250	344,250		
Paid-in capital	2,156,040	2,182,557		
Premium on preferred stock	40	40		
Retained earnings	1,945,520	1,870,791		
Accumulated other comprehensive income (loss)	(11,403)	(153)		
Total common stockholder's equity	4,434,447	4,397,485	52.2	53.9
Total Capitalization	$8,498,635	$8,163,030	100.0%	100.0%

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

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2002, 2001, and 2000
Georgia Power Company 2002 Annual Report

	Common Stock	Paid-In Capital	Premium on Preferred Stock	Retained Earnings	Other Comprehensive Income (loss)	Total
			(in thousands)			
Balance at December 31, 1999	$344,250	$1,815,983	$40	$1,777,937	$ -	$3,938,210
Net income after dividends on preferred stock	-	-	-	559,420	-	559,420
Capital contributions from parent company	-	301,514	-	-	-	301,514
Cash dividends on common stock	-	-	-	(549,600)	-	(549,600)
Balance at December 31, 2000	344,250	2,117,497	40	1,787,757	-	4,249,544
Net income after dividends on preferred stock	-	-	-	610,335	-	610,335
Capital distributions to parent company	-	(160,000)	-	-		(160,000)
Capital contributions from parent company	-	225,060	-	-	-	225,060
Other comprehensive income (loss)	-	-	-	-	(153)	(153)
Cash dividends on common stock	-	-	-	(527,300)	-	(527,300)
Preferred stock transactions, net	-	-	-	(1)	-	(1)
Balance at December 31, 2001	344,250	2,182,557	40	1,870,791	(153)	4,397,485
Net income after dividends on preferred stock	-	-	-	617,629	-	617,629
Capital contributions from parent company	-	173,483	-	-	-	173,483
Capital distributions to parent company	-	(200,000)	-	-	-	(200,000)
Other comprehensive income (loss)	-	-	-	-	(11,250)	(11,250)
Cash dividends on common stock	-	-	-	(542,900)	-	(542,900)
Balance at December 31, 2002	$344,250	$2,156,040	$40	$1,945,520	$(11,403)	$4,434,447

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2002, 2001, and 2000
Georgia Power Company 2002 Annual Report

	2002	2001	2000
		(in thousands)	
Net income after dividends on preferred stock	$617,629	$610,335	$559,420
Other comprehensive income (loss):			
Change in additional minimum pension liability, net of tax of $(4,853)	(7,693)	-	-
Change in fair value of marketable securities, net of tax of $(97)	153	-	-
Cumulative effect of accounting change for qualifying hedges, net of tax of $180	-	286	-
Changes in fair value of qualifying hedges, net of tax of $(2,599), $(277), respectively	(3,708)	(439)	-
Less: Reclassification adjustment for amounts included in net income	(2)	-	-
Total other comprehensive income (loss)	(11,250)	(153)	-
Comprehensive Income	$606,379	$610,182	$559,420

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

STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2002, 2001, and 2000

Georgia Power Company 2002 Annual Report

	2002	2001	2000
		(in thousands)	
Operating Activities:			
Net income	$ 618,299	$ 611,005	$ 560,094
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization	411,435	697,143	712,960
Deferred income taxes and investment tax credits, net	65,550	(48,329)	(28,961)
Pension, postretirement, and other employee benefits	(76,700)	(57,239)	(61,825)
Other, net	(38,353)	(43,458)	10,324
Changes in certain current assets and liabilities --			
Receivables, net	68,527	60,914	(108,621)
Fossil fuel stock	82,711	(103,296)	26,835
Materials and supplies	15,874	(15,628)	(9,715)
Other current assets	(18,880)	3,755	(9,282)
Accounts payable	64,902	(15,406)	64,412
Taxes accrued	(6,540)	18,392	7,334
Other current liabilities	16,166	(46,691)	(102,379)
Net cash provided from operating activities	1,202,991	1,061,162	1,061,176
Investing Activities:			
Gross property additions	(883,968)	(1,389,751)	(1,078,163)
Cost of removal net of salvage	(60,912)	(50,093)	3,247
Sales of property	387,212	534,760	-
Other	27,169	45,319	(8,697)
Net cash used for investing activities	(530,499)	(859,765)	(1,083,613)
Financing Activities:			
(Decrease) increase in notes payable, net	(389,860)	43,698	67,598
Proceeds --			
Senior notes	500,000	600,000	300,000
Pollution control bonds	-	404,535	78,725
Preferred securities	740,000	-	-
Capital contributions from parent company	173,483	225,060	301,514
Redemptions --			
First mortgage bonds	(1,860)	(390,140)	(100,000)
Pollution control bonds	(7,800)	(385,035)	(78,725)
Senior notes	(330,000)	-	-
Preferred securities	(589,250)	-	-
Preferred stock	-	-	(383)
Capital distributions to parent company	(200,000)	(160,000)	-
Payment of preferred stock dividends	(721)	(578)	(751)
Payment of common stock dividends	(542,900)	(527,300)	(549,600)
Other	(29,971)	(17,747)	(1,231)
Net cash (used for) provided from financing activities	(678,879)	(207,507)	17,147
Net Change in Cash and Cash Equivalents	(6,387)	(6,110)	(5,290)
Cash and Cash Equivalents at Beginning of Period	23,260	29,370	34,660
Cash and Cash Equivalents at End of Period	$ 16,873	$ 23,260	$ 29,370
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $9,368, $38,331, and $23,152 capitalized for 2002, 2001, and 2000, respectively)	$203,707	$234,456	$265,373
Income taxes (net of refunds)	281,661	381,995	392,310

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

The Company is a wholly owned subsidiary of Southern Company, which is the parent company of five operating companies, Southern Power Company (Southern Power), a system service company (SCS), Southern Communications Services (Southern LINC), Southern Company Gas (Southern GAS), Southern Company Holdings (Southern Holdings), Southern Nuclear Operating Company (Southern Nuclear), Southern Telecom, and other direct and indirect subsidiaries. The operating companies -- Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Savannah Electric -- provide electric service in four southeastern states. 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 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. SCS provides, at cost, specialized services to Southern Company and subsidiary companies. Southern LINC provides digital wireless communications services to the operating companies and also markets these services to the public within the Southeast. Southern Telecom provides fiber cable services within the Southeast. Southern GAS, which began operation in August 2002, is a competitive retail natural gas marketer serving communities in Georgia. Southern Holdings is an intermediate holding subsidiary for Southern Company's investments in leveraged leases, alternative fuel products, and an energy services business. Southern Nuclear provides services to Southern Company's nuclear power plants.

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

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

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at 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 operations. Costs for these services amounted to $318 million in 2002, $286 million in 2001, and $266 million in 2000. 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 the following nuclear-related services are rendered to the Company at cost: general executive and advisory services; general operations, management and technical services; administrative services including procurement, accounting, employee relations, and systems and procedures services; strategic planning and budgeting services; and other services with respect to business and operations. Costs for these services amounted to $301 million in 2002, $281 million in 2001, and $281 million in 2000.

The Company has an agreement with Southern Power under which the Company operates and maintains Southern Power owned plants Dahlberg, Franklin, and Wansley at cost. Collections from these agreements with Southern Power amounted to $5.3 million in 2002 and $1.0 million in 2001. These agreements arose from the transfer of certain generation facilities to Southern Power in 2001 and 2002. See Note 4 under "Construction Program" for additional information.

Effective June 2002, the Company entered into purchased power agreements with Southern Power for capacity and energy. Purchased power costs in 2002 amounted to $128 million. Additionally, the Company recorded $12 million of prepaid capacity expenses included in Other Deferred Charges and Other Assets on the balance sheet at December 31, 2002. See Note 4 under "Purchased Power Commitments" for additional information.

The Company has an agreement with Gulf Power under which Gulf Power jointly owns a portion of Plant Scherer. Under this agreement, Georgia Power operates Plant Scherer and Gulf Power reimburses the Company for its proportionate share of the related expenses which were $4.5 million in 2002. Georgia Power has an agreement with Savannah Electric under which Georgia Power jointly owns a portion of Plant McIntosh. Under this agreement, Savannah Electric operates Plant McIntosh and Georgia Power reimburses Savannah Electric for its proportionate share of the related expenses which were $1.8 million in 2002. See Note 6 for additional information.

The operating companies, including Georgia Power, Southern Power, and Southern GAS may 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. See Note 4 under "Fuel Commitments" and "Purchased Power Commitments" for additional information.

Regulatory Assets and Liabilities

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

	2002	2001
	(in millions)	
Deferred income tax charges	$ 525	$ 544
Deferred income tax credits	(208)	(229)
Premium on reacquired debt	179	174
Corporate building lease	54	54
Vacation pay	54	52
Postretirement benefits	25	28
Department of Energy assessments	16	18
Generating plant outage costs	48	24
Accelerated cost recovery	(222)	(336)
Environmental remediation reserve	(21)	-
Purchased power	(63)	-
Other regulatory assets	7	17
Other regulatory liabilities	(1)	(1)
Total	$ 393	$ 345

See "Depreciation and Nuclear Decommissioning" in this note for information regarding significant regulatory assets and liabilities created as a result of the January 1, 2003 adoption of FASB Statement No. 143, Accounting for Asset Retirement Obligations.

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

Revenues and Fuel Costs

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

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

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

Fuel expense includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel. Total charges for nuclear fuel included in fuel expense amounted to $71 million in 2002, $75 million in 2001, and $75 million in 2000. The Company has contracts with the U.S. Department of Energy (DOE) that provide for the permanent disposal of used nuclear fuel. The DOE failed to begin disposing of used nuclear fuel in January 1998 as required by the contracts, and the Company is pursuing legal remedies against the government for breach of contract. Sufficient pool storage capacity is available at Plant Vogtle to maintain full-core discharge capability for both units until the year 2014. To maintain pool discharge capability at Plant Hatch, effective June 2000, an on-site dry storage facility for Plant Hatch became operational. Sufficient dry storage capacity is believed to be available to continue dry storage operations at Plant Hatch through the life of the plant. Procurement of on-site dry storage capacity at Plant Vogtle will commence in sufficient time to maintain pool full-core discharge capability.

Also, the Energy Policy Act of 1992 required the establishment of a Uranium Enrichment Decontamination and Decommissioning Fund, which is to be funded in part by a special assessment on utilities with nuclear plants. The assessment will be paid over a 15-year period, which began in 1993. This fund will be used by the DOE for the decontamination and decommissioning of its nuclear fuel enrichment facilities. The law provides that utilities will recover these payments in the same manner as any other fuel expense. The Company -- based on its ownership interests -- estimates its remaining liability at December 31, 2002 under this law to be approximately $13 million. This obligation is recorded in other deferred credits in the accompanying Balance Sheets.

Depreciation and Nuclear Decommissioning

Depreciation of the original cost of depreciable utility plant in service is provided primarily by using composite straight-line rates, which approximated 2.9 percent in 2002 and 3.3 percent in 2001 and 2000. The composite depreciation rate was reduced because the lives of depreciable assets were extended effective January 2002 under the retail rate order. 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.

In January 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 cost of retiring long-lived assets. The present value of the ultimate costs for an asset's future retirement must be recorded in the period in which the liability is incurred. The cost must be capitalized as part of the related long-lived asset and depreciated over the asset's useful life.

There was no cumulative effect adjustment to net income resulting from the adoption of Statement No. 143. The Company received permission from the GPSC to defer the transition adjustment, therefore, the Company recorded a related regulatory asset of $21 million to reflect the regulatory treatment of these costs under Statement No. 71 as of January 2003. The initial Statement No. 143 liability the Company recognized was $469 million, of which $332 million was removed from the accumulated depreciation reserve. The amount capitalized to property, plant, and equipment was $116 million.

The liability recognized to retire long-lived assets primarily relates to the Company's nuclear facilities, which include the Company's ownership interests in plants Hatch and Vogtle. In addition, the Company has retirement obligations related to various landfill sites, ash ponds, and underground storage tanks. The Company has also identified retirement obligations related to certain transmission and distribution facilities, leasehold improvements, equipment on customer property, and property associated with Georgia Power rail lines. However, a liability for the removal of these facilities will not be recorded because no reasonable estimate can be made regarding the timing of any related retirements. The Company will continue to recognize in the Statements of Income the ultimate removal costs in accordance with respective regulatory treatment. Any difference between costs recognized under Statement No. 143 and those reflected in rates will be recognized as either a regulatory asset or liability. It is estimated that this annual difference will be approximately $23 million. Management believes actual asset removal costs will be recoverable in rates over time.

Statement No. 143 does not permit non-regulated companies to continue accruing future retirement costs for long-lived assets they do not have a legal obligation to retire. However, in accordance with the regulatory treatment of these costs, the Company will continue to recognize the removal costs for these other obligations in the depreciation rates. As of January 1, 2003, the amount included in the accumulated depreciation reserve that represents a regulatory liability for these costs was $419 million.

The Company recorded accelerated depreciation and amortization amounting to $91 million in 2001 and $135 million in 2000. Effective January 2002, the Company discontinued recording accelerated depreciation and amortization in accordance with the retail rate order. Also, the Company was ordered to amortize $333 million -- the cumulative balance previously expensed -- equally over three years as a credit to depreciation and amortization expense beginning January 2002. See Note 3 under "Retail Rate Orders" for additional information.

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

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

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

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

Annual provisions for nuclear decommissioning expense are based on an annuity method as approved by the GPSC. The amounts expensed in 2002 and fund balances as of December 31, 2002 were:

	Plant Hatch	Plant Vogtle
	(in millions)	
Amount expensed in 2002	$7	$2
	(in millions)	
Accumulated provisions:		
External trust funds, at fair value	$219	$128
Internal reserves	7	4
Total	$226	$132

Effective January 1, 2002, the GPSC decreased the annual provision for decommissioning expenses to $9 million. This amount is based on the NRC generic estimate to decommission the radioactive portion of the facilities as of 2000. The estimates are $383 million and $282 million for plants Hatch and Vogtle, respectively.

The ultimate costs associated with the 2000 NRC minimum funding requirements are $823 million and $1.03 billion for plants Hatch and Vogtle, respectively. Significant assumptions include an estimated inflation rate of 4.7 percent and an estimated trust earnings rate of 6.5 percent. The Company expects the GPSC to periodically review and adjust, if necessary, the amounts collected in rates for the anticipated cost of decommissioning.

In January 2002, the NRC granted the Company a 20-year extension of the licenses for both units at Plant Hatch which permits the operation of units 1 and 2 until 2034 and 2038, respectively. Decommissioning costs will not reflect the license extension until a new site study is completed in 2003 and the GPSC issues a new rate order, which is not expected until 2004.

Income Taxes

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

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

AFUDC represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, it increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation expense. Interest related to the construction of new facilities not included in the Company's retail rates is capitalized in accordance with standard interest capitalization requirements. For the years 2002, 2001, and 2000, the average AFUDC rates were 3.79 percent, 6.33 percent, and 6.74 percent, respectively. AFUDC and interest capitalized, net of taxes, as a percentage of net income after dividends on preferred stock, was less than 3.0 percent for 2002, 2001, and 2000.

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 estimated 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 certain generating plant maintenance costs. In accordance with a GPSC order, the Company defers and amortizes nuclear refueling costs over the unit's operating cycle before the next refueling. The refueling cycles range from 18 to 24 months for each unit. In accordance with the 2001 retail rate order, the Company defers the costs of certain significant inspection costs for the combustion turbines at Plant McIntosh and amortizes such costs over 10 years, which approximates the expected maintenance cycle.

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 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 reevaluated when circumstances or events change.

Cash and Cash Equivalents

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

Materials and Supplies

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

Stock Options

Southern Company provides non-qualified stock options to a large segment of the Company's employees ranging from line management to executives. The Company accounts for its stock-based compensation plans in accordance with Accounting Principles Board Opinion No. 25. Accordingly, no compensation expense has been recognized because the exercise price of all options granted equaled the fair market value on the date of grant. When options are exercised, the Company receives a capital contribution from Southern Company equivalent to the related income tax benefit.

Comprehensive Income

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

Financial Instruments

The Company uses derivative financial instruments to hedge exposures 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.

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

The Company and its affiliates, through SCS acting as their agent, enter into commodity related forward and option contracts to limit exposure to changing prices on certain fuel purchases and electricity purchases and sales. Substantially all of the Company's bulk energy purchases and sales contracts are derivatives. However, these contracts qualify as normal purchases and sales and are accounted for under the accrual method. Other contracts qualify as cash flow hedges of anticipated transactions, resulting in the deferral of related gains and losses in other comprehensive income until the hedged transactions occur. Any ineffectiveness is recognized currently in net income. Contracts that do not qualify for the normal purchase and sale exception and that do not meet the hedge requirements are marked to market through current period income and are recorded on a net basis in the Statements of Income.

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

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
At December 31, 2002	**$3,350**	**$3,417**
At December 31, 2001	$3,190	$3,190
Preferred securities:		
At December 31, 2002	**$940**	**$961**
At December 31, 2001	$789	$782

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

2. RETIREMENT BENEFITS

The Company has defined benefit, trusteed pension plans that cover substantially all employees. The Company also provides certain non-qualified benefit plans for a selected group of management and highly compensated employees. Also, the Company provides certain medical care and life insurance benefits for retired employees. The Company funds postretirement trusts to the extent required by the GPSC and the FERC. In late 2000, as well as in 2002, the Company adopted several pension and postretirement benefits plan changes that had the effect of increasing benefits to both current and future retirees.

Plan assets consist primarily of domestic and international equities, global fixed income securities, real estate, and private equity investments. The measurement date for plan assets and obligations is September 30 for each year.

Pension Plan

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

	Projected Benefit Obligation	
	2002	2001
	(in millions)	
Balance at beginning of year	$1,448	$1,322
Service cost	36	35
Interest cost	107	101
Benefits paid	(74)	(74)
Amendments	33	-
Actuarial loss	14	64
Balance at end of year	$1,564	$1,448

	Plan Assets	
	2002	2001
	(in millions)	
Balance at beginning of year	$2,044	$2,464
Actual return on plan assets	(137)	(356)
Benefits paid	(69)	(64)
Balance at end of year	$1,838	$2,044

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

	2002	2001
	(in millions)	
Funded status	$274	$ 596
Unrecognized transition obligation	(17)	(22)
Unrecognized prior service cost	123	98
Unrecognized net actuarial (loss)	(78)	(444)
Prepaid asset, net	302	228
Portion included in benefit obligations	40	45
Total prepaid assets recognized in the Balance Sheets	$342	$ 273

In 2002 and 2001, amounts recognized in the Balance Sheets for accumulated other comprehensive income and intangible assets were $13 million and $10 million and $0 and $11 million, respectively.

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

	2002	2001	2000
	(in millions)		
Service cost	$ 36	$ 35	$ 33
Interest cost	107	101	94
Expected return on plan assets	(179)	(168)	(152)
Recognized net gain	(27)	(31)	(26)
Net amortization	4	3	(1)
Net pension (income)	$ (59)	$ (60)	$ (52)

Postretirement Benefits

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

	Accumulated Benefit Obligation	
	2002	2001
	(in millions)	
Balance at beginning of year	$542	$495
Service cost	8	9
Interest cost	40	39
Benefits paid	(27)	(24)
Actuarial loss	64	23
Balance at end of year	$627	$542

	Plan Assets	
	2002	2001
	(in millions)	
Balance at beginning of year	$195	$198
Actual return on plan assets	(18)	(26)
Employer contributions	49	47
Benefits paid	(27)	(24)
Balance at end of year	$199	$195

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

	2002	2001
	(in millions)	
Funded status	$(427)	$(347)
Unrecognized transition obligation	96	105
Unrecognized prior service cost	98	104
Unrecognized net loss	106	5
Fourth quarter contributions	37	27
Accrued liability recognized in the Balance Sheets	$ (90)	$(106)

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

	2002	2001	2000
	(in millions)		
Service cost	$ 8	$ 9	$ 7
Interest cost	40	39	36
Expected return on plan assets	(20)	(19)	(16)
Net amortization	15	14	12
Net postretirement cost	$ 43	$43	$39

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

	2002	2001	2000
Discount	6.5%	7.5%	7.5%
Annual salary increase	4.0	5.0	5.0
Long-term return on plan assets	8.5	8.5	8.5

An additional assumption used in measuring the accumulated postretirement benefit obligations was a weighted average medical care cost trend rate of 8.75 percent for 2002, decreasing gradually to 5.25 percent through the year 2010 and remaining at that level thereafter. An annual increase or decrease in the assumed medical care cost trend rate of 1 percent would affect the accumulated benefit obligation and the service and interest cost components at December 31, 2002 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$59	$52
Service and interest costs	5	4

Employee Savings Plan

The Company sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides a 75 percent matching contribution up to 6 percent of an employee's base salary. Total matching contributions made to the plan for the years 2002, 2001, and 2000 were $17 million, $16 million, and $15 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. The Company's business activities are also 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 currently filed against the Company cannot be predicted at this time; however, after consultation with legal counsel, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on the Company's financial statements.

Retail Rate Orders

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

Under a previous three-year order ending December 2001, the Company's earnings were evaluated against a retail return on common equity range of 10 percent to 12.5 percent. The order further provided for $85 million in each year, plus up to $50 million of any earnings above the 12.5 percent return during the second and third years, to be applied to accelerated amortization or depreciation of assets. Two-thirds of any additional earnings above the 12.5 percent return were applied to rate refunds, with the remaining one-third retained by the Company. In 2000, the Company recorded $44 million of revenue subject to refund for estimated earnings above 12.5 percent retail return on common equity. Refunds applicable to 2000 were made to customers in 2001. Pursuant to the order, the Company recorded $333 million of accelerated amortization and interest thereon, which has been credited to a regulatory liability account as mandated by the GPSC.

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

Under GPSC ratemaking provisions, $21 million has been deferred in a regulatory liability account for use in meeting future environmental remediation costs.

Retail Fuel Hedging Program

On December 24, 2002, the GPSC approved an order, effective in January 2003, allowing Georgia Power to implement a natural gas and oil procurement and hedging program. This order allows the Company to use financial instruments in implementing a hedging program. The order limits the program in terms of time, volume, dollars, and physical amounts hedged. The costs of the program, including any net losses, are recovered as a fuel cost through the fuel cost recovery clause. Annual net financial gains from the hedging program will be shared with the retail customers receiving 75 percent and Georgia Power retaining 25 percent of the net gains.

New Source Review Enforcement Actions

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

The EPA concurrently issued to the Company a notice of violation related to the two plants mentioned previously. In early 2000, the EPA filed a motion to amend its complaint to add the violations alleged in its notice of violation. The complaint and notice of violation are similar to those brought against and issued to several other electric utilities. These complaints and notices of violation allege that the utilities failed to secure necessary permits or install additional pollution control equipment when performing maintenance and construction at coal-burning plants constructed or under construction prior to 1978. As directed by the court, the EPA refiled its amended complaint limiting claims to those brought against the Company.

The case against the Company has been stayed since the spring of 2001, pending a ruling by the U.S. Court of Appeals for the Eleventh Circuit in the appeal of a very similar New Source Review enforcement action against the Tennessee Valley Authority (TVA). The TVA appeal involves many of the same legal issues raised by the actions against the Company. Because the outcome of the TVA appeal could have a significant adverse impact on Georgia Power, the Company has been a party to that case as well. On August 21, 2002, the U.S. District Court in Georgia denied the EPA's motion to reopen the Georgia case. The denial was without prejudice to the EPA to refile the motion at a later date, which the EPA has not done at this time.

The Company believes that it complied with applicable laws and the EPA's regulations and interpretations in effect at the time the work in question took place. 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 financial condition if such costs are not recovered through regulated rates.

Plant Wansley Clean Air Act Litigation

On December 30, 2002, the Sierra Club, Physicians for Social Responsibility, Georgia ForestWatch, and one individual filed a civil suit in the U.S. District Court in Georgia against Georgia Power for alleged violations of the Clean Air Act at Plant Wansley. The complaint alleges Clean Air Act violations at both the existing coal-fired units and the new combined cycle units. Specifically, the plaintiffs allege (1) opacity violations at the coal-fired units, (2) violations of a permit provision that requires the combined cycle units to operate above certain levels, (3) violation of the nitrogen oxide emission offset requirements, and (4) violation of the hazardous air pollutant requirements. The civil action requests injunctive and declaratory relief, civil penalties, a supplemental environmental project, and attorneys' fees. The Clean Air Act authorizes civil penalties of up to $27,500 per day, per violation at each generating unit.

On January 27, 2003, Georgia Power filed a response to the complaint. Georgia Power also filed a motion to dismiss the allegations regarding emission offsets and hazardous air pollutants. While Georgia Power believes that it has complied with applicable laws and regulations, an adverse outcome could require payment of substantial penalties. The final outcome of this matter cannot now be determined.

Other Environmental Contingencies

The Company has been designated as a potentially responsible party at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation and Liability Act. Georgia Power has recognized $34 million in cumulative expenses through December 31, 2002 for the assessment and anticipated cleanup of sites on the Georgia Hazardous Sites Inventory. In addition, in 1995 the EPA designated Georgia Power and four other unrelated entities as potentially responsible parties at a site in Brunswick, Georgia that is listed on the federal National Priorities List. Georgia Power has contributed to the removal and remedial investigation and feasibility study costs for the site. Additional claims for recovery of natural resource damages at the site are anticipated. As of December 31, 2002, Georgia Power had recorded approximately $6 million in cumulative expenses associated with Georgia Power's agreed-upon share of the removal and remedial investigation and feasibility study costs for the Brunswick site.

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

Nuclear Performance Standards

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

The GPSC has approved a performance award of approximately $7.8 million for performance during the 1996-1998 period. This award was collected through the retail fuel cost recovery provision and recognized in income over a 36-month period that began in January 2000 as mandated by the GPSC.

For the period 1999-2001, the Company's performance fell within the criteria prescribed by the GPSC. The Company will therefore not receive an award or penalty for the 1999-2001 performance period.

Race Discrimination Litigation

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

In October 2001, the district court denied plaintiffs' motion for class certification. The plaintiffs filed a motion to reconsider the order denying class certification, and the court denied the plaintiffs' motion to reconsider. In December 2001, the plaintiffs filed a petition in the United States Court of Appeals for the Eleventh Circuit seeking permission to file an appeal of the October 2001 decision, and this petition was denied. After discovery was completed on the claims raised by the seven named plaintiffs, the defendants filed motions for summary judgment on all of the named plaintiff's claims. The parties await the district court's ruling on the seven motions for summary judgment. The final outcome of this matter cannot now be determined.

Right of Way Litigation

In 2002, Georgia Power was named as a defendant in several lawsuits brought by landowners regarding the installation and use of fiber optic cable over defendants' rights of way located on the landowners' property. The plaintiffs' lawsuits claim that defendants may not use or sublease to third parties some or all of the fiber optic communications lines on the rights of way that cross the plaintiffs' properties and that such actions by defendants exceed the easements or other property rights held by defendants. The plaintiffs assert claims for, among other things, trespass and unjust enrichment. The plaintiffs seek compensatory and punitive damages and injunctive relief. The Company believes that the plaintiffs' claims are without merit. An adverse outcome could result in substantial judgments; however, the final outcome of these matters cannot now be determined.

4. COMMITMENTS

Construction Program

Significant construction of transmission and distribution facilities and projects to remain in compliance with environmental requirements will continue. The Company currently estimates property additions to be approximately $759 million, $781 million, and $806 million in 2003, 2004, and 2005, respectively. The construction program is subject to periodic review and revision, and actual construction costs may vary from estimates because of numerous factors, including, but not limited to, changes in business conditions, revised load growth estimates, changes in environmental regulations, changes in existing nuclear plants to meet new regulatory requirements, increasing costs of labor, equipment, and materials, and cost of capital. At December 31, 2002, significant purchase commitments were outstanding in connection with the construction program.

Georgia Power had three generation projects under construction during 2001. They included two units at Plant Dahlberg, a ten-unit, 800 megawatt combustion turbine facility; two combined cycle units totaling 1,132 megawatts at Plant Wansley; and Plant Franklin, a two-unit, 1,181 megawatt combined cycle facility. All three of these projects have been transferred to Southern Power. The ten Dahlberg units and two Franklin units were transferred in 2001 and the transfer of the two Wansley units was completed in January 2002.

In connection with the transfer of plants Dahlberg, Franklin, and Wansley, the Company has assigned $12 million in vendor equipment contracts to Southern Power. While the Company could be obligated to assume responsibility for these contracts if Southern Power fails to meet these commitments, Southern Company has entered into limited keep-well arrangements whereby Southern Company would contribute funds to Southern Power either through loans or capital contributions in order to fund performance by Southern Power as equipment purchaser under certain contingencies. Southern Company has also guaranteed Southern Power obligations totaling $6.7 million for the Company's construction of transmission interconnection facilities to these plants.

Fuel Commitments

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement of fossil and nuclear fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Total estimated long-term fossil and nuclear fuel commitments at December 31, 2002 were as follows:

Year	Minimum Obligations
	(in millions)
2003	$1,097
2004	764
2005	657
2006	564
2007	465
2008 and beyond	1,236
Total	$4,783

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

In addition, SCS acts as agent for the five operating companies, Southern Power, and Southern GAS with regard to natural gas purchases. Natural gas purchases (in dollars) are based on various indices at the actual time of delivery; therefore, only the volume commitments are firm and disclosed in the following chart. The committed volumes, as of December 31, 2002, are as follows:

Year	Natural Gas
	(MMBtu)
2003	18,588,990
2004	17,306,665
2005	17,143,446
2006	12,785,477
2007	4,587,102
Total	70,411,680

Purchased Power Commitments

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

	2002	2001	2000
		(in millions)	
Energy	$53	$52	$57
Capacity	32	30	30
Total	$85	$82	$87

The Company has commitments regarding a portion of a 5 percent interest in Plant Vogtle owned by Municipal Electric Authority of Georgia (MEAG) that are in effect until the latter of the retirement of the plant or the latest stated maturity date of MEAG's bonds issued to finance such ownership interest. The payments for capacity are required whether or not any capacity is available. The energy cost is a function of each unit's variable operating costs. Except as noted below, the cost of such capacity and energy is included in purchased power from non-affiliates in the Company's Statements of Income. Capacity payments totaled $57 million, $59 million, and $58 million in 2002, 2001, and 2000, respectively. The current projected Plant Vogtle capacity payments are:

Year	Capacity Payments
	(in millions)
2003	$ 59
2004	57
2005	56
2006	54
2007	54
2008 and beyond	423
Total	$703

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

The Company has entered into other various long-term commitments for the purchase of electricity. Estimated total long-term capacity obligations at December 31, 2002 were as follows:

Year	Affiliated	Non-Affiliated
	(in millions)	
2003	$ 123	$ 41
2004	183	45
2005	255	78
2006	268	86
2007	268	87
2008 and beyond	1,800	564
Total	$2,897	$901

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

Operating Leases

The Company has entered into various operating leases with various terms and expiration dates. Rental expenses related to these operating leases totaled $35 million for

2002, $14 million for 2001, and $16 million for 2000. At December 31, 2002, estimated minimum rental commitments for these noncancelable operating leases were as follows:

Year	Minimum Obligations Rail Cars	Other	Total
	(in millions)		
2003	$ 14	$ 16	$ 30
2004	14	14	28
2005	12	11	23
2006	13	8	21
2007	12	8	20
2008 and beyond	67	23	90
Total	$ 132	$ 80	$ 212

In addition to the rental commitments above, the Company has obligations upon expiration of certain of the rail car leases with respect to the residual value of the leased property. These leases expire in 2004 and 2010, and the Company's maximum obligations are $13 million and $40 million, respectively. At the termination of the leases, at the Company's option, the Company may either exercise its purchase option or the property can be sold to a third party. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligation. A portion of the railcar lease obligations is shared with the joint owners of plants Scherer and Wansley. Rental expenses related to the railcar leases are fully recoverable through the fuel cost recovery clause as ordered by the GPSC.

Guarantees

Prior to 1999, a subsidiary of Southern Company originated loans to residential customers of the Company for heat pump purchases. These loans were sold to Fannie Mae with recourse for any loan with payments outstanding over 120 days. The Company is responsible for the repurchase of customers' delinquent loans. As of December 31, 2002, the outstanding loans guaranteed by the Company were $14 million and loan loss reserves of $3.4 million have been recorded.

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

As discussed earlier in this note under "Operating Leases," the Company has entered into certain residual value guarantees related to rail car leases.

5. NUCLEAR INSURANCE

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

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

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

NEIL also covers additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of between 8 to 26 weeks, with a maximum per occurrence per unit limit of $490 million.

After this deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. Georgia Power purchases the maximum limit allowed by NEIL subject to ownership limitations 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 three NEIL policies would be $40 million.

Following the terrorist attacks of September 2001, both ANI and NEIL confirmed that terrorist acts against commercial nuclear power stations would be covered under their insurance. Both companies, however, revised their policy terms on a prospective basis to include an industry aggregate for all terrorist acts. The NEIL aggregate, which applies to all claims stemming from terrorism within a 12 month duration, is $3.24 billion plus any amounts that would be available through reinsurance or indemnity from an outside source. The ANI cap is a $300 million shared industry aggregate.

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

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

6. JOINT OWNERSHIP AGREEMENTS

Except as otherwise noted, the Company has contracted to operate and maintain all jointly owned generating facilities. Georgia Power owns undivided interests in plants Vogtle, Hatch, Scherer, and Wansley in varying amounts jointly with Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia, the city of Dalton, Georgia, Florida Power & Light Company (FP&L), Jacksonville Electric Authority (JEA), and Gulf Power. Under these agreements, the Company is jointly and severally liable for third party claims related to these plants. In addition, the Company jointly owns the Rocky Mountain pumped storage hydroelectric plant with OPC who is the operator of the plant. The Company also jointly owns Plant McIntosh with Savannah Electric who operates the plant. The Company and Florida Power Corporation (FPC) jointly own a combustion turbine unit (Intercession City) operated by FPC.

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

At December 31, 2002, the Company's percentage ownership and investment (exclusive of nuclear fuel) in jointly owned facilities in commercial operation were as follows:

Facility (Type)	Company Ownership	Investment	Accumulated Depreciation
		(in millions)	
Plant Vogtle (nuclear)	45.7%	$3,267	$1,779
Plant Hatch (nuclear)	50.1	884	665
Plant Wansley (coal)	53.5	305	156
Plant Scherer (coal)			
Units 1 and 2	8.4	113	58
Unit 3	75.0	554	234
Plant McIntosh			
Common Facilities (combustion-turbine)	75.0	24	3
Rocky Mountain (pumped storage)	25.4	169	82
Intercession City (combustion-turbine)	33.3	12	1

7. LONG-TERM POWER SALES AGREEMENTS

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

The Company's capacity revenues were as follows:

Year	Revenues	Capacity
	(in millions)	(megawatts)
2002	**$34**	**102**
2001	26	102
2000	30	124

Unit power from specific generating plants is being sold to FP&L, FPC, and JEA. Under these agreements, approximately 103 megawatts of capacity is scheduled to be sold annually for periods after 2002 with a minimum of three years notice until the expiration of the contracts in 2010.

8. INCOME TAXES

At December 31, 2002, tax-related regulatory assets were $525 million and tax-related regulatory liabilities were $208 million. The assets are attributable to tax benefits flowed through to customers in prior years and to taxes applicable to capitalized interest. The liabilities are attributable to deferred taxes previously recognized at rates higher than current enacted tax law and to unamortized investment tax credits.

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

	2002	2001	2000
Total provision for income taxes:		(in millions)	
Federal:			
Current	**$261**	$352	$342
Deferred	**60**	(46)	(34)
	321	306	308
State:			
Current	**31**	61	48
Deferred	**5**	(8)	(5)
Deferred investment tax credits	**-**	5	10
Total	**$357**	$364	$361

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:

	2002	2001
	(in millions)	
Deferred tax liabilities:		
Accelerated depreciation	**$1,779**	$1,722
Property basis differences	**623**	660
Other	**309**	295
Total	**2,711**	2,677
Deferred tax assets:		
Federal effect of state deferred taxes	**90**	88
Other property basis differences	**170**	178
Other deferred costs	**214**	257
Other	**64**	40
Total	**538**	563
Net deferred tax liabilities	**2,173**	2,114
Portion included in current assets	**3**	50
Accumulated deferred income taxes in the Balance Sheets	**$2,176**	$2,164

In accordance with regulatory requirements, deferred investment tax credits are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the Statements of Income. Credits amortized in this manner amounted to $12 million in 2002 and $15 million in both 2001 and 2000. At December 31, 2002, all investment tax credits available to reduce federal income taxes payable had been utilized.

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

	2002	2001	2000
Federal statutory rate	**35%**	35%	35%
State income tax, net of federal deduction	**2**	4	4
Non-deductible book depreciation	**1**	2	2
Other	**(1)**	(4)	(2)
Effective income tax rate	**37%**	37%	39%

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

9. CAPITALIZATION

First Mortgage Bond Indenture

In 2002, the first mortgage bond indenture of Georgia Power was defeased by paying to JPMorgan Chase Bank, the Trustee, an amount representing the last outstanding obligations on the Company's first mortgage bonds. As a result of the defeasance, there are no longer any first mortgage bond liens on the Company's property and the Company no longer has to comply with the covenants and restrictions of the first mortgage bond indenture.

Preferred Securities

Statutory trusts formed by the Company, of which the Company owns all the common securities, have issued mandatorily redeemable preferred securities. The following securities are currently outstanding:

	Date of Issue	Amount	Rate	Notes	Maturity Date
		(millions)	%	(millions)	
Trust IV	2/1999	$200	6.850	$206	3/2029
Trust V	6/2002	440	7.125	454	3/2042
Trust VI	11/2002	300	4.875*	309	11/2042

* Issued at a five year initial fixed rate of 4.875 percent and, thereafter, at fixed rates determined through remarketings for specific periods of varying length or at floating rates determined by reference to 3-month LIBOR plus 3.05 percent.

The securities issued by Trusts I, II, and III were redeemed in 2002.

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

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

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

Pollution Control Bonds

The Company has incurred obligations in connection with the sale by public authorities of tax-exempt pollution control revenue bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2002 was $1.7 billion.

Senior Notes

In 2002, the Company issued a total of $500 million of unsecured senior notes. The proceeds of these issues were used to redeem higher cost long-term debt and to reduce short-term borrowing.

Bank Credit Arrangements

At the beginning of 2003, the Company had unused credit arrangements with banks totaling $1.175 billion expiring at April 18, 2003. Upon expiration, the $1.175 billion agreement provides the option of converting borrowings into a two-year term loan. The agreement contains stated borrowing rates but also allows for competitive bid loans. In addition, the agreement requires payment of commitment fees based on the unused portions of the commitments or the maintenance of compensating balances with the banks. Commitment fees are less than 1/8 of 1 percent for the Company. Compensating balances are not legally restricted from withdrawal. An annual fee is also paid to the agent bank.

The credit arrangements contain covenants that limit the level of indebtedness to capitalization to 65 percent. Not meeting these limits would result in an event of default under the credit arrangements. In addition, the credit arrangements contain cross default provisions to other indebtedness of the Company that would trigger an event of default if the Company defaulted on indebtedness over a specified threshold. The Company is currently in compliance with all such covenants.

This $1.175 billion in unused credit arrangements provides liquidity support to the Company's variable rate pollution control bonds. The amount of variable rate pollution control bonds outstanding requiring liquidity support as of December 31, 2002 was $422 million. In addition, the Company borrows under uncommitted lines of credit with banks, through a $155 million extendible commercial note program, and through a $750 million commercial paper program that has the liquidity support of the committed bank credit arrangements. The amount of extendible commercial notes and commercial paper outstanding at December 31, 2002 was $19 million and $358 million, respectively. The amount of commercial paper outstanding at December 31, 2001 was $708 million. Commercial paper is included in notes payable on the Balance Sheets.

Financial Instruments

The Company enters into interest rate swaps to hedge exposure to interest rate changes. Swaps related to fixed rate securities are accounted for as fair value hedges. Swaps related to variable rate securities or forecasted transactions are accounted for as cash flow hedges. The swaps are generally structured to mirror the terms of the hedged debt instruments; therefore, no material ineffectiveness has been recorded in earnings. The gain or loss in fair value for cash flow hedges is recorded in other comprehensive income and will be recognized in earnings over the life of the hedged items. In 2002, the Company recognized gains totaling $413 thousand upon settlement of certain cash flow hedges.

At December 31, 2002, the Company had interest rate swaps outstanding with net deferred losses as follows:

Cash Flow Hedges

Maturity	Weighted Variable Rate Received	Average Fixed Rate Paid	Notional Amount	Fair Value (Loss)
			(in millions)	
2003	*	4.76%	$250	$(7)

*Rate has not been set

Other Long-Term Debt

Assets acquired under capital leases are recorded in the Balance Sheets as utility plant in service, and the related obligations are classified as long-term debt. At December 31, 2002 and 2001, the Company had a capitalized lease obligation for its corporate headquarters building of $81 million with an interest rate of 8.1 percent. For ratemaking purposes, the GPSC has treated the lease as an operating lease and has allowed only the lease payments in cost of service. The difference between the accrued expense and the lease payments allowed for ratemaking purposes has been deferred and is being amortized to expense as ordered by the GPSC. At both December 31, 2002 and 2001, the interest and lease amortization deferred on the Balance Sheets was $54 million.

Securities Due Within One Year

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

	2002	2001
	(in millions)	
Capital lease	$ 2	$ 2
First mortgage bonds	-	2
Pollution control bonds	-	8
Senior notes	320	300
Total	$322	$312

Serial maturities through 2007 applicable to total long-term debt are as follows: $322 million in 2003; $2 million in 2004; $153 million in 2005; $153 million in 2006; and $303 million in 2007.

10. QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized quarterly financial information for 2002 and 2001 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred Stock
		(in millions)	
March 2002	**$1,007**	**$260**	**$127**
June 2002	**1,204**	**320**	**171**
September 2002	**1,517**	**498**	**271**
December 2002	**1,095**	**126**	**49**
March 2001	$1,108	$249	$108
June 2001	1,259	322	163
September 2001	1,579	515	298
December 2001	1,020	126	41

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

SELECTED FINANCIAL AND OPERATING DATA 1998-2002
Georgia Power Company 2002 Annual Report

	2002	2001	2000	1999	1998
Operating Revenues (in thousands)	**$4,822,460**	$4,965,794	$4,870,618	$4,456,675	$4,738,253
Net Income after Dividends on Preferred Stock (in thousands)	**$617,629**	$610,335	$559,420	$541,383	$570,228
Cash Dividends on Common Stock (in thousands)	**$542,900**	$527,300	$549,600	$543,000	$536,600
Return on Average Common Equity (percent)	**13.99**	14.12	13.66	14.02	14.61
Total Assets (in thousands)	**$13,542,539**	$13,611,087	$13,133,609	$12,361,860	$12,033,618
Gross Property Additions (in thousands)	**$883,968**	$1,389,751	$1,078,163	$790,464	$499,053
Capitalization (in thousands):					
Common stock equity	**$4,434,447**	$4,397,485	$4,249,544	$3,938,210	$3,784,172
Preferred stock	**14,569**	14,569	14,569	14,952	15,527
Company obligated mandatorily redeemable preferred securities	**940,000**	789,250	789,250	789,250	689,250
Long-term debt	**3,109,619**	2,961,726	3,041,939	2,688,358	2,744,362
Total (excluding amounts due within one year)	**$8,498,635**	$8,163,030	$8,095,302	$7,430,770	$7,233,311
Capitalization Ratios (percent):					
Common stock equity	**52.2**	53.9	52.5	53.0	52.3
Preferred stock	**0.2**	0.2	0.2	0.2	0.2
Company obligated mandatorily redeemable preferred securities	**11.1**	9.6	9.7	10.6	9.5
Long-term debt	**36.5**	36.3	37.6	36.2	38.0
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Security Ratings:					
First Mortgage Bonds -					
Moody's	**N/A**	A1	A1	A1	A1
Standard and Poor's	**N/A**	A	A	A+	A+
Fitch	**N/A**	AA-	AA-	AA-	AA-
Preferred Stock -					
Moody's	**Baa1**	Baa1	a2	a2	a2
Standard and Poor's	**BBB+**	BBB+	BBB+	A-	A
Fitch	**A**	A	A	A+	A+
Unsecured Long-Term Debt -					
Moody's	**A2**	A2	A2	A2	A2
Standard and Poor's	**A**	A	A	A	A
Fitch	**A+**	A+	A+	A+	A+
Customers (year-end):					
Residential	**1,734,430**	1,698,407	1,669,566	1,632,450	1,596,488
Commercial	**250,993**	244,674	237,977	229,524	221,180
Industrial	**8,240**	8,046	8,533	8,958	9,485
Other	**3,328**	3,239	3,159	3,060	3,034
Total	**1,996,991**	1,954,366	1,919,235	1,873,992	1,830,187
Employees (year-end):	**8,837**	9,048	8,860	8,961	8,371

N/A = Not Applicable.

SELECTED FINANCIAL AND OPERATING DATA 1998-2002 (continued)
Georgia Power Company 2002 Annual Report

	2002	2001	2000	1999	1998
Operating Revenues (in thousands):					
Residential	**$ 1,600,438**	$1,507,031	$ 1,535,684	$ 1,410,099	$ 1,486,699
Commercial	**1,631,130**	1,682,918	1,620,466	1,527,880	1,591,363
Industrial	**1,004,288**	1,106,420	1,154,789	1,143,001	1,170,881
Other	**52,241**	52,943	6,399	(30,892)	49,274
Total retail	**4,288,097**	4,349,312	4,317,338	4,050,088	4,298,217
Sales for resale - non-affiliates	**270,678**	366,085	297,643	210,104	259,234
Sales for resale - affiliates	**98,323**	99,411	96,150	76,426	81,606
Total revenues from sales of electricity	**4,657,098**	4,814,808	4,711,131	4,336,618	4,639,057
Other revenues	**165,362**	150,986	159,487	120,057	99,196
Total	**$4,822,460**	$4,965,794	$4,870,618	$4,456,675	$4,738,253
Kilowatt-Hour Sales (in thousands):					
Residential	**22,144,559**	20,119,080	20,693,481	19,404,709	19,481,486
Commercial	**26,954,922**	26,493,255	25,628,402	23,715,485	22,861,391
Industrial	**25,739,785**	25,349,477	27,543,265	27,300,355	27,283,147
Other	**593,202**	583,007	568,906	551,451	543,462
Total retail	**75,432,468**	72,544,819	74,434,054	70,972,000	70,169,486
Sales for resale - non-affiliates	**8,069,375**	8,110,096	6,463,723	5,060,931	6,438,891
Sales for resale - affiliates	**3,962,559**	3,133,485	2,435,106	1,795,243	2,038,400
Total	**87,464,402**	83,788,400	83,332,883	77,828,174	78,646,777
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**7.23**	7.49	7.42	7.27	7.63
Commercial	**6.05**	6.35	6.32	6.44	6.96
Industrial	**3.90**	4.36	4.19	4.19	4.29
Total retail	**5.68**	6.00	5.80	5.71	6.13
Sales for resale	**3.07**	4.14	4.43	4.18	4.02
Total sales	**5.32**	5.75	5.65	5.57	5.90
Residential Average Annual Kilowatt-Hour Use Per Customer	**12,867**	11,933	12,520	12,006	12,314
Residential Average Annual Revenue Per Customer	**$929.90**	$893.84	$929.11	$872.48	$939.73
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**14,059**	14,474	15,114	14,474	14,437
Maximum Peak-Hour Demand (megawatts):					
Winter	**11,873**	11,977	12,014	11,568	11,959
Summer	**14,597**	14,294	14,930	14,575	13,923
Annual Load Factor (percent)	**60.4**	61.7	61.6	58.9	58.7
Plant Availability (percent):					
Fossil-steam	**80.9**	88.5	86.1	84.3	86.0
Nuclear	**88.8**	94.4	91.5	89.3	91.6
Source of Energy Supply (percent):					
Coal	**59.5**	58.5	62.3	63.0	62.3
Nuclear	**16.2**	18.1	17.4	18.0	18.3
Hydro	**0.9**	1.1	0.7	0.9	2.2
Oil and gas	**0.3**	0.4	1.8	1.6	2.2
Purchased power -					
From non-affiliates	**6.3**	7.8	8.1	6.6	6.5
From affiliates	**16.8**	14.1	9.7	9.9	8.5
Total	**100.0**	100.0	100.0	100.0	100.0

DIRECTORS AND OFFICERS
Georgia Power Company 2002 Annual Report

Directors

Juanita P. Baranco
Executive Vice President
Baranco Automotive Group

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

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

L. G. Hardman III
Chairman of the Board
nBank.Corp

G. Joseph Prendergast
Retired

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

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

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

Carl Ware
Executive Vice President
The Coca-Cola Company

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

Officers

David M. Ratcliffe
President and Chief
Executive Officer

William C. Archer, III
Executive Vice President
External Affairs

Judy M. Anderson
Senior Vice President
Charitable Giving

Ronnie L. Bates
Senior Vice President
Planning, Sales and Service

M. A. Brown
Senior Vice President
Distribution

James K. Davis
Senior Vice President
Employee/Corporate Relations

Allen L. Leverett
Executive Vice President, Treasurer and
Chief Financial Officer

Leslie R. Sibert
Vice President
Transmission

Chris C. Womack
Senior Vice President
Fossil and Hydro Power

W. Craig Barrs
Vice President
Community and Economic Development

Rebecca A. Blalock
Vice President
Information Resources

Robert L. Boyer
Vice President
Power Generation

A. Bryan Fletcher
Vice President
Region Distribution

J. Kevin Fletcher
Vice President
Marketing and Customer Service

O. Ben Harris
Vice President
Land

W. Ron Hinson
Vice President, Comptroller and
Chief Accounting Officer

Chris M. Hobson
Vice President
Environmental Affairs

Ed F. Holcombe
Vice President
Governmental and Regulatory Affairs

Richard L. Holmes
Vice President
Corporate Services

E. Lamont Houston
Vice President
Region Distribution

Anne H. Kaiser
Vice President
Sales

Ellen N. Lindemann
Vice President
Human Resources

Frank J. McCloskey
Vice President
Diversity and Workplace Ethics

James E. Sykes, Jr.
Vice President
Region Distribution

J. L. Wallace
Vice President
Planning and Pricing

Janice G. Wolfe
Corporate Secretary and
Assistant Comptroller

Wayne Boston
Assistant Secretary and
Assistant Treasurer

CORPORATE INFORMATION

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

Profile
The Company produces and delivers electricity as an integrated utility to both retail and wholesale customers within the State of Georgia. The Company sells electricity to some 2.0 million customers within its service area of approximately 57,000 square miles. In 2002, retail energy sales accounted for 86 percent of the Company's total sales of 87.5 billion kilowatt-hours.

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

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

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

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

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