GEORGIA POWER
A SOUTHERN COMPANY

July 28, 2006

Docket Nos.: 50-321 50-424
50-366 50-425
72-36

NL-06-1486

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
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 2005.

2. A set of quarterly financial statements for the period ending June 30, 2006.

3. A one year projected Cash Flows Statement for period January 1, 2007, through December 31, 2007.

Should you have any questions in connection with our response, please contact me at (404) 506-7952 or Jan Miller at (404) 506-6690. This letter contains no NRC commitments.

Sincerely,

Robert A. Aubuchon

Enclosures

M004

cc: Southern Nuclear Operating Company
Mr. J. T. Gasser, Executive Vice President
Mr. L. M. Stinson, Vice President, Plant Hatch
Mr. D. E. Grissette, Vice President, Plant Vogtle
Mr. D. R. Madison, General Manager – Plant Hatch
Mr. T. E. Tynan, General Manager – Plant Vogtle
RType: CHA02.004; CVC7000

U. S. Nuclear Regulatory Commission
Dr. W. D. Travers, Regional Administrator
Mr. C. Gratton, NRR Project Manager – Hatch
Mr. C. Gratton, NRR Project Manager – Vogtle
Mr. D. S. Simpkins, Senior Resident Inspector – Hatch
Mr. G. J. McCoy, Senior Resident Inspector – Vogtle

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2006	2005	2006	2005
OPERATING REVENUES:				
Retail sales	$1,420,762	$1,227,087	$2,687,718	$2,412,323
Sales for resale--				
Non-affiliates	132,557	126,000	265,921	238,852
Affiliates	85,674	54,743	120,616	80,374
Other revenues	59,745	51,358	111,932	98,069
Total operating revenues	1,698,738	1,459,188	3,186,187	2,829,618
OPERATING EXPENSES:				
Operation--				
Fuel	556,691	412,050	991,465	721,316
Purchased power--				
Non-affiliates	82,321	64,523	138,876	117,497
Affiliates	145,518	140,800	336,037	360,804
Other	226,256	223,471	444,976	425,550
Maintenance	119,876	123,575	239,176	240,225
Depreciation and amortization	117,590	124,999	235,447	248,099
Taxes other than income taxes	68,945	58,648	136,090	119,407
Total operating expenses	1,317,197	1,148,066	2,522,067	2,232,898
OPERATING INCOME	381,541	311,122	664,120	596,720
OTHER INCOME (EXPENSE):				
Allowance for equity funds used during construction	6,338	7,935	12,123	17,192
Interest income	199	31	515	502
Interest expense, net of amounts capitalized	(61,322)	(55,174)	(121,529)	(105,594)
Interest expense to affiliate trusts	(14,877)	(14,877)	(29,755)	(29,755)
Other income (expense), net	3,370	2,821	2,376	(21)
Total other income and (expense)	(66,292)	(59,264)	(136,270)	(117,676)
EARNINGS BEFORE INCOME TAXES	315,249	251,858	527,850	479,044
Income taxes	119,059	94,140	199,003	178,794
NET INCOME	196,190	157,718	328,847	300,250
DIVIDENDS ON PREFERRED STOCK	-	167	1,010	335
NET INCOME AFTER DIVIDENDS ON PREFERRED STOCK	$196,190	$157,551	$327,837	$299,915

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, 2006	At June 30, 2005
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$11,422	$9,294
Receivables --		
Customer accounts receivable	416,118	361,605
Unbilled revenues	176,184	168,392
Under recovered regulatory clause revenue	372,587	153,301
Other accounts and notes receivable	85,136	185,223
Affiliated companies	55,814	31,350
Accumulated provision for uncollectible accounts	(8,521)	(6,575)
Fossil fuel stock, at average cost	262,620	207,959
Materials and supplies, at average cost	352,866	286,446
Other	174,706	91,819
Total Current Assets	1,898,932	1,488,814
PROPERTY, PLANT AND EQUIPMENT:		
In service	19,957,393	19,327,416
Less accumulated provision for depreciation	7,775,166	7,392,744
	12,182,227	11,934,672
Nuclear fuel, at amortized cost	148,604	129,567
Construction work in progress	599,874	443,904
Total Property, Plant and Equipment	12,930,705	12,508,143
OTHER PROPERTY AND INVESTMENTS:		
Equity investments in unconsolidated subsidiaries	68,470	65,949
Nuclear decommissioning trusts	499,868	466,656
Other	70,800	64,472
Total Other Property and Investments	639,138	597,077
DEFERRED CHARGES AND OTHER ASSETS:		
Deferred charges related to income taxes	497,775	506,259
Prepaid pension costs	487,462	460,865
Unamortized debt issuance expense	84,515	88,638
Unamortized loss on reacquired debt	165,650	172,961
Deferred under recovered regulatory clause revenues	477,611	362,692
Other	255,106	170,698
Total Deferred Charges and Other Assets	1,968,119	1,762,113
TOTAL ASSETS	$17,436,894	$16,356,147

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

	At June 30, 2006	At June 30, 2005
LIABILITIES AND STOCKHOLDER'S EQUITY		
CURRENT LIABILITIES:		
Securities due within one year	$2,822	$402,603
Notes payable	657,559	379,902
Accounts payable --		
Affiliated companies	207,585	157,765
Other	292,313	248,786
Customer deposits	140,292	122,446
Taxes accrued		
Income taxes	313,302	183,985
Other	146,254	115,596
Interest accrued	74,533	78,595
Vacation pay accrued	45,692	44,179
Other	210,770	186,640
Total Current Liabilities	2,091,122	1,920,497
LONG-TERM DEBT	4,177,916	3,931,825
LONG-TERM DEBT PAYABLE TO AFFILIATED TRUSTS	969,073	969,073
DEFERRED CREDITS AND OTHER LIABILITIES:		
Accumulated deferred income taxes	2,693,006	2,598,783
Deferred credits related to income taxes	153,196	164,588
Accumulated deferred investment tax credits	281,581	293,872
Employee benefits provisions	379,656	346,916
Asset retirement obligations	647,003	520,298
Other	548,023	581,077
Total Deferred Credits and Other Liabilities	4,702,465	4,505,534
PREFERRED STOCK	-	14,609
COMMON STOCKHOLDER'S EQUITY:		
Common stock	344,250	344,250
Paid-in capital	2,880,563	2,589,121
Retained earnings	2,288,285	2,124,641
Accumulated other comprehensive income	(16,780)	(43,403)
Total Common Stockholder's Equity	5,496,318	5,014,609
TOTAL LIABILITIES AND STOCKHOLDER'S EQUITY	$17,436,894	$16,356,147

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

	FOR THE SIX MONTHS ENDED JUNE	
	2006	2005
OPERATING ACTIVITIES:		
Net income	$328,847	$300,250
Adjustments to reconcile net income to net cash provided by operating activities --		
Depreciation and amortization	276,048	292,447
Deferred income taxes and investment tax credits, net	13,433	89,724
Deferred expenses - affiliated	18,717	20,302
Allowance for funds used during construction	(12,123)	(17,192)
Pension, postretirement, and other employee benefits	(1,225)	5,318
Stock option expense	4,330	-
Other, net	8,729	(1,058)
Changes in certain current assets and liabilities --		
Receivables, net	(89,773)	(247,991)
Fossil fuel stock	(80,881)	(23,692)
Materials and supplies	(28,885)	(16,024)
Other current assets	49,999	14,055
Accounts payable	(128,890)	(59,236)
Taxes accrued	38,209	43,098
Other current liabilities	(76,833)	(42,595)
NET CASH PROVIDED FROM OPERATING ACTIVITIES	319,702	357,406
INVESTING ACTIVITIES:		
Gross property additions	(448,857)	(381,191)
Nuclear decommissioning trust fund purchases	(241,021)	(205,261)
Nuclear decommissioning trust fund sales	234,141	196,562
Cost of removal net of salvage	(10,658)	(10,359)
Other	(9,099)	(33,274)
NET CASH USED FOR INVESTING ACTIVITIES	(475,494)	(433,523)
FINANCING ACTIVITIES:		
Increase (decrease) in notes payable, net	389,817	171,669
Proceeds --		
Senior notes	-	375,000
Pollution control bonds	10,125	185,000
Capital contributions from parent company	232,328	100,000
Gross excess tax benefit of stock options	611	-
Redemptions --		
Pollution control bonds	(10,125)	(85,000)
Senior notes	(150,000)	(300,000)
Preferred stock	(14,569)	
Special deposits - redemption funds	-	(100,000)
Payment of preferred stock dividends	(12)	(211)
Payment of common stock dividends	(301,250)	(278,050)
Other	(347)	(16,494)
NET CASH PROVIDED FROM FINANCING ACTIVITIES	156,578	51,914
NET CHANGE IN CASH AND CASH EQUIVALENTS	786	(24,203)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	10,636	33,497
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$11,422	$9,294

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

GEORGIA POWER COMPANY
PROJECTED STATEMENT OF CASH FLOWS
2007 FORECAST
(Stated in Thousands of Dollars)

	2007 FORECAST
OPERATING ACTIVITIES	
Net income before preferred dividends	$831,346
Principal noncash items-	
Depreciation and amortization	622,394
Deferred income taxes, net	(26,943)
Allowance for equity funds used during construction	(71,263)
Pension, postretirement and other employee benefits	(16,032)
Other, net	230,590
Change in current assets & liabilities-	
Receivables	(36,755)
Inventories	10,331
Accounts payable	9,114
Other current assets and liabilities	95,611
NET CASH PROVIDED FROM OPERATING ACTIVITIES	1,648,393
INVESTING ACTIVITIES	
Gross property additions	(1,485,481)
Cost of removal, net of salvage	(34,695)
Allowance for equity funds used during construction	71,263
Other property and investments	(6,514)
NET CASH USED FOR INVESTING ACTIVITIES	(1,455,427)
FINANCING ACTIVITIES	
Increase in notes payable, net	(8,860)
Proceeds -	
Senior notes	675,000
Preferred stock	300,000
Capital contributions from parent company	126,619
Redemptions -	
Senior notes	(300,000)
Trust preferred securities	(300,000)
Capitalized leases	(2,550)
Stock Option Expense	12,399
Payment of preferred stock dividends	(3,370)
Payment of common stock dividends	(678,100)
Other	(13,702)
NET CASH USED FOR FINANCING ACTIVITIES	(192,564)
NET INC (DEC) IN CASH AND TEMPORARY CASH INVESTMENTS	$402
CASH AND TEMPORARY CASH INVESTMENTS AT BEG OF PERIOD	$15,750
CASH AND TEMPORARY CASH INVESTMENTS AT END OF PERIOD	$16,152

2005 *Annual Report*

GEORGIA POWER COMPANY

GEORGIA POWER

A SOUTHERN COMPANY

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Georgia Power Company 2005 Annual Report

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SUMMARY

	2005	2004	Percent Change
Financial Highlights *(in millions):*			
Operating revenues	**$6,634**	$5,371	23.5
Operating expenses	**$5,246**	$4,112	27.6
Net income after dividends on preferred stock	**$715**	$658	8.7
Operating Data:			
Kilowatt-hour sales *(in millions):*			
Retail	**78,982**	77,904	1.4
Sales for resale - non-affiliates	**11,235**	5,970	88.2
Sales for resale - affiliates	**4,855**	4,783	1.5
Total	**95,072**	88,657	7.2
Customers served at year-end *(in thousands)*	**2,115**	2,078	1.8
Peak-hour demand *(in megawatts)*	**15,953**	15,180	5.1
Capitalization Ratios *(percent):*			
Common stock equity	**50.3**	51.0	
Preferred stock	**-**	0.2	
Long-term debt payable to affiliated trusts	**9.4**	10.1	
Long-term debt	**40.3**	38.7	
Return on Average Common Equity *(percent)*	**14.15**	13.95	
Ratio of Earnings to Fixed Charges *(times)*	**4.92**	5.11	

LETTER TO INVESTORS

Georgia Power 2005 Annual Report

Georgia Power employees' extraordinary response after Hurricane Katrina and other storms hit the Gulf Coast last year is just one of the highlights in what was a remarkable year for the company.

Whether we're responding to storms in our own back yard or to the needs of fellow Southern Company employees and customers, it's extensive pre-planning and excellent execution that makes us so successful – it really is what we do best.

That's why we were honored when the Edison Electric Institute recognized us with its Emergency Assistance Award for the outstanding assistance we provided other utilities recovering last year from hurricanes Katrina, Rita and Wilma.

Our financial results mirror our operational success. With operating revenues of $6.6 billion, Georgia Power's 2005 earnings totaled $715 million, a $57 million, or 8.7 percent, increase from 2004. We earned a 14.15 percent total company return on average common equity during 2005. Georgia Power had net plant in service of $12.0 billion at the end of 2005, with total assets of $17.0 billion.

In 2005, we announced plans to merge one of our sister companies into Georgia Power; we made significant progress on the environmental front; and we overhauled our organizational structure to bring us even closer to our customers.

Late last year, the boards of directors of Southern Company, Savannah Electric and Georgia Power approved a plan to merge Savannah Electric into Georgia Power. This move should result in operational efficiencies and cost savings for Georgia Power.

Savannah Electric customers also are expected to benefit from Georgia Power's more diverse and cost-efficient generating fleet. We anticipate completing the merger by July 2006.

We continued our efforts last year to reduce the environmental impact of our operations by:

- Turning on selective catalytic reduction systems at plants Bowen, Hammond and Wansley. This is expected to reduce the company's emissions of nitrogen oxides and, therefore, its contribution to metro Atlanta's ozone from 15 percent to 6 percent.

- Filing applications for four more scrubbers – two for Plant Wansley and two additional scrubbers for Plant Bowen. Two scrubbers are already under construction at Plant Bowen. Not only will the scrubbers, which remove sulfur dioxide (SO_2) from power plant emissions, reduce SO_2 emissions on each of these generating units by as much as 95 percent, but they also will reduce emissions of fine particulates and mercury. This is important because the Environmental Protection Agency issued its first mercury rule last year requiring significant reductions in mercury emissions from power plants.

- Working closely with DeKalb County in metro Atlanta, which approved the development of a landfill gas generation plant and a 10-year contract to sell the energy to Georgia Power for our voluntary Green Energy program.

In the past 10 years, we have invested $1 billion in environmental controls, and we'll continue to invest in environmental improvement technologies. In fact, over the next five years, Georgia Power's additional environmental investment is expected to total at least $2.4 billion.

In 2005, we also implemented a new organizational structure that moves key company leaders closer to our customers, employees and the communities we serve. We now have officer positions in major cities around the state, including Athens, Augusta, Columbus, Macon, Rome, Valdosta and, following the merger, Savannah.

Our new structure allows us to enhance efficiencies and operate consistently around the state while providing multiple cross-company leadership development opportunities within Southern Company – a key priority as we work to further develop the diversity and strength of our management ranks.

We believe improving diversity in every facet of our business is, simply put, good for business. That's why last year, for example, we launched a Hispanic Resources Web site, a one-stop shop for information to assist Spanish-speaking customers.

After all our hard work, it's nice to be recognized for our success. *Profiles in Diversity Journal* named Georgia Power to its top-10 list of diversity innovation award winners. We also were one of the Fortune 500 companies recognized as the nation's "Best Workplaces for Commuters," in large part because of SmartRide, our company commuter program that has become more popular than ever because of rising fuel prices. *Site Selection* magazine also recognized us as one of the best company's in North America for economic development.

We're especially proud of our linemen, who really shined at the International Lineman's Rodeo last year in Kansas City, winning first place in the overall, overall apprentice, investor-owned utility and senior divisions, along with a handful of individual event awards.

Continued economic vitality in Georgia helped boost electricity sales and was a key contributor to our strong financial results last year. Businesses and individuals were drawn to the state, increasing the number of customers Georgia Power serves to 2.1 million in 2005, a 1.8 percent increase from the previous year. Our retail sales of electricity climbed 1.4 percent in 2005.

It's clear to me that the work our employees do day in and day out and their commitment to the company are what make us successful – they are our greatest asset.

The changes we made and initiatives we launched last year will help ensure that we continue doing what's best for our employees, customers and communities – that we live up to our motto of being a "Citizen Wherever We Serve" – as we work to meet the state's growing demand for energy.

Sincerely,

Michael D. Garrett
April 17, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Georgia Power Company:

We have audited the accompanying balance sheets and statements of capitalization of Georgia Power Company (the "Company") (a wholly owned subsidiary of Southern Company) as of December 31, 2005 and 2004, 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, 2005. 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 the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements (pages 25 to 57) present fairly, in all material respects, the financial position of Georgia Power Company at December 31, 2005 and 2004, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
February 27, 2006

OVERVIEW

Business Activities

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

Many factors affect the opportunities, challenges, and risks of the Company's primary business of selling electricity. These factors include the ability to maintain a stable regulatory environment, to achieve energy sales growth while containing costs, and to recover rising costs. These costs include those related to growing demand, increasingly stringent environmental standards, and fuel prices. In December 2004, the Company completed a major retail rate proceeding that is expected to provide earnings stability (2004 Retail Rate Plan). This regulatory action also enables the recovery of substantial capital investments to facilitate the continued reliability of the transmission and distribution network and continued environmental improvements at the generating plants. Appropriately balancing environmental expenditures with customer prices will continue to challenge the Company for the foreseeable future. The Company expects further rate proceedings in 2006 to address fuel cost recovery due to higher than expected fuel costs for coal and natural gas.

On December 13, 2005, the Company and Savannah Electric and Power Company (Savannah Electric) entered into a merger agreement, under which Savannah Electric will merge into the Company, with the Company continuing as the surviving corporation (the Merger). The Merger must be approved by Savannah Electric's preferred shareholders and is subject to receipt of certain regulatory approvals from the Federal Energy Regulatory Commission (FERC), the Georgia Public Service Commission (PSC), and the Federal Communications Commission. Pending regulatory approvals, the Merger is expected to be completed by July 2006. See FUTURE EARNINGS POTENTIAL – "Merger" and Note 3 to the financial statements under "Retail Regulatory Matters – Merger" for additional information.

Key Performance Indicators

In striving to maximize shareholder value while providing low-cost energy to more than two million customers, the Company continues to focus on several key indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income. The Company's financial success is directly tied to the satisfaction of its customers. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance, expected weather conditions, and expected capital expenditures. Net income is the primary component of the Company's contribution to Southern Company's earnings per share goal.

The Company's 2005 results compared to its targets for some of these indicators are reflected in the following chart.

Key Performance Indicator	2005 Target Performance	**2005 Actual Performance**
Customer Satisfaction	Top quartile in customer surveys	**Top quartile**
Peak Season EFOR	2.75% or less	**1.42%**
Net Income	$678 million	**$715 million**

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The strong financial performance achieved in 2005 reflects the focus that management places on these indicators, as well as the commitment shown by the employees in achieving or exceeding management's expectations.

Earnings

The Company's 2005 earnings totaled $715 million representing a $57 million (8.7 percent) increase over 2004. Operating income increased in 2005 due to higher base retail revenues resulting from the retail rate increase

effective January 1, 2005 and more favorable weather, as well as higher wholesale revenues resulting from new contracts effective January 1, 2005, partially offset by increased non-fuel operating expenses. The Company's 2004 earnings totaled $658 million representing a $27 million (4.3 percent) increase over 2003. Operating income increased in 2004 due to higher base retail revenues attributable to more favorable weather and customer growth during the year, partially offset by higher non-fuel operating expenses. In addition, lower depreciation and amortization expense resulting from a Georgia PSC three-year retail rate plan approved in 2001 (2001 Retail Rate Plan) significantly offset increased purchased power capacity expenses. The Company's 2003 earnings totaled $631 million, representing a $13 million (2.1 percent) increase over 2002 despite lower base retail revenues resulting from the extremely mild summer weather. Higher wholesale revenues and lower non-fuel operating expenses contributed to the 2003 increase.

RESULTS OF OPERATIONS

A condensed income statement for the Company is as follows:

	Amount	Increase (Decrease) From Prior Year		
	2005	**2005**	2004	2003
		(in millions)		
Operating revenues	**$6,634**	**$1,263**	$457	$ 92
Fuel	**1,831**	**598**	128	101
Purchased power	**1,170**	**194**	200	92
Other operation and maintenance	**1,481**	**81**	153	(78)
Depreciation and amortization	**504**	**229**	(74)	(54)
Taxes other than income taxes	**260**	**32**	15	11
Total operating expenses	**5,246**	**1,134**	422	72
Operating income	**1,388**	**129**	35	20
Total other income and (expense)	**(241)**	**(20)**	5	2
Income taxes	**431**	**52**	13	9
Net income	**716**	**57**	27	13
Dividends on preferred stock	**1**	**-**	-	-
Net income after dividends on preferred stock	**$ 715**	**$ 57**	$ 27	$ 13

Revenues

Operating revenues in 2005, 2004, and 2003 and the percent of change from the prior year are as follows:

	Amount		
	2005	2004	2003
		(in millions)	
Retail – prior year	**$4,777**	$4,310	$4,288
Change in -			
Base rates	**195**	-	-
Sales growth	**135**	151	30
Weather	**21**	32	(66)
Fuel cost recovery and other	**515**	284	58
Retail – current year	**$5,643**	4,777	4,310
Sales for resale -			
Non-affiliates	**519**	247	260
Affiliates	**265**	166	175
Total sales for resale	**784**	413	435
Other operating revenues	**207**	181	169
Total operating revenues	**$6,634**	$5,371	$4,914
Percent change	**23.5%**	9.3%	1.9%

Retail base revenues of $3.6 billion in 2005 increased by $351 million (10.9 percent) from 2004 primarily due to the retail rate increase effective January 1, 2005, sustained economic strength, customer growth, more favorable weather, and generally higher prices to large business customers. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information. Retail base revenues of $3.2 billion in 2004 increased by $183 million (6.0 percent) from 2003 primarily due to an improved economy, customer growth, generally higher prices to the Company's large business customers, and more favorable weather. Retail base revenues of $3 billion in 2003 decreased by $36 million (1.2 percent) from 2002 primarily due to extremely mild summer temperatures and the sluggish economy.

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. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information.

Wholesale revenues from sales to non-affiliated utilities were:

	2005	2004	2003
		(in millions)	
Unit power sales --			
Capacity	$ 33	$ 31	$ 34
Energy	31	33	31
Other power sales --			
Capacity and other	155	75	93
Energy	300	108	102
Total	$519	$247	$260

Revenues from unit power sales contracts remained relatively constant in 2005 and 2004. Revenues from unit power sales contracts decreased slightly in 2003 due to decreased energy sales. Revenues from other non-affiliated sales increased $272 million (148.6 percent) in 2005 and decreased $12 million (6.2 percent) and $8 million (3.9 percent) in 2004 and 2003, respectively. The increase in 2005 is due to new contracts with thirty electric membership corporation customers that went into effect in January 2005 which increased the demand for energy. The capacity component of these transactions increased $73.2 million in 2005 over 2004.

Revenues from sales to affiliated companies within the Southern Company electric system, as well as purchases of energy, will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliated sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the FERC. In 2005, kilowatt-hour (KWH) energy sales to affiliates increased 1.5 percent due to higher demand, while the increase in associated revenues was 59.4 percent due to higher fuel prices. In 2004, KWH energy sales to affiliates decreased 18.2 percent due to lower demand. However, the decline in associated revenues was only 4.9 percent due to higher fuel prices. In 2003, KWH energy sales to affiliates increased 47.5 percent due to the combination of increased demand by Southern Power to meet contractual obligations and the availability of power due to milder-than-normal weather in the Company's service territory. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost.

Other operating revenues increased $25.7 million (14.2 percent) in 2005 from 2004 primarily due to higher transmission revenues of $16 million related to work performed for the other owners of the integrated transmission system in the State of Georgia and higher revenues under the open access tariff agreement, higher outdoor lighting revenues of $5.4 million, and higher customer fees that went into effect in January 2005 of $5.9 million. Other operating revenues increased $11.7 million (6.9 percent) in 2004 over 2003 primarily due to higher revenues from outdoor lighting of $4.2 million and pole attachment rentals of $4.9 million and higher gains on sales of emission allowances of $2 million. Other operating revenues increased $4 million (2.4 percent) in 2003 from the prior year primarily due to an increase in the open access transmission tariff rate, which increased revenues $7 million, and higher revenues from increased customer demand for outdoor lighting services of $4 million, partially offset by lower revenues from the rental of electric property of $4 million.

Energy Sales

KWH sales for 2005 and the percent change by year were as follows:

	KWH	Percent Change		
	2005	2005	2004	2003
	(in billions)			
Residential	23.6	2.9%	5.3%	(1.7)%
Commercial	29.8	6.3	4.0	(0.1)
Industrial	25.0	(5.0)	2.5	(0.1)
Other	0.6	(0.1)	1.1	0.4
Total retail	79.0	1.4	3.8	(0.5)
Sales for resale -				
Non-affiliates	11.2	88.2	(32.5)	9.5
Affiliates	4.9	1.5	(18.2)	47.5
Total sales for resale	16.1	49.6	(26.8)	22.0
Total sales	95.1	7.2	(1.2)	2.6

Residential KWH sales increased 2.9 percent in 2005 over 2004 due to more favorable weather, customer growth of 1.7 percent, and a 1.1 percent increase in the average energy consumption per customer. Commercial KWH sales increased 6.3 percent due to more favorable weather, sustained economic strength, customer growth of 1.8 percent, and a reclassification of customers from industrial to commercial to be consistent with the rate structure approved by the Georgia PSC when compared

to 2004. Industrial sales decreased 5.0 percent primarily due to this reclassification of customers.

Residential KWH sales increased 5.3 percent in 2004 from 2003 due to more favorable weather and a 1.9 percent increase in residential customers. Commercial KWH sales increased 4.0 percent in 2004 due to an improved economy and a 2.8 percent increase in commercial customers. Industrial sales increased 2.5 percent in 2004 due to the improved economy.

Residential KWH sales decreased 1.7 percent in 2003 from 2002 due to the effect of the milder summer weather, despite the 2.0 percent increase in residential customers. Commercial KWH sales in 2003 declined slightly due to the milder summer weather, while industrial KWH sales declined slightly due to the sluggish economy. Average retail sales growth assuming normal weather is expected to be 2.1 percent from 2006 to 2010.

Fuel and Purchased Power 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 generating units. The amount and sources of generation, the average cost of fuel per net KWH generated, and the average cost of purchased power per net KWH were as follows:

	2005	2004	2003
Total generation (billions of KWH)	**80.5**	71.5	73.1
Sources of generation (percent) --			
Coal	**75.3**	75.4	75.4
Nuclear	**18.6**	22.5	21.6
Hydro	**2.4**	2.0	2.7
Oil and gas	**3.7**	0.1	0.3
Average cost of fuel per net KWH generated (cents) --	**2.04**	1.55	1.46
Average cost of purchased power per net KWH (cents) --	**7.25**	5.17	4.03

Fuel expense increased 48.5 percent in 2005 from the prior year primarily due to an increase in the average cost of fuel, particularly natural gas, and a 12.3 percent increase in generation to meet higher demand. Fuel expense increased 11.6 percent in 2004 over 2003 primarily due to an increase in the average cost of coal and natural gas. Fuel expense increased 10.1 percent in 2003 over 2002 due to an increase in generation of 3.9 percent because of higher wholesale energy demands and a 2.8 percent higher average cost of fuel due to the higher prices of coal and natural gas in 2003.

Purchased power expense increased $194 million (19.9 percent) in 2005, $200 million (25.9 percent) in 2004, and $92 million (13.3 percent) in 2003. These increases are primarily the result of new purchased power agreements (PPAs) between the Company and Southern Power that went into effect in each of 2004, 2003, and 2002. Additional capacity expenses associated with these PPAs were $30 million, $65 million, and $75 million in 2005, 2004, and 2003, respectively. The increases in purchased power expenses also reflect the impact of the significant increases in fuel costs discussed previously.

A significant upward trend in the cost of coal and natural gas has emerged since 2003, and volatility in these markets is expected to continue. Increased coal prices have been influenced by a worldwide increase in demand as a result of rapid economic growth in China as well as by increases in mining costs. Higher natural gas prices in the United States are the result of increased demand and slightly lower gas supplies despite increased drilling activity. Natural gas supply interruptions, such as those caused by the 2005 and 2004 hurricanes, result in an immediate market response; however, the long-term impact of this price volatility may be reduced by imports of natural gas and liquefied natural gas. Fuel expenses generally do not affect net income, since they are offset by fuel revenues under the Company's fuel cost recovery provisions.

Other Operating Expenses

In 2005, other operations and maintenance expenses increased $81 million (5.8 percent). Maintenance for generating plant and transmission and distribution increased $23.5 million and $13.9 million, respectively, as a result of scheduled outages and, to a lesser extent, certain flexible projects planned for other periods. Increased employee benefit expense of $18.4 million related to pension and medical benefits and higher property insurance costs of $5.3 million resulting from storm damage also contributed to the increase. Customer

assistance expense and uncollectible account expense also increased an additional $9.3 million in 2005 over 2004, primarily as a result of promotional expenses related to an energy efficiency program and an increased number of customer bankruptcies, respectively. In 2004, other operations and maintenance expenses increased $153 million (12.3 percent) due to the timing of generating plant maintenance of $39 million and transmission and distribution maintenance of $39 million. Increased employee benefit expense of $30 million related to pension and medical benefits and higher workers compensation expense of $8 million also contributed to the increase. In 2003, other operations and maintenance expenses decreased $78 million (5.9 percent) due to the timing of generating plant maintenance of $46 million and transmission and distribution maintenance of $8 million and lower severance costs of $8 million.

Depreciation and amortization increased $229 million (83 percent) in 2005 over 2004 primarily due to the expiration at the end of 2004 of certain provisions of the Company's 2001 Retail Rate Plan. In accordance with the 2001 Retail Rate Plan, the Company amortized an accelerated cost recovery liability as a credit to amortization expense and recognized new Georgia PSC-certified purchased power costs in rates evenly over the three years ended December 31, 2004. This treatment resulted in a credit to amortization expense of $187.1 million in 2004 and a total decrease in depreciation and amortization of $74 million and $54 million in 2004 and 2003, respectively. See Note 3 to the financial statements under "Retail Regulatory Matters -- Rate Plans" for additional information.

Taxes other than income taxes increased $32 million (14.1 percent) primarily due to higher municipal gross receipts taxes of $18.1 million resulting from increased operating revenues and higher property taxes of $14.0 million. Taxes other than income taxes increased $15 million (7.0 percent) in 2004 due to higher municipal gross receipts taxes associated with increased operating revenues. Taxes other than income taxes increased $11 million (5.4 percent) in 2003 due mainly to a favorable true-up of state property tax valuations in 2002.

Other Income and (Expense)

Allowance for equity funds used during construction remained relatively constant in 2005 and increased $15.9 million in 2004, primarily due to the construction of the McIntosh combined cycle Units 10 and 11 which were placed in service in June 2005.

Interest income remained relatively constant in 2005. Interest income decreased $9 million in 2004 and increased $12 million in 2003 when compared to the prior year primarily due to interest on a favorable income tax settlement of $14.5 million in 2003.

Interest expense increased $38.8 million (21.3 percent) in 2005 from 2004 primarily due to the issuance of additional senior notes in 2005 and generally higher interest rates on variable rate debt and commercial paper. Interest expense remained relatively constant in 2004. Interest expense increased in 2003 primarily due to an increase in senior notes outstanding that was partially offset by a reduction in short-term debt outstanding. The Company refinanced or retired $635 million, $400 million, and $665 million of securities in 2005, 2004, and 2003, respectively. Interest capitalized increased in 2005 and 2004 due to the Plant McIntosh construction referenced above and decreased in 2003 due to the transfer of a project to Southern Power in 2002.

Other income and (expense), net increased $17.1 million in 2005 from 2004 primarily due to $14.2 million of additional gas hedge gains. Other income and (expense), net decreased in 2004 primarily due to the $13 million disallowance of Plant McIntosh construction costs in December 2004, partially offset by a $7.5 million decrease in donations and $3.4 million in increased income from a customer pricing program. See Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Hedging Program" and "Plant McIntosh Construction Project" for additional information.

Effects of Inflation

The Company is subject to rate regulation that is based on the recovery of historical costs. In addition, the income tax laws are based on historical costs. Therefore, inflation creates an economic loss because the Company is recovering its costs of investments in dollars that have less purchasing power. While the inflation rate has been relatively low in recent years, it continues to have an adverse effect on the Company because of the large investment in utility plant with long economic lives. Conventional accounting for historical cost does not recognize this economic loss nor the partially offsetting gain that arises through financing facilities with fixed-

money obligations such as long-term debt, preferred stock, and preferred securities. Any recognition of inflation by regulatory authorities is reflected in the rate of return allowed in the Company's approved electric rates.

FUTURE EARNINGS POTENTIAL

General

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

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability of the Company to maintain a stable regulatory environment that continues to allow for the recovery of all prudently incurred costs. Future earnings in the near term will depend, in part, upon growth in energy sales, which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth in the Company's service area.

Environmental Matters

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S District Court for the Northern District of Georgia against the Company and Alabama Power, alleging that the Company and Alabama Power had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws with respect to certain coal-fired generating facilities. Through subsequent amendments and other legal proceedings, the EPA added Savannah Electric as a defendant to the original action and filed a separate action against Alabama Power after it was dismissed from the original action. In these lawsuits, the EPA alleges that NSR violations occurred at eight coal-fired generating facilities, including the Company's Plants Bowen and Scherer. The civil action requests penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. On June 3, 2005, the U.S. District for the Northern District of Alabama issued a decision in favor of Alabama Power on two primary legal issues in the case; however, the decision does not resolve the case, nor does it address other legal issues associated with the EPA's allegations. In accordance with a separate court order, Alabama Power and the EPA are currently participating in mediation with respect to the EPA's claims. The action against the Company and Savannah Electric has been administratively closed since the spring of 2001, and none of the parties has sought to reopen the case. See Note 3 to the financial statements under "Environmental Matters - New Source Review Actions."

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $32,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in this matter could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

In December 2002 and October 2003, the EPA issued final revisions to its NSR regulations under the Clean Air Act. A coalition of states and environmental organizations filed petitions for review of these regulations. On June 24, 2005, the U.S. Court of Appeals for the District of Columbia Circuit upheld, in part, the EPA's December 2002 revisions to its NSR regulations, which included changes to the regulatory exclusions and

methods of calculating emissions increases. However, the court vacated portions of those revisions, including those addressing the exclusion of certain pollution control projects. The October 2003 revisions, which clarified the scope of the existing Routine Maintenance, Repair and Replacement exclusion, have been stayed by the Court of Appeals pending its review of the rules. On October 20, 2005, the EPA also published a proposed rule clarifying the test for determining when an emissions increase subject to the NSR requirements has occurred. The impact of these revisions and proposed rules will depend on adoption of the final rules by the EPA and the State of Georgia's implementation of such rules, as well as the outcome of any additional legal challenges, and, therefore, cannot be determined at this time.

Carbon Dioxide Litigation

In July 2004, attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed a complaint in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. A nearly identical complaint was filed by three environmental groups in the same court. The complaints allege that the companies' emissions of carbon dioxide, a greenhouse gas, contribute to global warming, which the plaintiffs assert is a public nuisance. Under common law public and private nuisance theories, the plaintiffs seek a judicial order (1) holding each defendant jointly and severally liable for creating, contributing to, and/or maintaining global warming and (2) requiring each of the defendants to cap its emissions of carbon dioxide and then reduce those emissions by a specified percentage each year for at least a decade. Plaintiffs have not, however, requested that damages be awarded in connection with their claims. Southern Company believes these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2005, the U.S. District Court for the Southern District of New York granted Southern Company's and the other defendants' motions to dismiss these cases. The plaintiffs filed an appeal to the U.S. Court of Appeals for the Second Circuit on October 19, 2005. The ultimate outcome of these matters cannot be determined at this time.

Plant Wansley Environmental Litigation

In December 2002, the Sierra Club, Physicians for Social Responsibility, Georgia Forestwatch, and one individual filed a civil suit in the U.S. District Court for the Northern District of Georgia against the Company for alleged violations of the Clean Air Act at four of the units at Plant Wansley. 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. The liability phase of the case has concluded with the court ruling in favor of the Company in part and the plaintiffs in part. In March 2005, the U.S. Court of Appeals for the Eleventh Circuit accepted the Company's petition for review of the district court's order, and oral arguments were held on January 24, 2006. The district court case has been administratively closed pending that appeal. If necessary, the district court will hold a separate trial which will address civil penalties and possible injunctive relief requested by the plaintiffs. The ultimate outcome of this matter cannot currently be determined; however, an adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require the payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

Environmental Statutes and Regulations

General

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. Applicable statutes 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 these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2005, the Company had invested approximately $1.2 billion in

capital projects to comply with these requirements, with annual costs of $117.4 million, $47.4 million, and $105.7 million for 2005, 2004, and 2003, respectively. Over the next decade, the Company expects that capital expenditures could exceed an additional $3.3 billion to assure compliance with existing and new regulations, including $410 million, $674.6 million, and $515.8 million for 2006, 2007, and 2008, respectively. Because the Company's compliance strategy is impacted by changes to existing environmental laws and regulations, the cost, availability, and existing inventory of emission allowances, and the Company's fuel mix, the ultimate outcome cannot be determined at this time. Environmental costs that are known and estimable at this time are included in capital expenditures discussed under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein.

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

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Through 2005, the Company had spent approximately $787.9 million in reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions and in monitoring emissions pursuant to the Clean Air Act. Additional controls have been announced and are currently being installed at several plants to further reduce SO_2 and NO_x emissions, maintain compliance with existing regulations, and to meet new requirements.

Approximately $699.8 million of these expenditures are related to reducing NO_x emissions pursuant to state and federal requirements in connection with the EPA's one-hour ozone standard and the 1998 regional NO_x reduction rules. Although the State of Georgia was originally included in the states subject to the regional NO_x rules, the EPA, in August 2005, stayed compliance with these requirements and initiated rulemakings to address issues raised in a petition for reconsideration filed by a coalition of Georgia industries. The impact of the 1998 regional NO_x reduction rules for Georgia will depend on the outcome of the petition for reconsideration and/or any subsequent development and approval of the State of Georgia's state implementation plan.

In 2005, the EPA revoked the one-hour ozone standard and published the final set of rules for implementation of the new, more stringent eight-hour ozone standard. Areas within the Company's service area that have been designated as nonattainment under the eight-hour ozone standard include Macon (Georgia) and a 20-county area within metropolitan Atlanta. State implementation plans, including new emission control regulations necessary to bring those areas into attainment are required for most areas by June 2007. These state implementation plans could require further reductions in NO_x emissions from power plants.

During 2005, the EPA's fine particulate matter "nonattainment" designations became effective for several areas within the Company's service area in Georgia, and the EPA proposed a rule for the implementation of the fine particulate matter standard. The EPA plans to finalize the proposed implementation rule in 2006. State plans for addressing the nonattainment designations are required by April 2008 and could require further reductions in SO_2 and NO_x emissions from power plants. The EPA has also published proposed revisions to lower the level of particulate matter currently allowed.

The EPA issued the final Clean Air Interstate Rule on March 10, 2005. This cap-and-trade rule addresses power plant SO_2 and NO_x emissions that were found to contribute to nonattainment of the eight-hour ozone and fine particulate matter standards in downwind states. Twenty-eight eastern states, including the State of Georgia, are subject to the requirements of the rule. The rule calls for additional reductions of NO_x and/or SO_2 to be achieved in two phases, 2009/2010 and 2015. These reductions will be accomplished by the installation of additional emission controls at the Company's coal-fired facilities or by the purchase of emission allowances from a cap-and-trade program.

The Clean Air Visibility Rule (formerly called the Regional Haze Rule) was finalized on July 6, 2005. The goal of this rule is to restore natural visibility conditions in certain areas (primarily national parks

and wilderness areas) by 2064. The rule involves the application of Best Available Retrofit Technology (BART) requirements and a review each decade, beginning in 2018, of progress toward the goal. BART requires that sources that contribute to visibility impairment implement additional emission reductions, if necessary, to make progress toward remedying current visibility concerns. For power plants, the Clean Air Visibility Rule allows states to determine that the Clean Air Interstate Rule satisfies BART requirements for SO_2 and NO_x. However, additional requirements could be imposed. By December 17, 2007, states must submit implementation plans that contain emission reduction strategies for implementing BART requirements and for achieving sufficient and reasonable progress toward the goal.

On March 15, 2005, the EPA announced the final Clean Air Mercury Rule, a cap-and-trade program for the reduction of mercury emissions from coal-fired power plants. The rule sets caps on mercury emissions to be implemented in two phases, 2010 and 2018, and provides for an emission allowance trading market. The Company anticipates that emission controls installed to achieve compliance with the Clean Air Interstate Rule and the eight-hour ozone and fine-particulate standards will also result in mercury emission reductions. However, the long-term capability of emission control equipment to reduce mercury emissions is still being evaluated, and the installation of additional control technologies may be required.

The impacts of the eight-hour ozone standard, the fine particulate matter nonattainment designations, the Clean Air Interstate Rule, the Clean Air Visibility Rule, and the Clear Air Mercury Rule on the Company, will depend on the development and implementation of rules at the state level. States implementing the Clean Air Mercury Rule and the Clear Air Interstate Rule, in particular, have the option not to participate in the national cap-and-trade programs and could require reductions greater than those mandated by the federal rules. Such impacts will also depend on resolution of pending legal challenges to the Clean Air Interstate Rule, the Clean Air Mercury Rule and a related petition from the State of North Carolina under section 126 of the Clean Air Act, also related to the interstate transport of air pollutants. Therefore, the full impacts of these regulations on the Company cannot be determined at this time. The Company has developed and continually updates a comprehensive environmental compliance strategy to comply with the continuing and new environmental requirements discussed above. As part of this strategy, the Company plans to install additional SO_2, NO_x, and mercury emission controls within the next several years to assure continued compliance with applicable air quality requirements.

Water Quality

In July 2004, the EPA published final rules under the Clean Water Act for the purpose of reducing impingement and entrainment of fish and fish larvae at power plants' cooling water intake structures. The new rules require baseline biological information and, perhaps, installation of fish protection technology near some intake structures at existing power plants.

The Company is installing cooling towers at additional facilities under the Clean Water Act to cool water prior to discharge. Near Atlanta, a cooling tower for one plant was completed in 2004 and two others are scheduled for completion in 2008. The total estimated cost of these projects is $173 million, with $85 million remaining to be spent. The Company is also conducting a study of the aquatic environment at another facility to determine if further thermal controls are necessary at that plant.

The full impact of these new rules will depend on the results of studies and analyses performed as part of the rules' implementation and the actual requirements established by the State of Georgia, and therefore, cannot be determined at this time

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and release 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 and monitor known sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Remediation" for additional information.

Under Georgia PSC ratemaking provisions, $22 million has been deferred in a regulatory liability account related to certain environmental insurance settlements. Under the 2004 Retail Rate Plan, this regulatory liability is being amortized as a credit to expense over a three-year period that began January 1, 2005. However, the Georgia PSC also approved an annual environmental accrual of $5.4 million. Environmental remediation expenditures are being charged against the resulting reserve as they are incurred. The annual accrual amount will be reviewed and adjusted in future regulatory proceedings.

Global Climate Issues

Domestic efforts to limit greenhouse gas emissions have been spurred by international discussions surrounding the Framework Convention on Climate Change, and specifically the Kyoto Protocol -- which proposes constraints on the emissions of greenhouse gases for a group of industrialized countries. The Bush Administration has not supported U.S. ratification of the Kyoto Protocol or other mandatory carbon dioxide reduction legislation; however, in 2002, it did announce a goal to reduce the greenhouse gas intensity of the U.S. – the ratio of greenhouse gas emissions to the value of U.S. economic output -- by 18 percent by 2012. A year later, the Department of Energy (DOE) announced the Climate VISION program to support this goal. Energy-intensive industries, including electricity generation, are the initial focus of this program. Southern Company is involved in the development of a voluntary electric utility sector climate change initiative in partnership with the government. In a memorandum of understanding signed in December 2004 with the DOE under Climate VISION, the utility sector pledged to reduce its greenhouse gas emissions rate by 3 percent to 5 percent by 2010-2012. The Company is continuing to evaluate future energy and emissions profiles relative to the Climate VISION program and is analyzing voluntary programs to support the industry initiative.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates at market-based prices. The Company also has FERC authority to make short-term opportunity sales at market rates. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in that proceeding. In February 2005, Southern Company submitted responsive information. In February 2006, the FERC suspended the proceeding. Any new market-based rate transactions in its retail service territory entered into after February 27, 2005 are subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. The impact of such sales through December 31, 2005 is not expected to exceed $4.9 million. The refund period covers 15 months. In the event that the FERC's default mitigation measures for entities that are found to have market power are ultimately applied, the Company may be required to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates. The final outcome of this matter will depend on the form in which the final methodology for assessing generation market power and mitigation rules may be ultimately adopted and cannot be determined at this time.

In addition, in May 2005, the FERC started an investigation to determine whether Southern Company satisfies the other three parts of the FERC's market-based rate analysis: transmission market power, barriers to entry, and affiliate abuse or reciprocal dealing. The FERC established a new refund period related to this expanded investigation. Any and all new market-based rate transactions both inside and outside Southern Company's retail service territory involving any Southern Company subsidiary, including the Company, will be subject to refund to the extent the FERC orders lower rates as a result of this new investigation, with the 15-month refund period beginning July 19, 2005. The impact of such sales through December 31, 2005 is not expected to exceed $10.9 million, of which $3.2 million relates to sales inside the retail service territory as discussed above. The FERC also directed that this expanded proceeding be held in abeyance pending the outcome of the proceeding on the IIC discussed below.

The Company believes that there is no meritorious basis for this proceeding and is vigorously defending itself in this matter. However, the final outcome of this

matter, including any remedies to be applied in the event of an adverse ruling in this proceeding, cannot now be determined.

Intercompany Interchange Contract

The Company's generation fleet in its retail service territory is operated under the IIC, as approved by the FERC. In May 2005, the FERC also initiated a new proceeding to examine (1) the provisions of the IIC among Alabama Power, the Company, Gulf Power, Mississippi Power, Savannah Electric, Southern Power, and Southern Company Services, Inc., as agent, under the terms of which the power pool of Southern Company is operated, and, in particular, the propriety of the continued inclusion of Southern Power as a party to the IIC, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining Southern Power as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of Southern Power, the FERC authorized Southern Power's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct. The FERC order directs that the administrative law judge who presided over the McIntosh PPA proceeding discussed herein under "PSC Matters – Plant McIntosh Construction Project", be assigned to preside over the hearing in this proceeding and that the testimony and exhibits presented in that proceeding be preserved to the extent appropriate. Hearings are scheduled for September 2006. Effective July 19, 2005, revenues from transactions under the IIC involving any Southern Company subsidiaries, including the Company, are subject to refund to the extent the FERC orders any changes to the IIC.

The Company believes that there is no meritorious basis for this proceeding and is vigorously defending itself in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in this proceeding, cannot now be determined.

Generation Interconnection Agreements

In July 2003, the FERC issued its final rule on the standardization of generation interconnection agreements and procedures (Order 2003). Order 2003 shifts much of the financial burden of new transmission investment from the generator to the transmission provider. The FERC has indicated that Order 2003, which was effective January 20, 2004, is to be applied prospectively to interconnection agreements. Subsidiaries of Tenaska, Inc., as counterparties to three previously executed interconnection agreements with subsidiaries of Southern Company, including the Company, have filed complaints at the FERC requesting that the FERC modify the agreements and that the Company refund a total of $7.9 million previously paid for interconnection facilities, with interest. The Company has opposed all such requests, and the proceedings are still pending. The impact of Order 2003 and its subsequent rehearings on the Company and the final results of these matters cannot be determined at this time.

Transmission

In December 1999, the FERC issued its final rule on Regional Transmission Organizations (RTOs). Since that time, there have been a number of additional proceedings at the FERC designed to encourage further voluntary formation of RTOs or to mandate their formation. However, at the current time, there are no active proceedings that would require the Company to participate in an RTO. Current FERC efforts that may potentially change the regulatory and/or operational structure of transmission include rules related to the standardization of generation interconnection, as well as an inquiry into, among other things, market power by vertically integrated utilities. See "Generation Interconnection Agreements" and "Market-Based Rate Authority" herein for additional information. The final outcome of these proceedings cannot now be determined. However, the Company's financial condition, results of operations, and cash flows could be adversely affected by future changes in the federal regulatory or operational structure of transmission.

PSC Matters

Merger

In connection with the Merger, the Company and Savannah Electric plan to establish a coastal regional organization for the Company that will be operating following completion of the Merger. Management expects that current Savannah Electric employees will fill most of the positions in the new regional organization.

While the Georgia PSC does not have specific approval authority over the merger of electric utilities, in January 2006, the Company and Savannah Electric filed an application with the Georgia PSC for certain approvals necessary to complete the Merger. In particular, the Company and Savannah Electric are seeking the approval of the Georgia PSC with respect to the following matters:

- the transfer of Savannah Electric's generating facilities and certification of the generating facilities as the Company's assets;
- amendments to the Company's Integrated Resource Plan to add the current Savannah Electric's customers and generating facilities;
- the transfer of Savannah Electric's assigned service territory to the Company;
- adoption of the Company's service rules and regulations to the current Savannah Electric customers;
- new fuel rate and base rate schedules that would apply to the Company's sale of electricity to the current Savannah Electric customers;
- adoption of a "merger transition adjustment" rate that would be used to more closely align Savannah Electric's existing base rates to those of the Company and a "merger transition credit" rate that would credit the additional revenues collected from former Savannah Electric customers to the Company's existing customers; and
- the issuance of additional shares of the Company's common stock to Southern Company in exchange for Southern Company's shares of Savannah Electric common stock.

The Company has also requested the Georgia PSC to better align the rates for Savannah Electric's customers with those of the Company. Currently, Savannah Electric customers pay slightly lower base rates and significantly higher fuel rates than the Company's customers. The overall effect is that Savannah Electric customers pay substantially higher overall costs for electricity. See "Fuel Cost Recovery" herein for additional information.

Rate Plans

In December 2004, the Georgia PSC approved the 2004 Retail Rate Plan for the three-year period ending December 31, 2007. Under the terms of the 2004 Retail Rate Plan, earnings are being evaluated annually against a retail return on common equity (ROE) range of 10.25 percent to 12.25 percent. Two-thirds of any earnings above 12.25 percent will be applied to rate refunds, with the remaining one-third retained by the Company. Retail rates were increased by approximately $194 million and customer fees were increased by approximately $9 million effective January 1, 2005 to cover the higher costs of purchased power; operation and maintenance expenses; environmental compliance; and continued investment in new generation, transmission and distribution facilities to support growth and ensure reliability. In 2005 the Company recorded $2.7 million revenue subject to refund for estimated earnings above 12.25 percent retail ROE.

The Company is required to file a general rate case by July 1, 2007, in response to which the Georgia PSC would be expected to determine whether the 2004 Retail Rate Plan should be continued, modified, or discontinued. Until then, the Company will not file for a general base rate increase unless its projected retail ROE falls below 10.25 percent. However, in connection with the Merger, the Company has requested Georgia PSC approval of a "merger transition adjustment" that would be used to adjust Savannah Electric's existing base rates to more closely match the existing base rates for the Company. See Note 3 to the financial statements under "Retail Regulatory Matters - Rate Plans" for additional information.

Plant McIntosh Construction Project

In December 2002 after a competitive bidding process, the Georgia PSC certified PPAs between Southern Power and the Company and Savannah Electric for capacity from Plant McIntosh Units 10 and 11, construction of which was completed in June 2005. In April 2003, Southern Power applied for FERC approval of these PPAs. In July 2003, the FERC accepted the PPAs to become effective June 1, 2005, subject to refund, and ordered that hearings be held. Intervenors opposed the FERC's acceptance of the PPAs, alleging that they did not meet the applicable standards for market-based rates between affiliates. To ensure the timely completion of the Plant McIntosh construction project and the availability of the units in the summer of 2005 for their retail customers, in May 2004, the Company and Savannah Electric requested the Georgia PSC to direct them to acquire the Plant McIntosh construction project. The Georgia PSC issued such an order and the transfer occurred on May 24, 2004 at a total cost of approximately $415 million, including

$14 million of transmission interconnection facilities. Subsequently, Southern Power filed a request to withdraw the PPAs and to terminate the ongoing FERC proceedings. In August 2004, the FERC issued a notice accepting the request to withdraw the PPAs and permitting such request to become effective by operation of law. However, the FERC made no determination on what additional steps may need to be taken with respect to testimony provided in the proceedings. See "FERC Matters - Intercompany Interchange Contract" above for additional information.

In connection with the 2004 Retail Rate Plan, the Georgia PSC approved the transfer of the Plant McIntosh construction project at a total fair market value of approximately $385 million. This value reflected an approximate $16 million disallowance, of which $13 million was attributable to the Company, and reduced the Company's 2004 net income by approximately $8 million. The Georgia PSC also certified a total completion cost of $547 million for the project. In June 2005, Plant McIntosh Units 10 and 11 were placed in service at a total cost that did not exceed the certified amount. Under the 2004 Retail Rate Plan, the Plant McIntosh revenue requirements impact will be reflected in the Company's rates evenly over the three years ending 2007. See Note 3 to the financial statements under "Retail Regulatory Matters -- Rate Plans" and "Plant McIntosh Construction Project" for additional information.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. In recent months, the Company has experienced higher than expected fuel costs for coal and natural gas. Those higher fuel costs have increased the under recovered fuel costs included in the balance sheets herein.

In May 2005, the Georgia PSC approved the Company's request to increase customer fuel rates by approximately 9.5 percent to recover under recovered fuel costs of approximately $508 million existing as of May 31, 2005 over a four-year period that began June 1, 2005. Under recovered fuel amounts for the period subsequent to June 1, 2005 totaled $327.5 million through December 31, 2005. The Georgia PSC's order instructed that such amounts be reviewed semi-annually beginning February 2006. If the amount under or over recovered exceeds $50 million at the evaluation date, the Company would be required to file for a temporary fuel rate change. In addition, Savannah Electric's under recovered fuel costs totaled $77.7 million at December 31, 2005. In accordance with the Georgia PSC order, Savannah Electric was scheduled to file an additional request for a fuel cost recovery increase in January 2006. The Company has agreed with a Georgia PSC staff recommendation to forego the temporary fuel rate process, and Savannah Electric has postponed its scheduled filing. Instead, the Company and Savannah Electric will file a combined request in March 2006 to increase the Company's fuel cost recovery rate.

The case will seek approval of a fuel cost recovery rate based upon future fuel cost projections for the combined Company and Savannah Electric generating fleet as well as the under recovered fuel balances existing at June 30, 2006. The new fuel cost recovery rate would be billed beginning in July 2006 to all of the Company's customers, including the existing Savannah Electric customers. Under recovered amounts as of the date of the Merger will be paid by the appropriate customer groups.

In August 2005, the Georgia PSC initiated an investigation of Savannah Electric's fuel practices. In February 2006, an investigation of the Company's fuel practices was initiated. The Company and Savannah Electric are responding to data requests and cooperating in the investigations. The final outcome of this matter cannot now be determined.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable cost and amounts billed in current regulated rates. Accordingly, any increase in the billing factor would have no significant effect on the Company's revenues or net income, but would increase annual cash flow.

Nuclear

As part of a potential expansion of Plant Vogtle, the Company and Southern Nuclear have notified the Nuclear Regulatory Commission (NRC) of their intent to apply for an early site permit (ESP) this year and a combined construction and operating license (COL) in 2008. In addition, a reactor design from Westinghouse Electric Company has been selected and a purchase agreement is being negotiated. Participation agreements have been reached with each of the existing Plant Vogtle co-owners. See Note 4 to the financial statements for additional information on

these co-owners. At this point, no final decision has been made regarding actual construction. The NRC's streamlined licensing process for new nuclear units allows utilities to seek regulatory approval at various stages. These stages include design certification, which is obtained by the reactor vendor, and the ESP and COL, which are each obtained by the owner-operators of the units. An ESP indicates site approval is obtained before a company decides to build and the COL provides regulatory approval for building and operating the plant. In addition, any generation by the Company must be certified by the Georgia PSC.

Southern Company also is participating in NuStart Energy Development, LLC (NuStart Energy), a broad-based nuclear industry consortium formed to share the cost of developing a COL and the related NRC review. NuStart Energy plans to complete detailed engineering design work and to prepare COL applications for two advanced reactor designs, then to choose one of the applications and file it for NRC review and approval. The COL ultimately is expected to be transferred to one or more of the consortium companies; however, at this time, none of them have committed to build a new nuclear plant.

Other Matters

In accordance with Financial Accounting Standards Board (FASB) Statement No. 87, Employers' Accounting for Pensions, the Company recorded non-cash pension income, before tax, of approximately $21 million, $35 million, and $54 million in 2005, 2004, and 2003, respectively. Postretirement benefit costs for the Company were $47 million, $44 million, and $41 million in 2005, 2004, and 2003, respectively. Both pension and postretirement costs are expected to trend upward. Such amounts are dependent on several factors including trust earnings and changes to the plans. A portion of pension income and postretirement benefit costs is capitalized based on construction-related labor charges. For the Company, pension income or expense and postretirement benefit costs are a component of the regulated rates and generally do not have a long-term effect on net income. For more information regarding pension and postretirement benefits, see Note 2 to the financial statements.

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

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

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

Electric Utility Regulation

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

As reflected in Note 1 to the financial statements under "Regulatory Assets and Liabilities," significant regulatory assets and liabilities have been recorded.

Management reviews the ultimate recoverability of these regulatory assets and liabilities based on applicable regulatory guidelines and accounting principles generally accepted in the United States. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

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

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

Unbilled Revenues

Revenues related to the sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated. Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, power delivery volume, and other operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.

New Accounting Standards

Income Taxes

In December 2004, the FASB issued FASB Staff Position 109-1, Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004 (FSP 109-1), which requires that the generation deduction be accounted for as a special tax deduction rather than as a tax rate reduction. The Company adopted FSP 109-1 in the first quarter of 2005 with no material impact on its financial statements.

Conditional Asset Retirement Obligations

Effective December 31, 2005, the Company adopted the provision of FASB Interpretation No. 47, Conditional Asset Retirement Obligations (FIN 47), which requires that an asset retirement obligation be recorded even though the timing and/or method of settlement are conditional on future events. Prior to December 2005, the Company did not recognize asset retirement obligations for asbestos removal because the timing of retirements was dependent on future events. For additional information, see Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal."

At December 31, 2005, the Company recorded additional asset retirement obligations (and assets) of approximately $91 million. The adoption of FIN 47 did not have any effect on the Company's income statement.

Stock Options

On January 1, 2006, the Company adopted FASB Statement No. 123R, Share-Based Payment, on a modified prospective basis. This statement requires that compensation cost relating to share-based payment transactions be recognized in financial statements. That cost will be measured based on the grant date fair value of the equity or liability instruments issued. Although the compensation expense required under the revised statement differs slightly, the impacts on the Company's financial statements are similar to the pro forma disclosures included in Note 1 to the financial statements under "Stock Options."

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition continued to be stable at December 31, 2005 with emphasis on cost control measures combined with significantly lower costs of capital, achieved through the refinancing and/or redemption of higher-cost securities. Cash flow from operations increased $56 million resulting primarily from increased retail operating revenues (see RESULTS OF OPERATIONS herein), partially offset by the increase in under recovered deferred fuel costs.

Fuel costs are generally recoverable in future periods and are reflected on the balance sheets as under recovered regulatory clause revenues. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information.

In 2005, gross utility plant additions were $906 million. These additions were primarily related to Plant McIntosh Units 10 and 11, transmission and distribution facilities, nuclear fuel, and equipment to comply with environmental standards. The majority of funds needed for gross property additions for the last several years have been provided from operating activities and capital contributions from Southern Company. The statements of cash flows provide additional details.

The Company's ratio of common equity to total capitalization -- including short-term debt -- was 48.3 percent in 2005, 47.7 percent in 2004, and 48.3 percent in 2003. The Company has received investment grade ratings from the major rating agencies.

Sources of Capital

The Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows. However, the type and timing of any future financings, if needed, will depend on market conditions, regulatory approval, and other factors.

The issuance of long-term securities by the Company is subject to the approval of the Georgia PSC. In addition, the issuance of short-term debt securities by the Company is subject to regulatory approval by the FERC following the repeal of the Public Utility Holding Company Act of 1935, as amended, on February 8, 2006. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the appropriate regulatory authorities, as well as the amounts registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company.

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

To meet short-term cash needs and contingencies, the Company had credit arrangements with banks totaling $780 million, of which $778 million was unused, at the beginning of 2006. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper and extendible commercial notes at the request and for the benefit of the Company and the other retail operating companies.

Proceeds from such issuances for the benefit of the Company are loaned directly to the Company and are not commingled with proceeds from issuances for the benefits of any other operating company. The obligations of each company under these arrangements are several; there is no cross affiliate credit support. As of December 31, 2005, the Company had outstanding $268 million of commercial paper and no extendible commercial notes.

At the beginning of 2006, bank credit arrangements were as follows:

		Expires		
Total	Unused	2006	2007	2010
		(in millions)		
$780	$778	$70	$350	$360

The credit arrangements that expire in 2006 allow for the execution of term loans for an additional two-year period.

Financing Activities

During 2005, the Company issued $810 million of long-term debt. The issuances were used to refund $635 million of long-term debt and to fund the Company's ongoing construction program.

Subsequent to December 31, 2005, the Company redeemed all of its outstanding preferred stock at a redemption price of $107 per share.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- or Baa3 or below. Generally, collateral may be provided for by a Southern Company guaranty, letter of credit, or cash. These contracts are primarily for physical electricity purchases and sales. At December 31, 2005, the maximum potential collateral requirements at a BBB- or Baa3 rating were approximately $6 million. The maximum potential collateral requirements at a rating below BBB- or Baa3 were approximately $245 million.

The Company is also party to certain derivative agreements that could require collateral and/or accelerated payment in the event of a credit rating change to below investment grade. These agreements are primarily for natural gas price risk management activities. At December 31, 2005, the Company had no material exposure related to these agreements.

Market Price Risk

Due to cost-based rate regulation, the Company has limited exposure to market rate 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 and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress tests, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company has entered into forward starting interest rate swaps that have been designated as hedges. These swaps have a notional amount of $300 million and are related to anticipated debt issuances over the next two years. The weighted average interest rate on outstanding variable long-term debt that has not been hedged at January 1, 2006 was 3.56 percent. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $3.3 million at January 1, 2006. For further information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

To mitigate residual risks relative to movements in electricity prices, the Company enters into fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, into similar contracts for gas purchases.

The Company has implemented a fuel hedging program at the instruction of the Georgia PSC. Fair

value of changes in energy-related derivative contracts and year-end valuations were as follows at December 31:

	Changes in Fair Value	
	2005	2004
	(in millions)	
Contracts beginning of year	**$5.8**	$ 3.2
Contracts realized or settled	**(40.0)**	(12.2)
Current period changes (a)	**60.8**	14.8
Contracts end of year	**$26.6**	$ 5.8

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

	Source of 2005 Year-End Valuation Prices		
	Total	Maturity	
	Fair Value	Year 1	1-3 Years
		(in millions)	
Actively quoted	**$26.8**	$16.4	$10.4
External sources	**(0.2)**	(0.2)	-
Contracts end of year	**$26.6**	$16.2	$10.4

Unrealized gains and losses from mark to market adjustments on derivative contracts related to the Company's fuel hedging programs are recorded as regulatory assets and liabilities. Realized gains and losses from these programs are included in fuel expense and are recovered through the Company's fuel cost recovery mechanism. Of the net gains, the Company is allowed to retain 25 percent in earnings. In 2005, the Company had a total net gain of $64.1 million, of which the Company retained $16.0 million. See Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Hedging Program" for additional information. Gains and losses on derivative contracts that are not designated as hedges are recognized in the statements of income as incurred. At December 31, 2005, the fair value of derivative energy contracts was reflected in the financial statements as follows:

	Amounts
	(in millions)
Regulatory liabilities, net	$26.7
Net income	(0.1)
Total fair value	$26.6

Unrealized gains (losses) recognized in income in 2005, 2004, and 2003 were not material. The Company is exposed to market price risk in the event of nonperformance by counterparties to the derivative energy contracts. The Company's policy is to enter into agreements with counterparties that have investment grade credit ratings by Moody's and Standard & Poor's or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to be $1.3 billion for 2006, $1.4 billion for 2007, and $1.3 billion for 2008. Environmental expenditures included in these amounts are $410 million, $674.6 million, and $515.8 million for 2006, 2007, and 2008, respectively. Actual construction costs may vary from this estimate because of changes in such factors as: business conditions; environmental regulations; nuclear plant regulations; FERC rules and transmission regulations; load projections; the cost and efficiency of construction labor, equipment, and materials; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

As a result of requirements by the NRC, the Company has established external trust funds for nuclear decommissioning costs. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning." Also as discussed in Note 1 to the financial statements under "Nuclear Fuel Disposal Costs," in 1993 the DOE implemented a special assessment over a 15-year period on utilities with nuclear plants to be used for the decontamination and decommissioning of its nuclear fuel enrichment facilities.

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the Georgia PSC and the FERC.

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

Amounts in the following chart exclude any effects on the Company of the Merger.

Contractual Obligations

	2006	2007-2008	2009-2010	After 2010	Total
			(in millions)		
Long-term debt [a] --					
Principal	$153	$306	$282	$4,563	$5,304
Interest	265	496	468	4,989	6,218
Preferred stock	15	-	-	-	15
Commodity derivative obligations[b]	12	-	-	-	12
Operating leases	34	58	44	58	194
Purchase commitments[c] --					
Capital [d]	1,251	2,738	2,421	-	6,410
Coal	1,579	2,220	694	40	4,533
Nuclear fuel	44	42	25	64	175
Natural gas[e]	577	525	511	2,047	3,660
Purchased power	343	689	559	994	2,585
Long-term service agreements	7	18	24	144	193
Trusts[f] --					
Nuclear decommissioning	7	14	14	117	152
Postretirement benefits	18	41	-	-	59
DOE assessments	4	-	-	-	4
Total	$4,309	$7,147	$5,042	$13,016	$29,514

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2006, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest risk.

(b) For additional information see Notes 1 and 6 to the financial statements herein.

(c) The Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses for the last three years were $1.5 billion, $1.4 billion, and $1.2 billion, respectively.

(d) The Company forecasts capital expenditures over a five-year period. Amounts represent current estimates of total expenditures, excluding those amounts related to contractual purchase commitments for uranium and nuclear fuel conversion, enrichment, and fabrication services. At December 31, 2005, significant purchase commitments were outstanding in connection with the construction program.

(e) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on the New York Mercantile Exchange future prices at December 31, 2005.

(f) Projections of nuclear decommissioning trust contributions are based on the 2004 Retail Rate Plan. The Company forecasts postretirement trust contributions over a three-year period. No contributions related to the Company's pension trust are currently expected during this period. See Note 2 to the financial statements for additional information related to the pension and postretirement plans, including estimated benefit payments. Certain benefit payments will be made through the related trusts. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2005 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales growth, storm cost recovery and repairs, environmental regulations and expenditures, the Company's projections for postretirement benefit trust contributions, financing activities, access to sources of capital, the proposed merger of Savannah Electric and the Company, the impacts of the adoption of new accounting rules, completion of construction projects, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will", "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory change, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, and implementation of the Energy Policy Act of 2005, and also changes in environmental, tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including FERC matters and the pending EPA civil action against the Company;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and population, and business growth (and declines);
- available sources and costs of fuels;
- ability to control costs;
- investment performance of the Company's employee benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate cases related to fuel cost recovery;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due;
- the ability to obtain new short- and long-term contracts with neighboring utilities;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents similar to the August 2003 power outage in the Northeast;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports, including the Form 10-K, filed by the Company from time to time with the Securities and Exchange Commission.

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

STATEMENTS OF INCOME

For the Years Ended December 31, 2005, 2004, and 2003

Georgia Power Company 2005 Annual Report

	2005	2004	2003
		(in thousands)	
Operating Revenues:			
Retail sales	**$5,642,812**	$4,776,985	$4,309,972
Sales for resale --			
Non-affiliates	**519,673**	246,545	259,376
Affiliates	**264,989**	166,245	174,855
Other revenues	**206,729**	181,033	169,304
Total operating revenues	**6,634,203**	5,370,808	4,913,507
Operating Expenses:			
Fuel	**1,830,829**	1,232,496	1,103,963
Purchased power --			
Non-affiliates	**408,563**	304,978	258,621
Affiliates	**761,466**	671,098	516,944
Other operations	**949,722**	902,167	827,972
Maintenance	**531,168**	498,114	419,206
Depreciation and amortization	**504,248**	275,488	349,984
Taxes other than income taxes	**259,825**	227,806	212,827
Total operating expenses	**5,245,821**	4,112,147	3,689,517
Operating Income	**1,388,382**	1,258,661	1,223,990
Other Income and (Expense):			
Allowance for equity funds used during construction	**26,808**	26,659	10,752
Interest income	**6,281**	6,657	15,625
Interest expense, net of amounts capitalized	**(221,199)**	(182,370)	(182,583)
Interest expense to affiliate trusts	**(59,510)**	(44,565)	-
Distributions on mandatorily redeemable preferred securities	**-**	(15,839)	(59,675)
Other income (expense), net	**5,742**	(11,362)	(10,551)
Total other income and (expense)	**(241,878)**	(220,820)	(226,432)
Earnings Before Income Taxes	**1,146,504**	1,037,841	997,558
Income taxes	**430,812**	379,170	366,311
Net Income	**715,692**	658,671	631,247
Dividends on Preferred Stock	**693**	670	670
Net Income After Dividends on Preferred Stock	**$714,999**	$658,001	$630,577

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

STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2005, 2004, and 2003

Georgia Power Company 2005 Annual Report

	2005	2004	2003
		(in thousands)	
Operating Activities:			
Net income	$ 715,692	$ 658,671	$ 631,247
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization	592,264	361,958	424,321
Deferred income taxes and investment tax credits, net	231,708	251,623	199,265
Deferred expenses - affiliates	1,268	(10,563)	(7,399)
Allowance for equity funds used during construction	(26,808)	(26,659)	(10,752)
Pension, postretirement, and other employee benefits	(19,468)	(15,868)	(30,225)
Tax benefit of stock options	15,711	9,701	11,649
Other, net	(11,068)	(19,764)	18,929
Changes in certain current assets and liabilities --			
Receivables	(591,498)	(227,204)	(4,395)
Fossil fuel stock	2,528	(46,730)	(17,490)
Materials and supplies	(53,942)	618	(7,677)
Prepaid income taxes	(43,626)	14,358	(3,951)
Other current assets	4,108	(23,672)	1,599
Accounts payable	110,118	132,001	(62,553)
Accrued taxes	85,098	(64,563)	52,348
Accrued compensation	3,822	(6,664)	(3,111)
Other current liabilities	33,289	5,836	19,845
Net cash provided from operating activities	1,049,196	993,079	1,211,650
Investing Activities:			
Property additions	(842,870)	(741,151)	(717,993)
Nuclear decommissioning trust fund purchases	(381,235)	(541,048)	(656,806)
Nuclear decommissioning trust fund sales	372,536	532,349	648,107
Purchase of property from affiliates	-	(339,750)	(2)
Cost of removal net of salvage	(29,428)	(21,756)	(28,265)
Change in construction payables, net of joint owner portion	4,037	413	(32,223)
Other	(315)	(4,961)	1,008
Net cash used for investing activities	(877,275)	(1,115,904)	(786,174)
Financing Activities:			
Increase (decrease) in notes payable, net	59,509	70,956	(220,400)
Proceeds --			
Senior notes	625,000	600,000	1,000,000
Pollution control bonds	185,000	-	-
Mandatorily redeemable preferred securities	-	200,000	-
Capital contributions from parent company	149,034	260,068	40,809
Redemptions --			
Pollution control bonds	(185,000)	-	-
Senior notes	(450,000)	(200,000)	(665,000)
Mandatorily redeemable preferred securities	-	(200,000)	-
Payment of preferred stock dividends	(546)	(654)	(696)
Payment of common stock dividends	(556,100)	(565,500)	(565,800)
Other	(21,679)	(17,247)	(22,563)
Net cash provided from (used for) financing activities	(194,782)	147,623	(433,650)
Net Change in Cash and Cash Equivalents	(22,861)	24,798	(8,174)
Cash and Cash Equivalents at Beginning of Year	33,497	8,699	16,873
Cash and Cash Equivalents at End of Year	$ 10,636	$ 33,497	$ 8,699
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $10,871, $8,920, and $5,428 capitalized, respectively)	$250,445	$228,190	$215,463
Income taxes (net of refunds)	207,973	127,115	145,048

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

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BALANCE SHEETS
At December 31, 2005 and 2004
Georgia Power Company 2005 Annual Report

Assets	2005	2004
		(in thousands)
Current Assets:		
Cash and cash equivalents	**$ 10,636**	$ 33,497
Receivables --		
Customer accounts receivable	**418,154**	317,937
Unbilled revenues	**141,875**	140,027
Under recovered regulatory clause revenues	**454,683**	345,542
Other accounts and notes receivable	**110,397**	94,377
Affiliated companies	**84,597**	17,042
Accumulated provision for uncollectible accounts	**(8,647)**	(7,100)
Fossil fuel stock, at average cost	**181,739**	184,267
Vacation pay	**59,190**	57,372
Materials and supplies, at average cost	**323,908**	270,422
Prepaid expenses	**70,825**	32,695
Other	**50,248**	28,262
Total current assets	**1,897,605**	1,514,340
Property, Plant, and Equipment:		
In service	**19,603,249**	18,681,533
Less accumulated provision for depreciation	**7,575,926**	7,217,607
	12,027,323	11,463,926
Nuclear fuel, at amortized cost	**134,798**	124,745
Construction work in progress	**563,155**	766,140
Total property, plant, and equipment	**12,725,276**	12,354,811
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**68,188**	66,192
Nuclear decommissioning trusts, at fair value	**486,591**	459,194
Other	**71,468**	64,571
Total other property and investments	**626,247**	589,957
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**500,882**	505,664
Prepaid pension costs	**476,458**	450,270
Deferred under recovered regulatory clause revenues	**295,116**	-
Other regulatory assets	**330,483**	246,462
Other	**195,716**	160,834
Total deferred charges and other assets	**1,798,655**	1,363,230
Total Assets	**$17,047,783**	$15,822,338

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

BALANCE SHEETS
At December 31, 2005 and 2004
Georgia Power Company 2005 Annual Report

Liabilities and Stockholder's Equity	2005	2004
		(in thousands)
Current Liabilities:		
Securities due within one year	$ 167,317	$ 452,498
Notes payable	267,743	208,233
Accounts payable --		
Affiliated	285,019	194,253
Other	360,455	310,763
Customer deposits	129,293	115,661
Accrued taxes --		
Income taxes	150,896	78,269
Other	204,778	129,520
Accrued interest	88,885	74,529
Accrued vacation pay	45,602	44,894
Accrued compensation	137,303	127,340
Other	120,312	83,632
Total current liabilities	1,957,603	1,819,592
Long-term Debt (See accompanying statements)	4,179,218	3,709,852
Long-term Debt Payable to Affiliated Trusts (See accompanying statements)	969,073	969,073
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	2,730,303	2,556,040
Deferred credits related to income taxes	158,759	170,973
Accumulated deferred investment tax credits	287,726	300,018
Employee benefit obligations	358,137	331,002
Asset retirement obligations	627,465	504,515
Other cost of removal obligations	404,614	411,692
Other regulatory liabilities	97,015	84,678
Other	63,335	59,733
Total deferred credits and other liabilities	4,727,354	4,418,651
Total Liabilities	11,833,248	10,917,168
Preferred Stock (See accompanying statements)	-	14,609
Common Stockholder's Equity (See accompanying statements)	5,214,535	4,890,561
Total Liabilities and Stockholder's Equity	$17,047,783	$15,822,338
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION

At December 31, 2005 and 2004

Georgia Power Company 2005 Annual Report

	2005	2004	2005	2004
	(in thousands)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable --				
5.50% due December 1, 2005	$ -	$ 150,000		
Variable rate (1.66% to 1.96% at 1/1/05) due 2005	-	300,000		
6.20% due February 1, 2006	**150,000**	150,000		
4.875% due July 15, 2007	**300,000**	300,000		
4.10% due August 15, 2009	**125,000**	125,000		
Variable rate (4.53% at 1/1/06) due 2009	**150,000**	150,000		
4.00% to 6.00% due 2011-2045	**1,850,000**	1,225,000		
Total long-term notes payable	**2,575,000**	2,400,000		
Other long-term debt --				
Pollution control revenue bonds -- non-collateralized:				
2.83% to 5.45% due 2012-2034	**812,560**	812,560		
Variable rate (2.82% to 3.08% at 1/1/06) due 2011-2032	**873,330**	873,330		
Total other long-term debt	**1,685,890**	1,685,890		
Capitalized lease obligations	**74,484**	76,982		
Unamortized debt premium (discount), net	**(3,448)**	(522)		
Total long-term debt (annual interest requirement -- $205.5 million)	**4,331,926**	4,162,350		
Less amount due within one year	**152,708**	452,498		
Long-term debt excluding amount due within one year	**4,179,218**	3,709,852	**40.3%**	38.7%
Long-term Debt Payable to Affiliated Trusts:				
4.88% to 7.13% due 2042 (annual interest requirement -- $59.5 million)	**969,073**	**969,073**	**9.4**	10.1
Cumulative Preferred Stock:				
$100 stated value at 4.60%				
Authorized -- 5,000,000 shares				
Outstanding -- 145,689 shares (annual dividend requirement -- $0.7 million)	**14,609**	14,609		
Less amount due within one year	**14,609**	-		
Total cumulative preferred stock excluding amount due within one year	**-**	14,609	**0.0**	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	**2,643,012**	2,478,268		
Retained earnings	**2,261,698**	2,102,798		
Accumulated other comprehensive income (loss)	**(34,425)**	(34,755)		
Total common stockholder's equity	**5,214,535**	4,890,561	**50.3**	51.0
Total Capitalization	**$10,362,826**	$9,584,095	**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, 2005, 2004, and 2003

Georgia Power Company 2005 Annual Report

	Common Stock	Paid-In Capital	Retained Earnings	Other Comprehensive Income (loss)	Total
			(in thousands)		
Balance at December 31, 2002	$344,250	$2,156,080	$1,945,520	$(11,403)	$4,434,447
Net income after dividends on preferred stock	-	-	630,577	-	630,577
Capital contributions from parent company	-	52,458	-	-	52,458
Other comprehensive income (loss)	-	-	-	(11,471)	(11,471)
Cash dividends on common stock	-	-	(565,800)	-	(565,800)
Balance at December 31, 2003	**344,250**	**2,208,538**	**2,010,297**	**(22,874)**	**4,540,211**
Net income after dividends on preferred stock	-	-	658,001	-	658,001
Capital contributions from parent company	-	269,769	-	-	269,769
Other comprehensive income (loss)	-	-	-	(11,881)	(11,881)
Cash dividends on common stock	-	-	(565,500)	-	(565,500)
Other	-	(39)	-	-	(39)
Balance at December 31, 2004	**344,250**	**2,478,268**	**2,102,798**	**(34,755)**	**4,890,561**
Net income after dividends on preferred stock	-	-	**714,999**	-	**714,999**
Capital contributions from parent company	-	**164,745**	-	-	**164,745**
Other comprehensive income (loss)	-	-	-	**330**	**330**
Cash dividends on common stock	-	-	**(556,100)**	-	**(556,100)**
Other	-	**(1)**	**1**	-	-
Balance at December 31, 2005	**$344,250**	**$2,643,012**	**$2,261,698**	**$(34,425)**	**$5,214,535**

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

STATEMENTS OF COMPREHENSIVE INCOME

For the Years Ended December 31, 2005, 2004, and 2003

Georgia Power Company 2005 Annual Report

	2005	2004	2003
		(in thousands)	
Net income after dividends on preferred stock	**$714,999**	$658,001	$630,577
Other comprehensive income (loss):			
Change in additional minimum pension liability, net of tax of $(1,981), $(3,861) and $(5,133), respectively	**(3,140)**	(6,122)	(8,138)
Change in fair value of marketable securities, net of tax of $317 and $(114)	**501**	(181)	-
Changes in fair value of qualifying hedges, net of tax of $1,214, $(5,046) and $(3,241), respectively	**1,925**	(7,999)	(5,550)
Less: Reclassification adjustment for amounts included in net income, net of tax of $848, $1,528 and $1,208, respectively	**1,044**	2,421	2,217
Total other comprehensive income (loss)	**330**	(11,881)	(11,471)
Comprehensive Income	**$715,329**	$646,120	$619,106

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Georgia Power Company (Company) is a wholly owned subsidiary of Southern Company, which is the parent company of five retail operating companies, Southern Power Company (Southern Power), Southern Company Services (SCS), Southern Communications Services (SouthernLINC Wireless), Southern Company Holdings (Southern Holdings), Southern Nuclear Operating Company (Southern Nuclear), Southern Telecom, and other direct and indirect subsidiaries. The retail operating companies -- Alabama Power, the Company, Gulf Power, Mississippi Power, and Savannah Electric -- provide electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast. Southern Power constructs, owns, and manages Southern Company's competitive generation assets and sells electricity at market-based rates in the wholesale market. Contracts among the retail operating companies and Southern Power -- related to jointly owned generating facilities, interconnecting transmission lines, or the exchange of electric power -- are regulated by the Federal Energy Regulatory Commission (FERC). SCS -- the system service company -- provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications services to the retail operating companies and also markets these services to the public within the Southeast. Southern Telecom provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding subsidiary for Southern Company's investments in synthetic fuels and leveraged leases and various other energy-related businesses. Southern Nuclear operates and provides services to Southern Company's nuclear power plants. In January 2006, Southern Company completed the sale of substantially all the assets of Southern Company Gas, its competitive retail natural gas marketing subsidiary.

The equity method is used for subsidiaries in which the Company has significant influence but does not control and for variable interest entities where the Company is not the primary beneficiary. Certain prior years' data presented in the financial statements have been reclassified to conform to current year presentation.

Southern Company was registered as a holding company under the Public Utility Holding Company Act of 1935, as amended (PUHCA), until its repeal on February 8, 2006, and Southern Company and its subsidiaries, including the Company, were subject to the regulatory provisions of the PUHCA. The Company is subject to regulation by the FERC and the Georgia Public Service Commission (PSC). The Company follows accounting principles generally accepted in the United States and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires the use of estimates and the actual results may differ from those estimates.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, purchasing, accounting and statistical analysis, finance and treasury, tax, information resources, marketing, auditing, insurance and pension administration, human resources, systems and procedures, and other services with respect to business and operations and power pool operations. Costs for these services amounted to $330 million in 2005, $292 million in 2004, and $303 million in 2003. Cost allocation methodologies used by SCS were approved by the Securities and Exchange Commission prior to the repeal of the PUHCA 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 $328 million in 2005, $311 million in 2004, and $289 million in 2003.

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. Billings under these agreements with Southern Power amounted to $5.2 million in 2005, $4.8 million in 2004, and $5.3 million in 2003.

The Company has an agreement with SouthernLINC Wireless under which the Company receives digital wireless communications services and purchases digital equipment. Costs for these services amounted to $7.3 million in 2005, $7.7 million in 2004, and $7.4 million in 2003.

Southern Company holds a 30 percent ownership in Alabama Fuel Products, LLC (AFP), which produces synthetic fuel. The Company has an agreement with an indirect subsidiary of Southern Company that provides services for AFP. Under this agreement, the Company provides certain accounting functions, including processing and paying fuel transportation invoices, and the Company is reimbursed for its expenses. Amounts billed under this agreement totaled approximately $61 million in 2005, $53 million in 2004, and $38 million in 2003. In addition, the Company purchases synthetic fuel from AFP for use at plants Branch, McDonough, and Bowen. Fuel purchases totaled $216 million in 2005, $163 million in 2004, and $91 million in 2003.

The Company has entered into several purchased power agreements (PPAs) with Southern Power for capacity and energy. Expenses associated with these PPAs were $419 million, $282 million, and $203 million in 2005, 2004, and 2003, respectively. Additionally, the Company recorded a reduction of $1 million and an increase of $11 million of prepaid capacity expenses included on the balance sheets at December 31, 2005 and 2004, respectively. See Note 7 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, the Company operates Plant Scherer, and Gulf Power reimburses the Company for its proportionate share of the related expenses which were $4.3 million in 2005, $6.8 million in 2004, and $4.9 million in 2003. The Company has an agreement with Savannah Electric under which the Company jointly owns a portion of Plant McIntosh. Under this agreement, Savannah Electric operates Plant McIntosh, and the Company reimburses Savannah Electric for its proportionate share of the related expenses which were $5.5 million in 2005, $3.3 million in 2004, and $3.7 million in 2003. See Note 4 for additional information.

The Company provides incidental services to other Southern Company subsidiaries which are generally minor in duration and amount. However, with the hurricane damage experienced by Alabama Power, Gulf Power, and Mississippi Power in the last two years, assistance provided to aid in storm restoration, including company labor, contract labor, and materials, has caused an increase in these activities. The total amount of storm assistance provided to Alabama Power, Gulf Power, and Mississippi Power in 2005 was $4.1 million, $4.4 million, and $55 million, respectively. The total amount of storm assistance provided to Alabama Power and Gulf Power in 2004 was $4.1 million and $6.4 million, respectively. These activities were billed at cost.

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

The retail operating companies, including the Company, and Southern Power 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 7 under "Fuel Commitments" for additional information.

The Company has entered into an agreement to merge with Savannah Electric. See Note 3 under "Retail Regulatory Matters – Merger" 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.

Regulatory assets and (liabilities) reflected in the Company's balance sheets at December 31 relate to the following:

	2005	2004	Note
	(in millions)		
Deferred income tax charges	$ 501	$506	(a)
Premium on reacquired debt	170	177	(b)
Corporate building lease	52	53	(e)
Vacation pay	59	57	(d)
Postretirement benefits	18	20	(e)
DOE assessments	6	10	(c)
Generating plant outage costs	46	40	(g)
Other regulatory assets	33	11	(e)
Asset retirement obligation	65	(20)	(a)
Other cost of removal obligations	(404)	(412)	(a)
Deferred income tax credits	(159)	(171)	(a)
Environmental remediation	(19)	(22)	(f)
Purchased power	(33)	-	(f)
Other regulatory liabilities	(30)	(6)	(e)
Total	$ 305	$243	

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

(a) Asset retirement and removal liabilities are recorded, deferred income tax assets are recovered, and deferred tax liabilities are amortized over the related property lives, which may range up to 60 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities.

(b) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue which may range up to 50 years.

(c) Assessments for the decontamination and decommissioning of the DOE's nuclear fuel enrichment facilities are recorded annually from 1993 through 2006.

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

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

(f) Amortized over a three-year period ending in 2007. See Note 3 under "Retail Regulatory Matters - Rate Plans."

(g) See "Property, Plant, and Equipment" herein.

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, including plant, exists and, if impaired, write down the assets to their fair value. All regulatory assets and liabilities are reflected in rates.

Revenues

Energy and other revenues are recognized as services are provided. Unbilled revenues are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between the actual recoverable costs and amounts billed in current regulated rates.

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

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense includes the cost of purchased emission allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel. Total charges for nuclear fuel included in fuel expense amounted to $70 million in 2005, $73 million in 2004, and $74 million in 2003.

Nuclear Fuel Disposal Costs

The Company has contracts with the U.S. Department of Energy (DOE) that provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent nuclear fuel in 1998 as required by the contracts, and the Company is pursuing legal remedies against the government for breach of contract. Sufficient pool storage capacity for spent fuel is available at Plant Vogtle to maintain full-core discharge capability for both units into 2015. Construction of an on-site dry storage facility at Plant Vogtle is expected to begin in sufficient time to maintain pool full-core discharge capability. At Plant Hatch, an on-site dry storage facility is operational and can be expanded to accommodate spent fuel through the life of the plant.

Also, the Energy Policy Act of 1992 required the establishment of a Uranium Enrichment Decontamination and Decommissioning Fund, which is funded in part by a special assessment on utilities with nuclear plants. This assessment has been paid over a 15-

year period; the final installment is scheduled to occur in 2006. 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 interest, estimates its remaining liability at December 31, 2005 under this law to be approximately $4 million.

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.

Manufacturer's Tax Credits

The State of Georgia provides a tax credit for qualified investment property to manufacturing companies that construct new facilities. The credit ranges from 1 percent to 8 percent of qualified construction expenditures depending upon the county in which the new facility is located. The Company's policy is to recognize these credits when management believes that they are more likely than not to be allowed by the Georgia Department of Revenue. Manufacturer's tax credits of $12.5 million, $12.9 million, and $12.0 million were recorded in 2005, 2004, and 2003, respectively.

Property, Plant, and Equipment

The Company's property, plant, and equipment consisted of the following at December 31 (in millions):

	2005	2004
Generation	**$ 9,571**	$ 9,002
Transmission	**2,994**	2,870
Distribution	**5,953**	5,744
General	**1,057**	1,038
Plant acquisition adjustment	**28**	28
Total plant in service	**$ 19,603**	$18,682

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

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense as incurred or performed with the exception of certain generating plant maintenance costs. As mandated by the Georgia PSC, the Company defers and amortizes nuclear refueling costs over the unit's operating cycle before the next refueling. The refueling cycles are 18 and 24 months for plants Vogtle and Hatch, respectively. In accordance with the Georgia PSC 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.

Depreciation and Amortization

Depreciation of the original cost of plant in service is provided primarily by using composite straight-line rates, which approximated 2.6 percent in 2005, 2.6 percent in 2004, and 2.7 percent in 2003. Depreciation studies are conducted periodically to update the composite rates that are approved by the Georgia PSC. In connection with the new retail rate plan for the Company ending December 31, 2007 (2004 Retail Rate Plan), effective January 1, 2005, the depreciation rates were revised by the Georgia PSC. The revised depreciation rates had no material impact on the Company's financial statements.

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.

Under the three-year retail rate plan for the Company ending December 31, 2004 (2001 Retail Rate Plan), the Company discontinued recording accelerated depreciation and amortization. Also, the Company was ordered to amortize $333 million, the cumulative balance previously expensed, equally over three years as a credit to amortization expense beginning January

2002. Additionally, the Company was ordered to recognize new Georgia PSC certified purchased power costs in rates evenly over the three years covered by the 2001 Retail Rate Plan. As a result of the purchased power regulatory adjustment, the Company recorded amortization expenses of $14 million in 2003. The Company recorded a credit to amortization expense of $77 million in 2004. See Note 3 under "Retail Regulatory Matters - Rate Plans" for additional information.

Asset Retirement Obligations and Other Costs of Removal

Effective January 1, 2003, the Company adopted FASB Statement No. 143, Accounting for Asset Retirement Obligations. Statement No. 143 established new accounting and reporting standards for legal obligations associated with the ultimate costs of retiring long-lived assets. The present value of the ultimate costs for an asset's future retirement is recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In addition, effective December 31, 2005, the Company adopted the provisions of FASB Interpretation No. 47, Conditional Asset Retirement Obligations (FIN 47), which requires that an asset retirement obligation be recorded even though the timing and/or method of settlement are conditional on future events. Prior to December 2005, the Company did not recognize asset retirement obligations for asbestos removal because the timing of their retirements was dependent on future events. The Company has received approval from the Georgia PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations will continue to be reflected on the balance sheets as a regulatory liability. Therefore, the Company had no cumulative effect to net income resulting from the adoption of Statement No. 143 or FIN 47.

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. The fair value of assets legally restricted for settling retirement obligations related to nuclear facilities as of December 31, 2005 was $487 million. In addition, the Company has recognized retirement obligations related to various landfill sites, ash ponds, and underground storage tanks. The Company also recorded additional asset retirement obligations (and assets) of approximately $91 million related to asbestos removal. The Company has also identified retirement obligations related to certain transmission and distribution facilities, leasehold improvements, equipment on customer property, and property associated with the Company's rail lines. However, liabilities for the removal of these assets have not been 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 allowed removal costs in accordance with its regulatory treatment. Any difference between costs recognized under Statement No. 143 and FIN 47 and those reflected in rates are recognized as either a regulatory asset or liability in the balance sheets as ordered by the Georgia PSC. See "Nuclear Decommissioning" herein for further information on amounts included in rates.

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

	2005	2004
	(in millions)	
Balance beginning of year	**$505**	$476
Liabilities incurred	**91**	-
Liabilities settled	**(2)**	(2)
Accretion	**33**	31
Balance end of year	**$627**	$505

If FIN 47 had been adopted as of December 31, 2004, the pro forma asset retirement obligations would have been $591 million.

Nuclear Decommissioning

The Nuclear Regulatory Commission (NRC) requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has external trust funds to comply with the NRC's regulations. Use of the funds is restricted to nuclear decommissioning activities and the funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and state PSCs, as well as the Internal Revenue Service (IRS). The trust funds are invested in a tax-

efficient manner in a diversified mix of equity and fixed income securities and are classified as available-for-sale. The trust funds are included in the balance sheets at fair value, as obtained from quoted market prices for the same or similar investments. Details of the securities held in these trusts at December 31 are as follows:

2005	Unrealized Gains	Unrealized Losses	Fair Value
		(in millions)	
Equity	$76.7	$(6.3)	$325.5
Debt	2.8	(0.8)	135.3
Other	-	-	25.8
Total	**$79.5**	**$(7.1)**	**$486.6**

2004	Unrealized Gains	Unrealized Losses	Fair Value
		(in millions)	
Equity	$68.7	$(4.0)	$308.2
Debt	5.3	(0.1)	138.0
Other	-	-	13.0
Total	$74.0	$(4.1)	$459.2

The contractual maturities of debt securities at December 31, 2005 are as follows: $3.2 million in 2006; $34.9 million in 2007-2010; $32.4 million in 2011-2015; and $57.2 million thereafter.

Sales of the securities held in the trust funds resulted in proceeds of $372.5 million, $532.3 million, and $648.1 million in 2005, 2004, and 2003, respectively, all of which were re-invested. Net realized gains (losses) were $12.6 million, $14.1 million, and $21.3 million in 2005, 2004, and 2003, respectively. Realized gains and losses are determined on a specific identification basis. In accordance with regulatory guidance, all realized and unrealized gains and losses are included in the regulatory liability for Asset Retirement Obligations in the balance sheets and are not included in net income or other comprehensive income. Unrealized gains and losses are considered non-cash transactions for purposes of the statements of cash flow. Unrealized losses were not material in any period presented and do not represent any impairment of the underlying investments.

Amounts previously recorded in internal reserves are being transferred into the external trust funds over periods approved by the Georgia PSC. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed plans with the NRC to ensure that, over time -- the deposits and earnings of the external trust funds will provide the minimum funding amounts prescribed by the NRC. Annual provisions for nuclear decommissioning are based on an annuity method as approved by the Georgia PSC. The amount expensed in 2005 and fund balances were as follows:

	Plant Hatch	Plant Vogtle
	(in millions)	
Amount expensed in 2005	$ -	$ 7
Accumulated provisions:		
External trust funds, at fair value	$313	$174
Internal reserves	-	1
Total	$313	$175

Site study cost is the estimate to decommission a specific facility as of the site study year. The estimated costs of decommissioning based on the most current study performed in 2003 for the Company's ownership interests in plants Hatch and Vogtle were as follows:

	Plant Hatch	Plant Vogtle
Decommissioning periods:		
Beginning year	2034	2027
Completion year	2065	2048
	(in millions)	
Site study costs:		
Radiated structures	$497	$452
Non-radiated structures	49	58
Total	$546	$510

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

Under the 2001 Retail Rate Plan, the Georgia PSC approved the annual decommissioning costs for ratemaking of $9 million. This amount was based on the NRC generic estimate to decommission the radioactive

portion of the facilities as of 2000. The estimates were $383 million and $282 million for plants Hatch and Vogtle, respectively. Significant assumptions used to determine the costs for ratemaking included an estimated inflation rate of 4.7 percent and an estimated trust earnings rate of 6.5 percent.

Under the 2004 Retail Rate Plan, effective January 1, 2005, the Georgia PSC decreased the annual decommissioning costs for ratemaking to $7 million. This amount is based on the NRC generic estimate to decommission the radioactive portion of the facilities as of 2003. The estimates are $421 million and $326 million for plants Hatch and Vogtle, respectively. Significant assumptions used to determine the costs for ratemaking include an estimated inflation rate of 3.1 percent and an estimated trust earnings rate of 5.1 percent. Another significant assumption used was the change in the operating license for Plant Hatch. In January 2002, the NRC granted the Company a 20-year extension of the licenses for both units at Plant Hatch which permits the operation of units 1 and 2 until 2034 and 2038, respectively. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for the anticipated cost of decommissioning.

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

In accordance with regulatory treatment, the Company records AFUDC. AFUDC represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, it increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation expense. Interest related to the construction of new facilities not included in the Company's retail rates is capitalized in accordance with standard interest capitalization requirements. For the years 2005, 2004, and 2003, the average AFUDC rates were 8.02 percent, 8.22 percent, and 5.51 percent, respectively. AFUDC and interest capitalized, net of taxes, were 4.7 percent and 4.9 percent of net income after dividends on preferred stock for 2005 and 2004, respectively, and less than 3 percent for 2003.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment provision is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change. See Note 3 under "Retail Regulatory Matters" and "Plant McIntosh Construction Project" for information regarding a regulatory disallowance by the Georgia PSC in December 2004.

Storm Damage Reserve

The Company maintains a reserve for property damage to cover the cost of damages from major storms to its transmission and distribution lines and the cost of uninsured damages to its generation facilities and other property as mandated by the Georgia PSC. The Company accrues $6.3 million annually that is recoverable through base rates. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for storm damage costs.

Environmental Cost Recovery

Under Georgia PSC ratemaking provisions, $22 million has been deferred in a regulatory liability account related to certain environmental insurance settlements. Under the 2004 Retail Rate Plan, this regulatory liability is being amortized over a three-year period beginning January 1, 2005. However, the Georgia PSC also approved an annual environmental accrual of $5.4 million. Environmental remediation expenditures are charged against the reserve as they are incurred. The annual accrual amount will be reviewed and adjusted in future regulatory proceedings.

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 average costs 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.

Fuel Inventory

Fuel inventory includes the average costs of oil, coal, natural gas, and emission allowances. Fuel is charged to inventory when purchased and then expensed as used. Emission allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Stock Options

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

For pro forma purposes, the Company generally recognizes stock option expense on a straight-line basis over the vesting period. Stock options granted to employees who are eligible for retirement are expensed at the grant date.

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

Net Income	As Reported	Options Impact	Pro Forma
		(in millions)	
2005	**$715**	**$(3)**	**$712**
2004	$658	(3)	$655
2003	$631	(4)	$627

The estimated fair value of stock options granted in 2005, 2004, and 2003 was derived using the Black-Scholes stock option pricing model. The following table shows the assumptions and the weighted average fair values of stock options.

	2005	2004	2003
Interest rate	**3.90%**	3.10%	2.70%
Average expected life of stock options (in years)	**5.0**	5.0	4.3
Expected volatility of common stock	**17.90%**	19.60%	23.60%
Expected annual dividends on common stock	**$1.43**	$1.40	$1.37
Weighted average fair value of stock options granted	**$3.90**	$3.29	$3.59

See Note 8 for additional information.

Financial Instruments

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

through current period income and are recorded on a net basis in the statements of income.

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

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

	Carrying Amount	Fair Value
Long-term debt:	(in millions)	
2005	**$5,227**	**$5,195**
2004	$5,055	$5,125

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

Comprehensive Income

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

Variable Interest Entities

The primary beneficiary of a variable interest entity must consolidate the related assets and liabilities. The Company has established certain wholly-owned trusts to issue preferred securities. However, the Company is not the primary beneficiary of the trusts. Therefore, the investments in these trusts are reflected as Other Investments, and the related loans from the trusts are reflected as Long-Term Debt Payable to Affiliated Trusts on the balance sheets. See Note 6 under "Mandatorily Redeemable Preferred Securities/Long-Term Debt Payable to Affiliated Trusts" for additional information.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. The plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). In 2005, the plan was amended to provide an additional monthly supplement to certain retirees. No contributions to the plan are expected for the year ending December 31, 2006. The Company also provides certain non-qualified benefit plans for a selected group of management and highly compensated employees. Benefits under these non-qualified plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees. The Company funds related trusts to the extent required by the Georgia PSC and the FERC. For the year ended December 31, 2006, such contributions are expected to total approximately $18.4 million. The measurement date for plan assets and obligations is September 30 for each year presented.

Pension Plans

The accumulated benefit obligation for the pension plans was $1.9 billion in 2005 and $1.7 billion in 2004. Changes during the year in the projected benefit obligations, accumulated benefit obligations, and the fair value of plan assets was as follows:

Projected Benefit Obligation	**2005**	2004
	(in millions)	
Balance at beginning of year	**$1,885**	$1,727
Service cost	**45**	42
Interest cost	**106**	101
Benefits paid	**(85)**	(85)
Plan amendments	**13**	1
Actuarial loss	**91**	99
Balance at end of year	**$2,055**	$1,885

	Plan Assets	
	2005	2004
	(in millions)	
Balance at beginning of year	**$2,181**	$2,055
Actual return on plan assets	**339**	207
Benefits paid	**(80)**	(81)
Balance at end of year	**$2,440**	$2,181

In 2005, the projected benefit obligations for the qualified and non-qualified pension plans were $1.945 billion and $110 million, respectively. All plan assets are related to the qualified plan.

Pension plan assets are managed and invested in accordance with all applicable requirements including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity, as described in the table below. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes.

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

	Plan Assets		
	Target	**2005**	2004
Domestic equity	36%	**40%**	36%
International equity	24	**24**	20
Fixed income	15	**17**	26
Real estate	15	**13**	10
Private equity	10	**6**	8
Total	100%	**100%**	100%

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

	2005	2004
	(in millions)	
Funded status	**$385**	$295
Unrecognized transition amount	**(4)**	(8)
Unrecognized prior service cost	**109**	108
Unrecognized net actuarial gain (loss)	**(54)**	21
Prepaid pension asset, net	**$436**	$416

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

	2005	2004
	(in millions)	
Prepaid pension asset	**$476**	$450
Employee benefit obligations	**(96)**	(89)
Other property and investments	**15**	19
Accumulated other comprehensive income	**41**	36
Prepaid pension asset, net	**$436**	$416

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

	2005	2004	2003
	(in millions)		
Service cost	**$ 45**	$ 42	$ 38
Interest cost	**106**	101	100
Expected return on plan assets	**(182)**	(180)	(179)
Recognized net (gain)/loss	**3**	(5)	(19)
Net amortization	**7**	7	6
Net pension (income)	**$(21)**	$(35)	$ (54)

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2005, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2006	$ 88
2007	91
2008	94
2009	97
2010	102
2011 to 2015	$607

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	
	2005	2004
	(in millions)	
Balance at beginning of year	**$726**	$723
Service cost	**10**	10
Interest cost	**41**	41
Benefits paid	**(32)**	(31)
Actuarial loss	**24**	42
Plan amendments	**-**	(59)
Balance at end of year	**$769**	$726

	Plan Assets	
	2005	2004
	(in millions)	
Balance at beginning of year	**$299**	$265
Actual return on plan assets	**38**	32
Employer contributions	**40**	33
Benefits paid	**(32)**	(31)
Balance at end of year	**$345**	$299

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

	Plan Assets		
	Target	**2005**	2004
Domestic equity	43%	**43%**	42%
International equity	21	**22**	23
Domestic fixed income	19	**19**	19
Global fixed income	11	**11**	11
Real estate	4	**3**	3
Private equity	2	**2**	2
Total	100%	**100%**	100%

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

	2005	2004
	(in millions)	
Funded status	**$(424)**	$(428)
Unrecognized transition obligation	**70**	78
Unrecognized prior service cost	**25**	27
Unrecognized net loss	**203**	203
Fourth quarter contributions	**21**	15
Employee benefit obligations recognized in the balance sheets	**$(105)**	$(105)

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

	2005	2004	2003
	(in millions)		
Service cost	**$10**	$ 10	$ 9
Interest cost	**41**	41	40
Expected return on plan assets	**(22)**	(25)	(24)
Net amortization	**18**	18	16
Net postretirement cost	**$47**	$ 44	$ 41

In the third quarter 2004, the Company prospectively adopted FASB Staff Position (FSP) 106-2, Accounting and Disclosure Requirements related to the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (Medicare Act). The Medicare Act provides a 28 percent prescription drug subsidy for Medicare eligible retirees. FSP 106-2 requires recognition of the impacts of the Medicare Act in the accumulated postretirement benefit obligation (APBO) and future cost of service for postretirement medical plans. The effect of the subsidy reduced the Company's expenses for the six months ended December 31, 2004 and for the year ended December 31, 2005 by approximately $5 million and $10 million, respectively, and is expected to have a similar impact on future expenses.

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the accumulated benefit obligation for the postretirement plans. Estimated benefit payments are reduced by drug

subsidy receipts expected as a result of the Medicare Act as follows:

	Benefit Payments	Subsidy Receipts	Total
	(in millions)		
2006	$ 37	$ (3)	$ 34
2007	39	(4)	35
2008	42	(4)	38
2009	46	(4)	42
2010	50	(5)	45
2011 to 2015	280	(34)	246

Actuarial Assumptions

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

	2005	2004	2003
Discount	**5.50%**	5.75%	6.00%
Annual salary increase	**3.00**	3.50	3.75
Long-term return on plan assets	**8.50**	8.50	8.50

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

An additional assumption used in measuring the APBO was a weighted average medical care cost trend rate of 10.25 percent for 2005, decreasing gradually to 4.75 percent through the year 2014, 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, 2005, as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$70	$62
Service and interest costs	5	4

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides a 75 percent matching contribution up to 6 percent of an employee's base salary. Total matching contributions made to the plan for the years 2005, 2004, and 2003 were $19 million, $18 million, and $18 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, and citizen enforcement of environmental requirements such as opacity and other air quality standards, 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 pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S District Court for the Northern District of Georgia against the Company and Alabama Power, alleging that the Company and Alabama Power had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws with respect to certain coal-fired generating facilities. Through subsequent amendments and other legal proceedings, the EPA added Savannah Electric as a defendant to the original action and filed a separate action against Alabama Power after it was dismissed from the original action. In these lawsuits, the

EPA alleges that NSR violations occurred at eight coal-fired generating facilities, including the Company's Plants Bowen and Scherer. The civil action requests penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. On June 3, 2005, the U.S. District for the Northern District of Alabama issued a decision in favor of Alabama Power on two primary legal issues in the case; however, the decision does not resolve the case, nor does it address other legal issues associated with the EPA's allegations. In accordance with a separate court order, Alabama Power and the EPA are currently participating in mediation with respect to the EPA's claims. The action against the Company and Savannah Electric has been administratively closed since the spring of 2001, and none of the parties has sought to reopen the case.

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $32,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in this case could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

Plant Wansley Environmental Litigation

In December 2002, the Sierra Club, Physicians for Social Responsibility, Georgia Forestwatch, and one individual filed a civil suit in the U.S. District Court for the Northern District of Georgia against the Company for alleged violations of the Clean Air Act at four of the units at Plant Wansley. 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. The liability phase of the case has concluded with the court ruling in favor of the Company in part and the plaintiffs in part. In March 2005, the U.S. Court of Appeals for the Eleventh Circuit accepted the Company's petition for review of the district court's order, and oral arguments were held on January 24, 2006. The district court case has been administratively closed pending that appeal. If necessary, the district court will hold a separate trial which will address civil penalties and possible injunctive relief requested by the plaintiffs. The ultimate outcome of this matter cannot currently be determined; however, an adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

Environmental Remediation

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. In 1995, the EPA designated the Company and four other unrelated entities as potentially responsible parties at a site in Brunswick, Georgia that is listed on the federal National Priorities List. As of December 31, 2005, the Company had recorded approximately $6 million in cumulative expenses associated with the Company's agreed-upon share of the removal and remedial investigation and feasibility study costs for the Brunswick site. Additional claims for recovery of natural resource damages at the site are anticipated. The Company has also recognized $36 million in cumulative expenses through December 31, 2005 for the assessment and anticipated cleanup of sites on the Georgia Hazardous Sites Inventory.

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 the Company'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.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates at market-based prices. The Company also has FERC authority to make short-term opportunity sales at market rates. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in that proceeding. In February 2005, Southern Company submitted responsive information. In February 2006, the FERC agreed to allow the parties to conduct settlement discussions. Any new market-based rate transactions in its retail service territory entered into after February 27, 2005 are subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. The impact of such sales through December 31, 2005 is not expected to exceed $4.9 million. The refund period covers 15 months. In the event that the FERC's default mitigation measures for entities that are found to have market power are ultimately applied, the Company may be required to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates. The final outcome of this matter will depend on the form in which the final methodology for assessing generation market power and mitigation rules may be ultimately adopted and cannot be determined at this time.

In addition, in May 2005, the FERC started an investigation to determine whether Southern Company satisfies the other three parts of the FERC's market-based rate analysis: transmission market power, barriers to entry, and affiliate abuse or reciprocal dealing. The FERC established a new refund period related to this expanded investigation. Any and all new market-based rate transactions both inside and outside Southern Company's retail service territory involving any Southern Company subsidiary, including the Company, will be subject to refund to the extent the FERC orders lower rates as a result of this new investigation, with the 15-month refund period beginning July 19, 2005. The impact of such sales through December 31, 2005 is not expected to exceed $10.9 million, of which $3.2 million relates to sales inside the retail service territory as discussed above. The FERC also directed that this expanded proceeding be held in abeyance pending the outcome of the proceeding on the IIC discussed below.

The Company believes that there is no meritorious basis for this proceeding and is vigorously defending itself in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in this proceeding, cannot now be determined.

Intercompany Interchange Contract

The Company's generation fleet in its retail service territory is operated under the IIC, as approved by the FERC. In May 2005, the FERC also initiated a new proceeding to examine (1) the provisions of the IIC among Alabama Power, the Company, Gulf Power, Mississippi Power, Savannah Electric, Southern Power, and SCS, as agent, under the terms of which the power pool of Southern Company is operated, and, in particular, the propriety of the continued inclusion of Southern Power as a party to the IIC, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining Southern Power as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of Southern Power, the FERC authorized Southern Power's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct. The FERC order directs that the administrative law judge who presided over the McIntosh PPA proceeding involving an approval of PPAs between Southern Power and the Company and Savannah Electric, be assigned to preside over the hearing in this proceeding and that the testimony and exhibits presented in that proceeding be preserved to the extent appropriate. Hearings are scheduled for September 2006. Effective July 19, 2005, revenues from transactions under the IIC involving any Southern Company subsidiaries, including the Company, are subject to refund to the extent the FERC orders any changes to the IIC.

The Company believes that there is no meritorious basis for this proceeding and is vigorously defending itself in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in this proceeding, cannot now be determined.

Generation Interconnection Agreements

In July 2003, the FERC issued its final rule on the standardization of generation interconnection agreements and procedures (Order 2003). Order 2003 shifts much of the financial burden of new transmission investment from the generator to the transmission provider. The FERC has indicated that Order 2003, which was effective January 20, 2004, is to be applied prospectively to interconnection

agreements. Subsidiaries of Tenaska, Inc., as counterparties to previously executed interconnection agreements with the Company and another Southern Company subsidiary, have filed complaints at the FERC requesting that the FERC modify the agreements and that the Company refund a total of $7.9 million previously paid for interconnection facilities, with interest. The Company has opposed such relief and the proceedings are still pending. The impact of Order 2003 and its subsequent rehearings on the Company and the final results of these matters cannot be determined at this time.

Race Discrimination Litigation

In July 2000, a lawsuit alleging race discrimination was filed by three of the Company's employees against the Company, Southern Company, and SCS in the Superior Court of Fulton County, Georgia. Shortly thereafter, the lawsuit was removed to the U.S. District Court for the Northern District of Georgia and amended to add four more plaintiffs. The lawsuit also raised claims on behalf of a purported class. The plaintiffs sought compensatory and punitive damages in an unspecified amount, as well as injunctive relief.

Following various court decisions in favor of the defendants and subsequent appeals by the plaintiffs, on July 13, 2005, the plaintiffs filed a petition for writ of certiorari to the U.S. Supreme Court. On October 17, 2005, the petition was denied. This matter is now concluded.

Right of Way Litigation

Southern Company and certain of its subsidiaries, including the Company, Gulf Power, Mississippi Power, and Southern Telecom, have been named as defendants in numerous lawsuits brought by landowners since 2001. 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 exceed the easements or other property rights held by defendants. The plaintiffs assert claims for, among other things, trespass and unjust enrichment, and seek compensatory and punitive damages and injunctive relief. Management believes that the Company has complied with applicable laws and that the plaintiffs' claims are without merit.

In January 2005, the Superior Court of Decatur County, Georgia granted partial summary judgment in a lawsuit brought by landowners against the Company based on the plaintiffs' declaratory judgment claim that the easements do not permit general telecommunications use. The Company appealed this ruling to the Georgia Court of Appeals. The Georgia Court of Appeals reversed, in part, the court's order and remanded the case to the trial court for the determination of further issues. After the Court of Appeals' decision, the plaintiffs filed a motion for reconsideration, which was denied, and a petition for certiorari to the Georgia Supreme Court, which is currently pending. The question of damages and other liabilities or remedies issues with respect to this action, if any, will be decided at a future trial. In the event of an adverse verdict in the case, the Company could appeal both liability and damages or other relief granted. An adverse outcome in these matters could result in substantial judgments; however, the final outcome cannot now be determined.

In addition, in late 2001, certain subsidiaries of Southern Company, including Alabama Power, the Company, Gulf Power, Mississippi Power, Savannah Electric, and Southern Telecom, were named as defendants in a lawsuit brought by a telecommunications company that uses certain of the defendants' rights of way. This lawsuit alleges, among other things, that the defendants are contractually obligated to indemnify, defend, and hold harmless the telecommunications company from any liability that may be assessed against it in pending and future right of way litigation. The Company believes that the plaintiff's claims are without merit. In the fall of 2004, the trial court stayed the case until resolution of the underlying landowner litigation discussed above. In January 2005, the Georgia Court of Appeals dismissed the telecommunications company's appeal of the trial court's order for lack of jurisdiction. An adverse outcome in this matter, combined with an adverse outcome against the telecommunications company in one or more of the right of way lawsuits, could result in substantial judgments; however, the final outcome of these matters cannot now be determined.

Property Tax Dispute

The Company is involved in a significant property tax dispute with Monroe County, Georgia (Monroe County). The Monroe County Board of Tax Assessors (Monroe Board) has issued assessments reflecting substantial

increases in the ad valorem tax valuation of the Company's 22.95 percent ownership interest in Plant Scherer, which is located in Monroe County, for tax years 2003, 2004, and 2005. The Company is aggressively pursuing administrative appeals in Monroe County and has filed notices of arbitration for all three years. The appeals are currently stayed, pending the outcome of the litigation discussed below.

In November 2004, the Company filed suit, on its behalf, against the Monroe Board in the Superior Court of Monroe County. The Company contends that Monroe County acted without statutory authority in changing the valuation of a centrally assessed utility as established by the Revenue Commissioner of the State of Georgia and requests injunctive relief prohibiting Monroe County and the Monroe Board from unlawfully changing the value of Plant Scherer and ultimately collecting additional ad valorem taxes from the Company. On December 22, 2005, the court granted Monroe County's motion for summary judgment. The Company has filed an appeal of the Superior Court's decision to the Georgia Supreme Court.

If the Company is not successful in its administrative appeals and if Monroe County is successful in defending the litigation, the Company could be subject to total additional taxes through December 31, 2005 of up to $13 million, plus penalties and interest. The ultimate outcome of this matter cannot currently be determined.

Retail Regulatory Matters

Merger

On December 13, 2005, the Company and Savannah Electric entered into an Agreement and Plan of Merger. Savannah Electric will merge into the Company, with the Company continuing as the surviving corporation (the Merger). At the effective time of the Merger, each share of the Company's common stock will remain issued and outstanding; each share of the Company's preferred stock issued and outstanding will have been redeemed prior to the Merger; the issued and outstanding shares of Savannah Electric common stock, all of which are held by Southern Company, will be converted into the right to receive 1,500,000 shares of the Company's common stock; and each share of Savannah Electric preferred stock issued and outstanding immediately prior to the Merger will be converted into the right to receive one share of a new series of the Company's Class A Preferred Stock. The Merger must be approved by the preferred shareholders of Savannah Electric and is subject to the receipt of certain regulatory approvals from the FERC, the Georgia PSC, and the Federal Communications Commission. Pending regulatory approvals, the Merger is expected to be completed by July 2006. The Merger is not expected to have a material impact on the Company's financial statements.

While the Georgia PSC does not have specific approval authority over the merger of electric utilities, the Company and Savannah Electric have filed an application with the Georgia PSC with respect to certain approvals that will be necessary to effectively complete the Merger. In particular, the Company and Savannah Electric plan to seek the approval of the Georgia PSC with respect to the following matters:

- the transfer of Savannah Electric's generating facilities and certification of the generating facilities as the Company's assets;
- amendments to the Company's Integrated Resource Plan to add the current Savannah Electric's customers and generating facilities;
- the transfer of Savannah Electric's assigned service territory to the Company;
- adoption of the Company's service rules and regulations to the current Savannah Electric customers;
- new fuel rate and base rate schedules that would apply to the Company's sale of electricity to the current Savannah Electric customers;
- adoption of a "merger transition adjustment" rate that would be used to more closely align Savannah Electric's existing base rates to those of the Company and a "merger transition credit" rate that would credit the additional revenues collected from former Savannah Electric customers to the Company's existing customers; and
- the issuance of additional shares of the Company's common stock to Southern Company in exchange for Southern Company's shares of Savannah Electric common stock.

Rate Plans

Under the terms of the 2004 Retail Rate Plan, which the Georgia PSC approved in December 2004, the Company's earnings are evaluated against a retail return on common equity (ROE) range of 10.25 percent to 12.25 percent. Two-thirds of any earnings

above 12.25 percent will be applied to rate refunds, with the remaining one-third retained by the Company. Retail rates were increased by approximately $194 million and customer fees by approximately $9 million effective January 1, 2005 to cover the higher costs of purchased power; operating and maintenance expenses; environmental compliance; and continued investment in new generation, transmission, and distribution facilities to support growth and ensure reliability. In 2005, the Company recorded $2.7 million in revenue subject to refund related to earnings in excess of 12.25 percent retail ROE.

The Company is required to file a general rate case by July 1, 2007, in response to which the Georgia PSC would be expected to determine whether the rate order should be continued, modified, or discontinued. Until then, the Company may not file for a general base rate increase unless its projected retail ROE falls below 10.25 percent.

Under the 2001 Retail Rate Plan, retail rates were decreased by $118 million effective January 1, 2002. Under the terms of the 2001 Retail Rate Plan, earnings were evaluated against a retail ROE range of 10 percent to 12.95 percent. Two-thirds of any earnings above the 12.95 percent return were to be applied to rate refunds, with the remaining one-third retained by the Company. The Company's earnings in 2004, 2003, and 2002 were within the retail ROE range.

Under the 2001 Retail Rate Plan, the Company discontinued recording accelerated depreciation and amortization and began amortizing the accumulated balance equally over three years as a credit to expense beginning in 2002. Also, the 2001 Retail Rate Plan required the Company to recognize capacity and operating and maintenance costs related to new Georgia PSC-certified PPAs evenly in rates over a three-year period ended December 31, 2004.

Fuel Hedging Program

In 2003, the Georgia PSC approved an order allowing the Company to implement a natural gas and oil procurement and hedging program. This order allows the Company to use financial instruments to hedge price and commodity risk associated with these fuels. 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 the Company retaining 25 percent of the total net gains. In 2005, the Company had a total net gain of $64.1 million, of which the Company retained $16 million.

Fuel Cost Recovery

On May 17, 2005, the Georgia PSC approved the Company's request to increase customer fuel rates by approximately 9.5 percent to recover under recovered fuel costs of approximately $508 million existing as of May 31, 2005 over a four-year period that began June 1, 2005. Based on the order, a portion of the under recovered regulatory clause revenues was reclassified from current assets to deferred charges and other assets in the balance sheet. Under recovered fuel amounts for the periods subsequent to June 1, 2005 totaled $327.5 million through December 31, 2005. The Georgia PSC's order instructs that such amounts be reviewed semi-annually beginning February 2006. If the amount under or over recovered exceeds $50 million at the evaluation date, the Company would be required to file for a temporary fuel rate change. In addition, Savannah Electric's under recovered fuel costs totaled $77.7 million at December 31, 2005. In accordance with the Georgia PSC order, Savannah Electric was scheduled to file an additional request for a fuel cost recovery increase in January 2006. The Company has agreed with a Georgia PSC staff recommendation to forego the temporary fuel rate process, and Savannah Electric has postponed its scheduled filing. Instead, the Company and Savannah Electric will file a combined request in March 2006 to increase the Company's fuel cost recovery rate.

The case will seek approval of a fuel cost recovery rate based upon future fuel cost projections for the combined Company and Savannah Electric generating fleet as well as the under recovered fuel balances existing at June 30, 2006. The new fuel cost recovery rate would be billed beginning in July 2006 to all of the Company's customers, including the existing Savannah Electric customers. Under recovered amounts as of the date of the Merger will be paid by the appropriate customer groups.

In August 2005, the Georgia PSC initiated an investigation of Savannah Electric's fuel practices. In February 2006, an investigation of the Company's fuel

practices was initiated. The Company and Savannah Electric are responding to data requests and cooperating in the investigations. The final outcome of this matter cannot now be determined.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable cost and amounts billed in current regulated rates. Accordingly, any increase in the billing factor would have no significant effect on the Company's revenues or net income, but would increase annual cash flow.

Nuclear Performance Standards

Through December 2004, the Georgia PSC had adopted a three-year performance standard for the Company's nuclear generating units. The performance standard was 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. For the period 2002-2004, the Company's performance fell within the criteria prescribed by the Georgia PSC; there was no associated award or penalty. Effective January 1, 2005, the Georgia PSC discontinued the nuclear performance standard.

Plant McIntosh Construction Project

In December 2002 after a competitive bidding process, the Georgia PSC certified PPAs between Southern Power and the Company and Savannah Electric for capacity from Plant McIntosh Units 10 and 11, construction of which was completed in June 2005. In April 2003, Southern Power applied for FERC approval of these PPAs. In July 2003, the FERC accepted the PPAs to become effective June 1, 2005, subject to refund, and ordered that hearings be held. Intervenors opposed the FERC's acceptance of the PPAs, alleging that they did not meet the applicable standards for market-based rates between affiliates. To ensure the timely completion of the Plant McIntosh construction project and the availability of the units in the summer of 2005 for their retail customers, in May 2004, the Company and Savannah Electric requested the Georgia PSC to direct them to acquire the Plant McIntosh construction project. The Georgia PSC issued such an order and the transfer occurred on May 24, 2004 at a total cost of approximately $415 million, including approximately $14 million of transmission interconnection facilities. Subsequently, Southern Power filed a request to withdraw the PPAs and to terminate the ongoing FERC proceedings. In August 2004, the FERC issued a notice accepting the request to withdraw the PPAs and permitting such request to become effective by operation of law. However, the FERC made no determination on what additional steps may need to be taken with respect to testimony provided in the proceedings. See "FERC Matters – Intercompany Interchange Contract" herein for additional information.

In connection with the 2004 Retail Rate Plan, the Georgia PSC approved the transfer of the Plant McIntosh construction project at a total fair market value of approximately $385 million. This value reflected an approximate $16 million disallowance, of which $13 million was attributable to the Company, and reduced the Company's net income by approximately $8 million. The Georgia PSC also certified a total completion cost not to exceed $547 million for the project. In June 2005, Plant McIntosh Units 10 and 11 were placed into service at a total cost that did not exceed the certified amount. Under the 2004 Retail Rate Plan, the Plant McIntosh revenue requirements impact is being reflected in the Company's rates evenly over the three years ending 2007. See "Retail Regulatory Matters—Rate Plans" herein for additional information regarding the transfer of the Plant McIntosh construction project.

4. JOINT OWNERSHIP AGREEMENTS

The Company and an affiliate, Alabama Power, own equally all of the outstanding capital stock of SEGCO which owns electric generating units with a total rated capacity of 1,020 megawatts, as well as associated transmission facilities. The capacity of 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:

	2005	2004	2003
		(in millions)	
Energy	$54	$51	$55
Capacity	38	36	34
Total	$92	$87	$89

The Company 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 (MEAG), the city of Dalton, Georgia, Florida Power & Light Company, Jacksonville Electric Authority, and Gulf Power. Under these agreements, the Company has contracted to operate and maintain the plants as agent for the co-owners and 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 combustion- turbine common facilities and Plant McIntosh combined cycle units with Savannah Electric who operates the plants. The Company and Progress Energy Florida, Inc. jointly own a combustion turbine unit (Intercession City) operated by Progress Energy Florida, Inc.

At December 31, 2005, 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%	$3,311*	$1,809
Plant Hatch (nuclear)	50.1	935	492
Plant Wansley (coal)	53.5	395	172
Plant Scherer (coal)			
Units 1 and 2	8.4	115	56
Unit 3	75.0	562	270
Plant McIntosh CC (combined cycle)	83.9	436	7
Plant McIntosh Common Facilities (combustion-turbine)	75.0	27	5
Rocky Mountain (pumped storage)	25.4	169*	92
Intercession City (combustion-turbine)	33.3	12	2

*Investment includes write-offs

At December 31, 2005, the portion of total construction work in progress related to Plants Wansley, Scherer, and Rocky Mountain was $8.3 million, $0.5 million, and $0.1 million, respectively, primarily for environmental projects.

The Company's proportionate share of its plant operating expenses is included in the corresponding operating expenses in the statements of income.

5. INCOME TAXES

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

In 2004, in order to avoid the loss of certain federal income tax credits related to the production of synthetic fuel, Southern Company chose to defer certain

deductions otherwise available to the subsidiaries. The cash flow benefit associated with the utilization of the tax credits was allocated to the subsidiary that otherwise would have claimed the available deductions on a separate company basis without the deferral. This allocation concurrently reduced the tax benefit of the credits allocated to those subsidiaries that generated the credits. As the deferred expenses are deducted, the benefit of the tax credits will be repaid to the subsidiaries that generated the tax credits. The Company has recorded $10 million payable to these subsidiaries in Accumulated Deferred Income Taxes on the balance sheets at December 31, 2005.

The transfer of the Plant McIntosh construction project from Southern Power to the Company resulted in a deferred gain to Southern Power for federal income tax purposes. The Company will reimburse Southern Power for the remaining balance of the related deferred taxes of $5.3 million reflected in Southern Power's future taxable income. $3.7 million of this payable to Southern Power is included in Other Deferred Credits and $1.6 million is included in Affiliated Accounts Payable in the balance sheet at December 31, 2005.

The transfer of the Dahlberg, Wansley, and Franklin projects to Southern Power from the Company in 2001 and 2002 also resulted in a deferred gain for federal income tax purposes. Southern Power will reimburse the Company for the remaining balance of the related deferred taxes of $12.2 million reflected in the Company's future taxable income. $10.8 million of this receivable from Southern Power is included in Other Deferred Debits and $1.4 million is included in Affiliated Accounts Receivable in the balance sheet at December 31, 2005.

At December 31, 2005, tax-related regulatory assets were $501 million and tax-related regulatory liabilities were $159 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:

	2005	2004	2003
Total provision for income taxes:		(in millions)	
Federal:			
Current	**$173**	$116	$143
Deferred	**203**	221	181
	376	337	324
State:			
Current	**26**	12	24
Deferred	**29**	30	16
Deferred investment tax credits	**-**	-	2
Total	**$431**	$379	$366

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:

	2005	2004
	(in millions)	
Deferred tax liabilities:		
Accelerated depreciation	**$2,177**	$2,050
Property basis differences	**558**	577
Employee benefit obligations	**163**	149
Fuel clause under recovery	**305**	141
Premium on reacquired debt	**69**	72
Storm damage reserve	**13**	6
Other	**74**	81
Total	**3,359**	3,076
Deferred tax assets:		
Federal effect of state deferred taxes	**116**	106
Other property basis differences	**139**	147
Other deferred costs	**126**	94
Employee benefit obligations	**51**	55
Other comprehensive income	**23**	22
Unbilled revenue	**13**	11
Other	**33**	19
Total	**501**	454
Total deferred tax liabilities, net	**2,858**	2,622
Portion included in current (liabilities) assets, net	**(128)**	(66)
Accumulated deferred income taxes in the balance sheets	**$2,730**	$2,556

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 2005, $12 million in 2004, and $15 million in 2003. At December 31, 2005, all investment tax credits available to reduce federal income taxes payable had been utilized.

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

	2005	2004	2003
Federal statutory rate	35%	35%	35%
State income tax, net of federal deduction	3	3	3
Non-deductible book depreciation	1	1	1
Other	(1)	(2)	(2)
Effective income tax rate	38%	37%	37%

6. FINANCING

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

The Company has formed certain wholly owned trust subsidiaries for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the Company through the issuance of junior subordinated notes totaling $969 million, which constitute substantially all of the assets of the trusts and are reflected in the balance sheets as Long-Term Debt Payable to Affiliated Trusts. The Company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the respective trusts' payment obligations with respect to these securities. At December 31, 2005, preferred securities of $940 million were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for these trusts and the related securities.

Securities Due Within One Year

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

	2005	2004
	(in millions)	
Capital lease	$ 3	$ 2
Senior notes	150	450
Preferred stock	15	-
Total	$168	$452

Serial maturities through 2010 applicable to total long-term debt and preferred stock are as follows: $168 million in 2006; $303 million in 2007; $3 million in 2008; $278 million in 2009; and $4 million in 2010.

Pollution Control Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such 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, 2005 was $1.7 billion.

Senior Notes

The Company issued a total of $625 million of unsecured senior notes in 2005. The proceeds of these issues were used to redeem or repay at maturity long-term debt, to repay short-term indebtedness, and for other general corporate purposes. At December 31, 2005 and 2004, the Company had $2.6 billion and $2.4 billion of senior notes outstanding, respectively. These senior notes are subordinate to all secured debt of the Company.

Capital Leases

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, 2005 and 2004, the Company had a capitalized lease obligation for its corporate headquarters

building of $74 million and $77 million, respectively, with an interest rate of 8.1 percent. For ratemaking purposes, the Georgia PSC 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 Georgia PSC. See Note 1 under "Regulatory Assets and Liabilities."

Bank Credit Arrangements

At the beginning of 2006, the Company had credit arrangements with banks totaling $780 million, of which $778 million was unused. Of these facilities, $70 million expires at various times throughout 2006; $350 million expires in 2007, with the remaining $360 million expiring in 2010. The facilities that expire in 2006 provide the option of converting borrowings into a two-year term loan. The Company expects to renew its facilities, as needed, prior to expiration. The agreements contain stated borrowing rates. All the agreements require payment of commitment fees based on the unused portion 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. A fee is also paid to the agent bank.

The credit arrangements contain covenants that limit the level of indebtedness to capitalization to 65 percent, as defined in the arrangements. For purposes of these definitions, indebtedness excludes the long-term debt payable to affiliated trusts. In addition, the credit arrangements contain cross default provisions that would trigger an event of default if the Company defaulted on other indebtedness above a specified threshold. At December 31, 2005, the Company was in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowings.

The $778 million 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, 2005 was $106 million. In addition, the Company borrows under a commercial paper program and an extendible commercial note program. The amount of commercial paper outstanding at December 31, 2005 was $268 million. The amount of commercial paper outstanding at December 31, 2004 was $208 million. There were no outstanding extendible commercial notes at December 31, 2005. Commercial paper is included in notes payable on the balance sheets.

During 2005, the peak amount of short-term debt outstanding was $549 million and the average amount outstanding was $242 million. The average annual interest rate on short-term debt in 2005 was 3.20 percent.

Financial Instruments

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. See Note 3 under "Retail Regulatory Matters – Fuel Hedging Program" for information on the Company's fuel hedging program. The Company also enters into hedges of forward electricity sales. There was no material ineffectiveness recorded in earnings in 2005, 2004, and 2003.

At December 31, 2005, the fair value of derivative energy contracts was reflected in the financial statements as follows:

	Amounts (in thousands)
Regulatory liabilities, net	$26,643
Other comprehensive income	-
Net income	(81)
Total fair value	$26,562

The fair value gain or loss for hedges that are recoverable through the regulatory fuel clauses are recorded in regulatory assets and liabilities and are recognized in earnings at the same time the hedged items affect earnings. The Company has energy-related hedges in place up to and including 2008.

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

addition to interest rate swaps, the Company has also entered into certain options agreements that effectively cap its interest rate exposure in return for payment of a premium. In some cases, costless collars have been used that effectively establish a floor and a ceiling to interest rate expense.

At December 31, 2005, the Company had $1.0 billion notional amounts of interest derivatives accounted for as cash flow hedges outstanding with net fair value gains as follows:

Maturity	Weighted Average Fixed Rate Paid	Notional Amount	Fair Value Gain / (Loss)
		(in millions)	
2007	2.67%	$300	$ 2.4
2006-2007	2.09% -3.85%*	$400	$ 1.2
2037	4.58% -5.75%**	$300	$(1.1)

*Series of interest rate caps and collars (showing the lowest floor and highest cap) with variable rate based on one-month LIBOR
**Interest rate collar

The fair value gain or loss for cash flow hedges is recorded in other comprehensive income and is reclassified into earnings at the same time the hedged items affect earnings. In 2005, 2004, and 2003, the Company settled gains (losses) totaling $0.9 million, $(12.4) million, and $(11.3) million, respectively, upon termination of certain interest derivatives at the same time it issued debt. For the years 2005, 2004, and 2003, approximately $1.9 million, $3.9 million, and $3.4 million, respectively, of pre-tax losses were reclassified from other comprehensive income to interest expense. For 2006, pre-tax losses of approximately $0.5 million are expected to be reclassified from other comprehensive income to interest expense. The Company has gains/losses that are being amortized through 2017.

7. COMMITMENTS

Construction Program

The Company currently estimates property additions to be approximately $1.3 billion, $1.4 billion, and $1.3 billion in 2006, 2007, and 2008, respectively. These amounts include $44 million, $28 million, and $14 million in 2006, 2007, and 2008, respectively, for construction expenditures related to contractual purchase commitments for uranium and nuclear fuel conversion, enrichment, and fabrication services included under "Fuel Commitments" herein. 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, changes in FERC rules and transmission regulations, 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, 2005, significant purchase commitments were outstanding in connection with the construction program.

The Company completed construction of Plant McIntosh Units 10 and 11 in June 2005 and has no other generating plants currently under construction. Construction related to new transmission and distribution facilities and capital improvements to existing generation, transmission and distribution facilities, including those needed to meet environmental standards, is ongoing.

Long-Term Service Agreements

The Company and Savannah Electric have entered into a Long-Term Service Agreement (LTSA) with General Electric (GE) for the purpose of securing maintenance support for the combustion turbines at the Plant McIntosh combined cycle facility. In summary, the LTSA stipulates that GE will perform all planned inspections on the covered equipment, which includes the cost of all labor and materials. GE is also obligated to cover the costs of unplanned maintenance on the covered equipment subject to a limit specified in each contract.

In general, this LTSA is in effect through two major inspection cycles per unit. Scheduled payments to GE are made at various intervals based on actual operating hours of the respective units. Total payments to GE under this agreement are currently estimated at $186 million over the remaining term of the agreement, which may range up to 30 years. However, the LTSA contains various cancellation provisions at the option of the Company.

The Company has also entered into an LTSA with GE through 2014 for neutron monitoring system parts and electronics at Plant Hatch. Total remaining payments to GE under this agreement are currently estimated at $13.1 million. The contract contains

cancellation provisions at the option of the Company.

Payments made to GE prior to the performance of any work are recorded as a prepayment in the balance sheets. Work performed by GE is capitalized or charged to expense as appropriate net of any joint owner billings, based on the nature of the work.

Fuel Commitments

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement of fossil and nuclear fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Coal commitments include forward contract purchases for sulfur dioxide emission allowances. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery. Amounts included in the chart below represent estimates based on New York Mercantile Exchange future prices at December 31, 2005.

Total estimated minimum long-term obligations at December 31, 2005 were as follows:

	Commitments		
	Natural Gas	Coal	Nuclear Fuel
		(in millions)	
2006	$577	$1,579	$ 44
2007	325	1,313	28
2008	200	907	14
2009	257	422	11
2010	254	272	14
2011 and thereafter	2,047	40	64
Total	$3,660	$4,533	$175

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

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other Southern Company retail operating companies, Southern Power, and Southern Company Gas. Under these agreements, each of the retail operating companies, Southern Power, and Southern Company Gas may be jointly and severally liable. The creditworthiness of Southern Power and Southern Company Gas is currently inferior to the creditworthiness of the retail operating companies. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the retail 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 Company Gas as a contracting party under these agreements.

Purchased Power Commitments

The Company has commitments regarding a portion of a 5 percent interest in Plant Vogtle owned by 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 $54 million, $55 million, and $57 million in 2005, 2004, and 2003, respectively. The current projected Plant Vogtle capacity payments are:

	Capacity Payments
	(in millions)
2006	$ 53
2007	52
2008	54
2009	54
2010	54
2011 and thereafter	261
Total	$528

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 at the time of the disallowance was written off.

The Company has entered into other various long-term commitments for the purchase of electricity. Estimated total long-term obligations under these

commitments at December 31, 2005 were as follows:

	Commitments	
	Affiliated	Non-Affiliated
	(in millions)	
2006	$205	$85
2007	205	86
2008	205	87
2009	205	68
2010	112	66
2011 and thereafter	455	278
Total	$1,387	$670

Operating Leases

The Company has entered into various operating leases with various terms and expiration dates. Rental expenses related to these operating leases totaled $38 million for 2005, $38 million for 2004, and $36 million for 2003.

At December 31, 2005, estimated minimum lease payments for these noncancelable operating leases were as follows:

	Minimum Lease Payments		
	Rail Cars	Other	Total
		(in millions)	
2006	$ 17	$ 17	$ 34
2007	17	14	31
2008	16	11	27
2009	15	9	24
2010	14	6	20
2011 and thereafter	48	10	58
Total	$127	$67	$194

In addition to the rental commitments above, the Company has obligations upon expiration of certain rail car leases with respect to the residual value of the leased property. These leases expire in 2011 and the Company's maximum obligation is $68 million. 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 rail car lease obligations is shared with the joint owners of plants Scherer and Wansley. Rental expenses related to the rail car leases are fully recoverable through the fuel cost recovery clause as ordered by the Georgia PSC.

Guarantees

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. Alabama Power has also guaranteed $50 million in senior notes issued by SEGCO. The Company has agreed to reimburse Alabama Power for the pro rata portion of such obligations corresponding to the Company'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.

8. STOCK OPTION PLAN

Southern Company provides non-qualified stock options to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2005, 1,551 current and former employees of the Company participated in the stock option plan. The maximum number of shares of Southern Company common stock that may be issued under this plan may not exceed 55 million. The prices of options granted to date have been at the fair market value of the shares on the dates of grant. Options granted to date become exercisable pro rata over a maximum period of three years from the date of grant. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the stock option plan. Activity from 2003 to 2005 for the options granted

to the Company's employees under the stock option plan is summarized below:

	Shares Subject To Option	Average Option Price Per Share
Balance at December 31, 2002	7,178,597	$19.73
Options granted	1,455,517	27.98
Options canceled	(54,860)	25.47
Options exercised	(1,428,273)	16.92
Balance at December 31, 2003	7,150,981	21.92
Options granted	1,434,915	29.50
Options canceled	(6,371)	25.99
Options exercised	(1,450,309)	18.25
Balance at December 31, 2004	**7,129,216**	**24.19**
Options granted	**1,427,618**	**32.71**
Options canceled	**(12,910)**	**23.75**
Options exercised	**(1,838,033)**	**21.23**
Balance at December 31, 2005	**6,705,891**	**$26.82**

Options exercisable:	
At December 31, 2003	3,956,234
At December 31, 2004	4,304,091
At December 31, 2005	**3,989,722**

The following table summarizes information about options outstanding at December 31, 2005:

	Dollar Price Range of Options		
	13-21	21-28	28-35
Outstanding:			
Shares (in thousands)	991	2,922	2,794
Average remaining life (in years)	4.2	6.0	8.5
Average exercise price	$17.25	$25.94	$31.13
Exercisable:			
Shares (in thousands)	991	2,496	503
Average exercise price	$17.25	$25.59	$29.75

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act, the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the Company's nuclear power plants. The Act provides funds up to $10.76 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 $101 million per incident for each licensed reactor it operates but not more than an aggregate of $15 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 $203 million per incident but not more than an aggregate of $30 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 up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. The Company purchases the maximum limit allowed by NEIL 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 NEIL policies would be $48 million.

Following the terrorist attacks of September 2001, both ANI and NEIL confirmed that terrorist acts against commercial nuclear power plants would, subject to the normal policy limits, be covered under their insurance. Both companies, however, revised their policy terms on

a prospective basis to include an industry aggregate for all "non-certified" terrorist acts i.e., acts that are not certified acts of terrorism pursuant to the Terrorism Risk Insurance Act of 2002, which was renewed in 2005. The aggregate for all NEIL policies, which applies to non-certified property claims stemming from terrorism within a 12-month duration, is $3.24 billion plus any amounts available through reinsurance or indemnity from an outside source. The non-certified ANI nuclear liability cap is a $300 million shared industry aggregate during the normal ANI policy period.

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

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

10. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2005 and 2004 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred Stock
		(in millions)	
March 2005	**$1,370**	**$286**	**$142**
June 2005	**1,459**	**311**	**158**
September 2005	**2,219**	**626**	**355**
December 2005	**1,586**	**165**	**60**
March 2004	$1,199	$285	$144
June 2004	1,353	322	156
September 2004	1,582	486	287
December 2004	1,237	166	71

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

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SELECTED FINANCIAL AND OPERATING DATA 2001-2005

Georgia Power Company 2005 Annual Report

	2005	2004	2003	2002	2001
Operating Revenues (in thousands)	**$6,634,203**	$5,370,808	$4,913,507	$4,822,460	$4,965,794
Net Income after Dividends on Preferred Stock (in thousands)	**$714,999**	$658,001	$630,577	$617,629	$610,335
Cash Dividends on Common Stock (in thousands)	**$556,100**	$565,500	$565,800	$542,900	$527,300
Return on Average Common Equity (percent)	**14.15**	13.95	14.05	13.99	14.12
Total Assets (in thousands)	**$17,047,783**	$15,822,338	$14,850,754	$14,342,656	$14,447,973
Gross Property Additions (in thousands)	**$906,248**	$1,126,064	$742,810	$883,968	$1,389,751
Capitalization (in thousands):					
Common stock equity	**$5,214,535**	$4,890,561	$4,540,211	$4,434,447	$4,397,485
Preferred stock	**-**	14,609	14,569	14,569	14,569
Mandatorily redeemable preferred securities	**-**	-	940,000	940,000	789,250
Long-term debt payable to affiliated trusts	**969,073**	969,073	-	-	-
Long-term debt	**4,179,218**	3,709,852	3,762,333	3,109,619	2,961,726
Total (excluding amounts due within one year)	**$10,362,826**	$9,584,095	$9,257,113	$8,498,635	$8,163,030
Capitalization Ratios (percent):					
Common stock equity	**50.3**	51.0	49.0	52.2	53.9
Preferred stock	**-**	0.2	0.2	0.2	0.2
Mandatorily redeemable preferred securities	**-**	-	10.2	11.1	9.6
Long-term debt payable to affiliated trusts	**9.4**	10.1	-	-	-
Long-term debt	**40.3**	38.7	40.6	36.5	36.3
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Security Ratings:					
Preferred Stock -					
Moody's	**Baa1**	Baa1	Baa1	Baa1	Baa1
Standard and Poor's	**BBB+**	BBB+	BBB+	BBB+	BBB+
Fitch	**A**	A	A	A	A
Unsecured Long-Term Debt -					
Moody's	**A2**	A2	A2	A2	A2
Standard and Poor's	**A**	A	A	A	A
Fitch	**A+**	A+	A+	A+	A+
Customers (year-end):					
Residential	**1,832,520**	1,801,426	1,768,662	1,734,430	1,698,407
Commercial	**270,373**	265,543	258,276	250,993	244,674
Industrial	**8,206**	7,676	7,899	8,240	8,046
Other	**3,536**	3,482	3,434	3,328	3,239
Total	**2,114,635**	2,078,127	2,038,271	1,996,991	1,954,366
Employees (year-end)	**8,713**	8,731	8,714	8,837	9,048

N/A = Not Applicable.

SELECTED FINANCIAL AND OPERATING DATA 2001-2005 (continued)
Georgia Power Company 2005 Annual Report

	2005	2004	2003	2002	2001
Operating Revenues (in thousands):					
Residential	**$ 2,024,204**	$1,736,072	$1,583,082	$1,600,438	$1,507,031
Commercial	**2,206,252**	1,812,096	1,661,054	1,631,130	1,682,918
Industrial	**1,351,731**	1,172,936	1,012,267	1,004,288	1,106,420
Other	**60,625**	55,881	53,569	52,241	52,943
Total retail	**5,642,812**	4,776,985	4,309,972	4,288,097	4,349,312
Sales for resale - non-affiliates	**519,673**	246,545	259,376	270,678	366,085
Sales for resale - affiliates	**264,989**	166,245	174,855	98,323	99,411
Total revenues from sales of electricity	**6,427,474**	5,189,775	4,744,203	4,657,098	4,814,808
Other revenues	**206,729**	181,033	169,304	165,362	150,986
Total	**$6,634,203**	$5,370,808	$4,913,507	$4,822,460	$4,965,794
Kilowatt-Hour Sales (in thousands):					
Residential	**23,585,115**	22,930,372	21,778,582	22,144,559	20,119,080
Commercial	**29,768,402**	28,014,357	26,940,572	26,954,922	26,493,255
Industrial	**25,027,371**	26,357,271	25,703,421	25,739,785	25,349,477
Other	**601,330**	602,202	595,742	593,202	583,007
Total retail	**78,982,218**	77,904,202	75,018,317	75,432,468	72,544,819
Sales for resale - non-affiliates	**11,234,527**	5,969,983	8,835,804	8,069,375	8,110,096
Sales for resale - affiliates	**4,854,914**	4,782,873	5,844,196	3,962,559	3,133,485
Total	**95,071,659**	88,657,058	89,698,317	87,464,402	83,788,400
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**8.58**	7.57	7.27	7.23	7.49
Commercial	**7.41**	6.47	6.17	6.05	6.35
Industrial	**5.40**	4.45	3.94	3.90	4.36
Total retail	**7.14**	6.13	5.75	5.68	6.00
Sales for resale	**4.88**	3.84	2.96	3.07	4.14
Total sales	**6.76**	5.85	5.29	5.32	5.75
Residential Average Annual Kilowatt-Hour Use Per Customer	**12,974**	12,838	12,421	12,867	11,933
Residential Average Annual Revenue Per Customer	**$1,113**	$972	$903	$930	$894
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**15,097**	13,978	13,980	14,059	14,474
Maximum Peak-Hour Demand (megawatts):					
Winter	**13,501**	12,208	13,153	11,873	11,977
Summer	**15,953**	15,180	14,826	14,597	14,294
Annual Load Factor (percent)	**59.7**	61.5	61.0	60.4	61.7
Plant Availability (percent):					
Fossil-steam	**90.7**	90.3	87.6	80.9	88.5
Nuclear	**89.3**	94.8	94.2	88.8	94.4
Source of Energy Supply (percent):					
Coal	**60.8**	57.9	58.6	59.5	58.5
Nuclear	**15.1**	17.3	16.8	16.2	18.1
Hydro	**1.9**	1.5	2.1	0.9	1.1
Oil and gas	**2.9**	0.1	0.3	0.3	0.4
Purchased power -					
From non-affiliates	**5.7**	7.0	7.5	6.3	7.8
From affiliates	**13.6**	16.2	14.7	16.8	14.1
Total	**100.0**	100.0	100.0	100.0	100.0

DIRECTORS AND OFFICERS
Georgia Power Company 2005 Annual Report

Directors

Juanita Powell Baranco
Executive Vice President
Baranco Acura
(Resigned effective 2/21/2006)

Gus H. Bell, III – *Nominee*
Chairman, President and Chief Executive Officer
Hussey, Gay, Bell and DeYoung - A Bell Company

Robert L. Brown, Jr.
President and Chief Executive Officer
R. L. Brown & Associates, Inc.

Ronald D. Brown
President and Chief Executive Officer
Atlanta Life Financial Group

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

Michael D. Garrett
President and Chief Executive Officer
Georgia Power Company

David M. Ratcliffe
President and Chief Executive Officer
The Southern Company

D. Gary Thompson
Retired from
Wachovia Corporation

Richard W. Ussery
Retired from
Total System Services (TSYS)

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

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

Officers

Michael D. Garrett
President and Chief Executive Officer
Georgia Power Company

William C. Archer, III
Executive Vice President
External Affairs
(Retirement effective 3/19/2006)

Mickey A. Brown
Executive Vice President
Customer Service Organization

Cliff S. Thrasher
Executive Vice President, Chief Financial Officer
and Treasurer

Christopher C. Womack
Executive Vice President (Effective 3/11/2006)
External Affairs

Judy M. Anderson
Senior Vice President
Charitable Giving

Richard L. Holmes
Senior Vice President
Metro Region

E. Lamont Houston
Senior Vice President (Effective 1/14/2006)
Customer Service and Sales

Douglas E. Jones
Senior Vice President (Effective 3/11/2006)
Fossil and Hydro Generation

James H. Miller III
Senior Vice President and
General Counsel

Leslie R. Sibert
Vice President
Transmission

Gene L. Ussery
Vice President
Distribution

DIRECTORS AND OFFICERS

Georgia Power Company 2005 Annual Report

Michael K. Anderson
Vice President (Effective 1/14/2006)
Corporate Services

W. Craig Barrs
Vice President

Robert A. Bell
Vice President (Effective 2/15/2006)
Human Resources

Rebecca A. Blalock
Vice President
Information Technology

P. Mike Clanton
Vice President (Effective 1/14/2006)
Customer Service

Ann P. Daiss
Vice President, Comptroller and
Chief Accounting Officer (Effective 3/11/2006)

Walter Dukes
Region Vice President
East

A. Bryan Fletcher
Vice President
Supply Chain Management

J. Kevin Fletcher
Vice President
Community and Economic Development

Jeff G. Franklin
Region Vice President
Northwest

Oscar C. Harper IV
Vice President (Effective 2/11/2006)
Resource Planning and Nuclear Development

O. Ben Harris
Vice President
Land

W. Ron Hinson
Vice President, Comptroller and
Chief Accounting Officer (Resigned effective
3/11/2006)

Ed F. Holcombe
Vice President
Governmental and Regulatory Affairs

Charles H. Huling
Vice President
Environmental Affairs

Anne H. Kaiser
Vice President
Sales

Ellen N. Lindemann
Vice President (Resigned effective 2/1/2006)
Human Resources

Jacki W. Lowe
Region Vice President
West

Daniel M. Lowery
Corporate Secretary

Terri H. Lupo
Region Vice President
South

Frank J. McCloskey
Vice President
Diversity

Robert B. Morris
Assistant Comptroller and Assistant Secretary

James E. Sykes, Jr.
Region Vice President
Northeast

Mark K. Tate
Assistant Comptroller

Jeff L. Wallace
Vice President (Resigned effective 2/11/2006)
Planning and Utility Relations

Thomas J. Wicker
Region Vice President
Central

W. Tal Wright
Vice President
Corporate Communication

Wayne Boston
Assistant Secretary and
Assistant Treasurer

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

Profile
The Company produces and delivers electricity as an integrated utility to retail customers within the State of Georgia and to wholesale customers in the Southeast. The Company sells electricity to approximately 2.1 million customers within its service area of approximately 57,000 square miles. In 2005, retail energy sales accounted for 83 percent of the Company's total sales of 95.1 billion kilowatt-hours.

The Company is a wholly owned subsidiary of The Southern Company, which is the parent company of five retail operating companies and a wholesale generation subsidiary, as well as other direct and indirect subsidiaries. There is no established public trading market for the Company's common stock.

Trustee, Registrar and Interest Paying Agent
All series of Senior Notes and Trust Preferred Securities
JPMorgan Chase Bank, N.A.
Institutional Trust Services
4 New York Plaza, 15th Floor
New York, NY 10004

Number of Preferred Shareholders of record as of December 31, 2005, was 1,003.

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

Georgia Power Company
241 Ralph McGill Boulevard, N.E.
Atlanta, GA 30308-3374
(404) 506-6526

Auditors
Deloitte & Touche LLP
Suite 1500
191 Peachtree Street, N.E.
Atlanta, GA 30303

Legal Counsel
Troutman Sanders LLP
600 Peachtree Street, N.E.
Suite 5200
Atlanta, GA 30308

Please see page 2
of letter for
distribution of
copies.
Thank you

GEORGIA POWER
A SOUTHERN COMPANY

July 28, 2006

Docket Nos.: 50-321 50-424
50-366 50-425
72-36

NL-06-1486

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
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 2005.

2. A set of quarterly financial statements for the period ending June 30, 2006.

3. A one year projected Cash Flows Statement for period January 1, 2007, through December 31, 2007.

Should you have any questions in connection with our response, please contact me at (404) 506-7952 or Jan Miller at (404) 506-6690. This letter contains no NRC commitments.

Sincerely,

Robert A. Aubuchon

Enclosures

cc: Southern Nuclear Operating Company
Mr. J. T. Gasser, Executive Vice President
Mr. L. M. Stinson, Vice President, Plant Hatch
Mr. D. E. Grissette, Vice President, Plant Vogtle
Mr. D. R. Madison, General Manager – Plant Hatch
Mr. T. E. Tynan, General Manager – Plant Vogtle
RType: CHA02.004; CVC7000

U. S. Nuclear Regulatory Commission
Dr. W. D. Travers, Regional Administrator
Mr. C. Gratton, NRR Project Manager – Hatch
Mr. C. Gratton, NRR Project Manager – Vogtle
Mr. D. S. Simpkins, Senior Resident Inspector – Hatch
Mr. G. J. McCoy, Senior Resident Inspector – Vogtle

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2006	2005	2006	2005
OPERATING REVENUES:				
Retail sales	$1,420,762	$1,227,087	$2,687,718	$2,412,323
Sales for resale--				
Non-affiliates	132,557	126,000	265,921	238,852
Affiliates	85,674	54,743	120,616	80,374
Other revenues	59,745	51,358	111,932	98,069
Total operating revenues	1,698,738	1,459,188	3,186,187	2,829,618
OPERATING EXPENSES:				
Operation--				
Fuel	556,691	412,050	991,465	721,316
Purchased power--				
Non-affiliates	82,321	64,523	138,876	117,497
Affiliates	145,518	140,800	336,037	360,804
Other	226,256	223,471	444,976	425,550
Maintenance	119,876	123,575	239,176	240,225
Depreciation and amortization	117,590	124,999	235,447	248,099
Taxes other than income taxes	68,945	58,648	136,090	119,407
Total operating expenses	1,317,197	1,148,066	2,522,067	2,232,898
OPERATING INCOME	381,541	311,122	664,120	596,720
OTHER INCOME (EXPENSE):				
Allowance for equity funds used during construction	6,338	7,935	12,123	17,192
Interest income	199	31	515	502
Interest expense, net of amounts capitalized	(61,322)	(55,174)	(121,529)	(105,594)
Interest expense to affiliate trusts	(14,877)	(14,877)	(29,755)	(29,755)
Other income (expense), net	3,370	2,821	2,376	(21)
Total other income and (expense)	(66,292)	(59,264)	(136,270)	(117,676)
EARNINGS BEFORE INCOME TAXES	315,249	251,858	527,850	479,044
Income taxes	119,059	94,140	199,003	178,794
NET INCOME	196,190	157,718	328,847	300,250
DIVIDENDS ON PREFERRED STOCK	-	167	1,010	335
NET INCOME AFTER DIVIDENDS ON PREFERRED STOCK	$196,190	$157,551	$327,837	$299,915

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, 2006	At June 30, 2005
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$11,422	$9,294
Receivables --		
Customer accounts receivable	416,118	361,605
Unbilled revenues	176,184	168,392
Under recovered regulatory clause revenue	372,587	153,301
Other accounts and notes receivable	85,136	185,223
Affiliated companies	55,814	31,350
Accumulated provision for uncollectible accounts	(8,521)	(6,575)
Fossil fuel stock, at average cost	262,620	207,959
Materials and supplies, at average cost	352,866	286,446
Other	174,706	91,819
Total Current Assets	1,898,932	1,488,814
PROPERTY, PLANT AND EQUIPMENT:		
In service	19,957,393	19,327,416
Less accumulated provision for depreciation	7,775,166	7,392,744
	12,182,227	11,934,672
Nuclear fuel, at amortized cost	148,604	129,567
Construction work in progress	599,874	443,904
Total Property, Plant and Equipment	12,930,705	12,508,143
OTHER PROPERTY AND INVESTMENTS:		
Equity investments in unconsolidated subsidiaries	68,470	65,949
Nuclear decommissioning trusts	499,868	466,656
Other	70,800	64,472
Total Other Property and Investments	639,138	597,077
DEFERRED CHARGES AND OTHER ASSETS:		
Deferred charges related to income taxes	497,775	506,259
Prepaid pension costs	487,462	460,865
Unamortized debt issuance expense	84,515	88,638
Unamortized loss on reacquired debt	165,650	172,961
Deferred under recovered regulatory clause revenues	477,611	362,692
Other	255,106	170,698
Total Deferred Charges and Other Assets	1,968,119	1,762,113
TOTAL ASSETS	$17,436,894	$16,356,147

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

	At June 30, 2006	At June 30, 2005
LIABILITIES AND STOCKHOLDER'S EQUITY		
CURRENT LIABILITIES:		
Securities due within one year	$2,822	$402,603
Notes payable	657,559	379,902
Accounts payable --		
Affiliated companies	207,585	157,765
Other	292,313	248,786
Customer deposits	140,292	122,446
Taxes accrued		
Income taxes	313,302	183,985
Other	146,254	115,596
Interest accrued	74,533	78,595
Vacation pay accrued	45,692	44,179
Other	210,770	186,640
Total Current Liabilities	2,091,122	1,920,497
LONG-TERM DEBT	4,177,916	3,931,825
LONG-TERM DEBT PAYABLE TO AFFILIATED TRUSTS	969,073	969,073
DEFERRED CREDITS AND OTHER LIABILITIES:		
Accumulated deferred income taxes	2,693,006	2,598,783
Deferred credits related to income taxes	153,196	164,588
Accumulated deferred investment tax credits	281,581	293,872
Employee benefits provisions	379,656	346,916
Asset retirement obligations	647,003	520,298
Other	548,023	581,077
Total Deferred Credits and Other Liabilities	4,702,465	4,505,534
PREFERRED STOCK	-	14,609
COMMON STOCKHOLDER'S EQUITY:		
Common stock	344,250	344,250
Paid-in capital	2,880,563	2,589,121
Retained earnings	2,288,285	2,124,641
Accumulated other comprehensive income	(16,780)	(43,403)
Total Common Stockholder's Equity	5,496,318	5,014,609
TOTAL LIABILITIES AND STOCKHOLDER'S EQUITY	$17,436,894	$16,356,147

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

	FOR THE SIX MONTHS ENDED JUNE	
	2006	2005
OPERATING ACTIVITIES:		
Net income	$328,847	$300,250
Adjustments to reconcile net income to net cash provided by operating activities --		
Depreciation and amortization	276,048	292,447
Deferred income taxes and investment tax credits, net	13,433	89,724
Deferred expenses - affiliated	18,717	20,302
Allowance for funds used during construction	(12,123)	(17,192)
Pension, postretirement, and other employee benefits	(1,225)	5,318
Stock option expense	4,330	-
Other, net	8,729	(1,058)
Changes in certain current assets and liabilities --		
Receivables, net	(89,773)	(247,991)
Fossil fuel stock	(80,881)	(23,692)
Materials and supplies	(28,885)	(16,024)
Other current assets	49,999	14,055
Accounts payable	(128,890)	(59,236)
Taxes accrued	38,209	43,098
Other current liabilities	(76,833)	(42,595)
NET CASH PROVIDED FROM OPERATING ACTIVITIES	319,702	357,406
INVESTING ACTIVITIES:		
Gross property additions	(448,857)	(381,191)
Nuclear decommissioning trust fund purchases	(241,021)	(205,261)
Nuclear decommissioning trust fund sales	234,141	196,562
Cost of removal net of salvage	(10,658)	(10,359)
Other	(9,099)	(33,274)
NET CASH USED FOR INVESTING ACTIVITIES	(475,494)	(433,523)
FINANCING ACTIVITIES:		
Increase (decrease) in notes payable, net	389,817	171,669
Proceeds --		
Senior notes	-	375,000
Pollution control bonds	10,125	185,000
Capital contributions from parent company	232,328	100,000
Gross excess tax benefit of stock options	611	-
Redemptions --		
Pollution control bonds	(10,125)	(85,000)
Senior notes	(150,000)	(300,000)
Preferred stock	(14,569)	
Special deposits - redemption funds	-	(100,000)
Payment of preferred stock dividends	(12)	(211)
Payment of common stock dividends	(301,250)	(278,050)
Other	(347)	(16,494)
NET CASH PROVIDED FROM FINANCING ACTIVITIES	156,578	51,914
NET CHANGE IN CASH AND CASH EQUIVALENTS	786	(24,203)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	10,636	33,497
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$11,422	$9,294

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

GEORGIA POWER COMPANY
PROJECTED STATEMENT OF CASH FLOWS
2007 FORECAST
(Stated in Thousands of Dollars)

	2007 FORECAST
OPERATING ACTIVITIES	
Net income before preferred dividends	$831,346
Principal noncash items-	
Depreciation and amortization	622,394
Deferred income taxes, net	(26,943)
Allowance for equity funds used during construction	(71,263)
Pension, postretirement and other employee benefits	(16,032)
Other, net	230,590
Change in current assets & liabilities-	
Receivables	(36,755)
Inventories	10,331
Accounts payable	9,114
Other current assets and liabilities	95,611
NET CASH PROVIDED FROM OPERATING ACTIVITIES	1,648,393
INVESTING ACTIVITIES	
Gross property additions	(1,485,481)
Cost of removal, net of salvage	(34,695)
Allowance for equity funds used during construction	71,263
Other property and investments	(6,514)
NET CASH USED FOR INVESTING ACTIVITIES	(1,455,427)
FINANCING ACTIVITIES	
Increase in notes payable, net	(8,860)
Proceeds -	
Senior notes	675,000
Preferred stock	300,000
Capital contributions from parent company	126,619
Redemptions -	
Senior notes	(300,000)
Trust preferred securities	(300,000)
Capitalized leases	(2,550)
Stock Option Expense	12,399
Payment of preferred stock dividends	(3,370)
Payment of common stock dividends	(678,100)
Other	(13,702)
NET CASH USED FOR FINANCING ACTIVITIES	(192,564)
NET INC (DEC) IN CASH AND TEMPORARY CASH INVESTMENTS	$402
CASH AND TEMPORARY CASH INVESTMENTS AT BEG OF PERIOD	$15,750
CASH AND TEMPORARY CASH INVESTMENTS AT END OF PERIOD	$16,152

2005 *Annual Report*

GEORGIA POWER COMPANY

GEORGIA POWER

A SOUTHERN COMPANY

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Georgia Power Company 2005 Annual Report

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SUMMARY

	2005	2004	Percent Change
Financial Highlights *(in millions):*			
Operating revenues	**$6,634**	$5,371	23.5
Operating expenses	**$5,246**	$4,112	27.6
Net income after dividends on preferred stock	**$715**	$658	8.7
Operating Data:			
Kilowatt-hour sales *(in millions):*			
Retail	**78,982**	77,904	1.4
Sales for resale - non-affiliates	**11,235**	5,970	88.2
Sales for resale - affiliates	**4,855**	4,783	1.5
Total	**95,072**	88,657	7.2
Customers served at year-end *(in thousands)*	**2,115**	2,078	1.8
Peak-hour demand *(in megawatts)*	**15,953**	15,180	5.1
Capitalization Ratios *(percent):*			
Common stock equity	**50.3**	51.0	
Preferred stock	-	0.2	
Long-term debt payable to affiliated trusts	**9.4**	10.1	
Long-term debt	**40.3**	38.7	
Return on Average Common Equity *(percent)*	**14.15**	13.95	
Ratio of Earnings to Fixed Charges *(times)*	**4.92**	5.11	

LETTER TO INVESTORS

Georgia Power 2005 Annual Report

Georgia Power employees' extraordinary response after Hurricane Katrina and other storms hit the Gulf Coast last year is just one of the highlights in what was a remarkable year for the company.

Whether we're responding to storms in our own back yard or to the needs of fellow Southern Company employees and customers, it's extensive pre-planning and excellent execution that makes us so successful – it really is what we do best.

That's why we were honored when the Edison Electric Institute recognized us with its Emergency Assistance Award for the outstanding assistance we provided other utilities recovering last year from hurricanes Katrina, Rita and Wilma.

Our financial results mirror our operational success. With operating revenues of $6.6 billion, Georgia Power's 2005 earnings totaled $715 million, a $57 million, or 8.7 percent, increase from 2004. We earned a 14.15 percent total company return on average common equity during 2005. Georgia Power had net plant in service of $12.0 billion at the end of 2005, with total assets of $17.0 billion.

In 2005, we announced plans to merge one of our sister companies into Georgia Power; we made significant progress on the environmental front; and we overhauled our organizational structure to bring us even closer to our customers.

Late last year, the boards of directors of Southern Company, Savannah Electric and Georgia Power approved a plan to merge Savannah Electric into Georgia Power. This move should result in operational efficiencies and cost savings for Georgia Power.

Savannah Electric customers also are expected to benefit from Georgia Power's more diverse and cost-efficient generating fleet. We anticipate completing the merger by July 2006.

We continued our efforts last year to reduce the environmental impact of our operations by:

- Turning on selective catalytic reduction systems at plants Bowen, Hammond and Wansley. This is expected to reduce the company's emissions of nitrogen oxides and, therefore, its contribution to metro Atlanta's ozone from 15 percent to 6 percent.

- Filing applications for four more scrubbers – two for Plant Wansley and two additional scrubbers for Plant Bowen. Two scrubbers are already under construction at Plant Bowen. Not only will the scrubbers, which remove sulfur dioxide (SO_2) from power plant emissions, reduce SO_2 emissions on each of these generating units by as much as 95 percent, but they also will reduce emissions of fine particulates and mercury. This is important because the Environmental Protection Agency issued its first mercury rule last year requiring significant reductions in mercury emissions from power plants.

- Working closely with DeKalb County in metro Atlanta, which approved the development of a landfill gas generation plant and a 10-year contract to sell the energy to Georgia Power for our voluntary Green Energy program.

In the past 10 years, we have invested $1 billion in environmental controls, and we'll continue to invest in environmental improvement technologies. In fact, over the next five years, Georgia Power's additional environmental investment is expected to total at least $2.4 billion.

In 2005, we also implemented a new organizational structure that moves key company leaders closer to our customers, employees and the communities we serve. We now have officer positions in major cities around the state, including Athens, Augusta, Columbus, Macon, Rome, Valdosta and, following the merger, Savannah.

Our new structure allows us to enhance efficiencies and operate consistently around the state while providing multiple cross-company leadership development opportunities within Southern Company – a key priority as we work to further develop the diversity and strength of our management ranks.

We believe improving diversity in every facet of our business is, simply put, good for business. That's why last year, for example, we launched a Hispanic Resources Web site, a one-stop shop for information to assist Spanish-speaking customers.

After all our hard work, it's nice to be recognized for our success. *Profiles in Diversity Journal* named Georgia Power to its top-10 list of diversity innovation award winners. We also were one of the Fortune 500 companies recognized as the nation's "Best Workplaces for Commuters," in large part because of SmartRide, our company commuter program that has become more popular than ever because of rising fuel prices. *Site Selection* magazine also recognized us as one of the best company's in North America for economic development.

We're especially proud of our linemen, who really shined at the International Lineman's Rodeo last year in Kansas City, winning first place in the overall, overall apprentice, investor-owned utility and senior divisions, along with a handful of individual event awards.

Continued economic vitality in Georgia helped boost electricity sales and was a key contributor to our strong financial results last year. Businesses and individuals were drawn to the state, increasing the number of customers Georgia Power serves to 2.1 million in 2005, a 1.8 percent increase from the previous year. Our retail sales of electricity climbed 1.4 percent in 2005.

It's clear to me that the work our employees do day in and day out and their commitment to the company are what make us successful – they are our greatest asset.

The changes we made and initiatives we launched last year will help ensure that we continue doing what's best for our employees, customers and communities – that we live up to our motto of being a "Citizen Wherever We Serve" – as we work to meet the state's growing demand for energy.

Sincerely,

Michael D. Garrett
April 17, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Georgia Power Company:

We have audited the accompanying balance sheets and statements of capitalization of Georgia Power Company (the "Company") (a wholly owned subsidiary of Southern Company) as of December 31, 2005 and 2004, 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, 2005. 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 the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements (pages 25 to 57) present fairly, in all material respects, the financial position of Georgia Power Company at December 31, 2005 and 2004, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
February 27, 2006

OVERVIEW

Business Activities

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

Many factors affect the opportunities, challenges, and risks of the Company's primary business of selling electricity. These factors include the ability to maintain a stable regulatory environment, to achieve energy sales growth while containing costs, and to recover rising costs. These costs include those related to growing demand, increasingly stringent environmental standards, and fuel prices. In December 2004, the Company completed a major retail rate proceeding that is expected to provide earnings stability (2004 Retail Rate Plan). This regulatory action also enables the recovery of substantial capital investments to facilitate the continued reliability of the transmission and distribution network and continued environmental improvements at the generating plants. Appropriately balancing environmental expenditures with customer prices will continue to challenge the Company for the foreseeable future. The Company expects further rate proceedings in 2006 to address fuel cost recovery due to higher than expected fuel costs for coal and natural gas.

On December 13, 2005, the Company and Savannah Electric and Power Company (Savannah Electric) entered into a merger agreement, under which Savannah Electric will merge into the Company, with the Company continuing as the surviving corporation (the Merger). The Merger must be approved by Savannah Electric's preferred shareholders and is subject to receipt of certain regulatory approvals from the Federal Energy Regulatory Commission (FERC), the Georgia Public Service Commission (PSC), and the Federal Communications Commission. Pending regulatory approvals, the Merger is expected to be completed by July 2006. See FUTURE EARNINGS POTENTIAL – "Merger" and Note 3 to the financial statements under "Retail Regulatory Matters – Merger" for additional information.

Key Performance Indicators

In striving to maximize shareholder value while providing low-cost energy to more than two million customers, the Company continues to focus on several key indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income. The Company's financial success is directly tied to the satisfaction of its customers. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance, expected weather conditions, and expected capital expenditures. Net income is the primary component of the Company's contribution to Southern Company's earnings per share goal.

The Company's 2005 results compared to its targets for some of these indicators are reflected in the following chart.

Key Performance Indicator	2005 Target Performance	**2005 Actual Performance**
Customer Satisfaction	Top quartile in customer surveys	**Top quartile**
Peak Season EFOR	2.75% or less	**1.42%**
Net Income	$678 million	**$715 million**

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The strong financial performance achieved in 2005 reflects the focus that management places on these indicators, as well as the commitment shown by the employees in achieving or exceeding management's expectations.

Earnings

The Company's 2005 earnings totaled $715 million representing a $57 million (8.7 percent) increase over 2004. Operating income increased in 2005 due to higher base retail revenues resulting from the retail rate increase

effective January 1, 2005 and more favorable weather, as well as higher wholesale revenues resulting from new contracts effective January 1, 2005, partially offset by increased non-fuel operating expenses. The Company's 2004 earnings totaled $658 million representing a $27 million (4.3 percent) increase over 2003. Operating income increased in 2004 due to higher base retail revenues attributable to more favorable weather and customer growth during the year, partially offset by higher non-fuel operating expenses. In addition, lower depreciation and amortization expense resulting from a Georgia PSC three-year retail rate plan approved in 2001 (2001 Retail Rate Plan) significantly offset increased purchased power capacity expenses. The Company's 2003 earnings totaled $631 million, representing a $13 million (2.1 percent) increase over 2002 despite lower base retail revenues resulting from the extremely mild summer weather. Higher wholesale revenues and lower non-fuel operating expenses contributed to the 2003 increase.

RESULTS OF OPERATIONS

A condensed income statement for the Company is as follows:

	Amount	Increase (Decrease) From Prior Year		
	2005	**2005**	2004	2003
		(in millions)		
Operating revenues	**$6,634**	**$1,263**	$457	$ 92
Fuel	**1,831**	**598**	128	101
Purchased power	**1,170**	**194**	200	92
Other operation and maintenance	**1,481**	**81**	153	(78)
Depreciation and amortization	**504**	**229**	(74)	(54)
Taxes other than income taxes	**260**	**32**	15	11
Total operating expenses	**5,246**	**1,134**	422	72
Operating income	**1,388**	**129**	35	20
Total other income and (expense)	**(241)**	**(20)**	5	2
Income taxes	**431**	**52**	13	9
Net income	**716**	**57**	27	13
Dividends on preferred stock	**1**	**-**	-	-
Net income after dividends on preferred stock	**$ 715**	**$ 57**	$ 27	$ 13

Revenues

Operating revenues in 2005, 2004, and 2003 and the percent of change from the prior year are as follows:

	Amount		
	2005	2004	2003
		(in millions)	
Retail – prior year	**$4,777**	$4,310	$4,288
Change in -			
Base rates	**195**	-	-
Sales growth	**135**	151	30
Weather	**21**	32	(66)
Fuel cost recovery and other	**515**	284	58
Retail – current year	**$5,643**	4,777	4,310
Sales for resale -			
Non-affiliates	**519**	247	260
Affiliates	**265**	166	175
Total sales for resale	**784**	413	435
Other operating revenues	**207**	181	169
Total operating revenues	**$6,634**	$5,371	$4,914
Percent change	**23.5%**	9.3%	1.9%

Retail base revenues of $3.6 billion in 2005 increased by $351 million (10.9 percent) from 2004 primarily due to the retail rate increase effective January 1, 2005, sustained economic strength, customer growth, more favorable weather, and generally higher prices to large business customers. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information. Retail base revenues of $3.2 billion in 2004 increased by $183 million (6.0 percent) from 2003 primarily due to an improved economy, customer growth, generally higher prices to the Company's large business customers, and more favorable weather. Retail base revenues of $3 billion in 2003 decreased by $36 million (1.2 percent) from 2002 primarily due to extremely mild summer temperatures and the sluggish economy.

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. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information.

Wholesale revenues from sales to non-affiliated utilities were:

	2005	2004	2003
		(in millions)	
Unit power sales --			
Capacity	$ 33	$ 31	$ 34
Energy	31	33	31
Other power sales --			
Capacity and other	155	75	93
Energy	300	108	102
Total	$519	$247	$260

Revenues from unit power sales contracts remained relatively constant in 2005 and 2004. Revenues from unit power sales contracts decreased slightly in 2003 due to decreased energy sales. Revenues from other non-affiliated sales increased $272 million (148.6 percent) in 2005 and decreased $12 million (6.2 percent) and $8 million (3.9 percent) in 2004 and 2003, respectively. The increase in 2005 is due to new contracts with thirty electric membership corporation customers that went into effect in January 2005 which increased the demand for energy. The capacity component of these transactions increased $73.2 million in 2005 over 2004.

Revenues from sales to affiliated companies within the Southern Company electric system, as well as purchases of energy, will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliated sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the FERC. In 2005, kilowatt-hour (KWH) energy sales to affiliates increased 1.5 percent due to higher demand, while the increase in associated revenues was 59.4 percent due to higher fuel prices. In 2004, KWH energy sales to affiliates decreased 18.2 percent due to lower demand. However, the decline in associated revenues was only 4.9 percent due to higher fuel prices. In 2003, KWH energy sales to affiliates increased 47.5 percent due to the combination of increased demand by Southern Power to meet contractual obligations and the availability of power due to milder-than-normal weather in the Company's service territory. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost.

Other operating revenues increased $25.7 million (14.2 percent) in 2005 from 2004 primarily due to higher transmission revenues of $16 million related to work performed for the other owners of the integrated transmission system in the State of Georgia and higher revenues under the open access tariff agreement, higher outdoor lighting revenues of $5.4 million, and higher customer fees that went into effect in January 2005 of $5.9 million. Other operating revenues increased $11.7 million (6.9 percent) in 2004 over 2003 primarily due to higher revenues from outdoor lighting of $4.2 million and pole attachment rentals of $4.9 million and higher gains on sales of emission allowances of $2 million. Other operating revenues increased $4 million (2.4 percent) in 2003 from the prior year primarily due to an increase in the open access transmission tariff rate, which increased revenues $7 million, and higher revenues from increased customer demand for outdoor lighting services of $4 million, partially offset by lower revenues from the rental of electric property of $4 million.

Energy Sales

KWH sales for 2005 and the percent change by year were as follows:

	KWH	Percent Change		
	2005	2005	2004	2003
	(in billions)			
Residential	23.6	2.9%	5.3%	(1.7)%
Commercial	29.8	6.3	4.0	(0.1)
Industrial	25.0	(5.0)	2.5	(0.1)
Other	0.6	(0.1)	1.1	0.4
Total retail	79.0	1.4	3.8	(0.5)
Sales for resale -				
Non-affiliates	11.2	88.2	(32.5)	9.5
Affiliates	4.9	1.5	(18.2)	47.5
Total sales for resale	16.1	49.6	(26.8)	22.0
Total sales	95.1	7.2	(1.2)	2.6

Residential KWH sales increased 2.9 percent in 2005 over 2004 due to more favorable weather, customer growth of 1.7 percent, and a 1.1 percent increase in the average energy consumption per customer. Commercial KWH sales increased 6.3 percent due to more favorable weather, sustained economic strength, customer growth of 1.8 percent, and a reclassification of customers from industrial to commercial to be consistent with the rate structure approved by the Georgia PSC when compared

to 2004. Industrial sales decreased 5.0 percent primarily due to this reclassification of customers.

Residential KWH sales increased 5.3 percent in 2004 from 2003 due to more favorable weather and a 1.9 percent increase in residential customers. Commercial KWH sales increased 4.0 percent in 2004 due to an improved economy and a 2.8 percent increase in commercial customers. Industrial sales increased 2.5 percent in 2004 due to the improved economy.

Residential KWH sales decreased 1.7 percent in 2003 from 2002 due to the effect of the milder summer weather, despite the 2.0 percent increase in residential customers. Commercial KWH sales in 2003 declined slightly due to the milder summer weather, while industrial KWH sales declined slightly due to the sluggish economy. Average retail sales growth assuming normal weather is expected to be 2.1 percent from 2006 to 2010.

Fuel and Purchased Power 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 generating units. The amount and sources of generation, the average cost of fuel per net KWH generated, and the average cost of purchased power per net KWH were as follows:

	2005	2004	2003
Total generation (billions of KWH)	**80.5**	71.5	73.1
Sources of generation (percent) --			
Coal	**75.3**	75.4	75.4
Nuclear	**18.6**	22.5	21.6
Hydro	**2.4**	2.0	2.7
Oil and gas	**3.7**	0.1	0.3
Average cost of fuel per net KWH generated (cents) --	**2.04**	1.55	1.46
Average cost of purchased power per net KWH (cents) --	**7.25**	5.17	4.03

Fuel expense increased 48.5 percent in 2005 from the prior year primarily due to an increase in the average cost of fuel, particularly natural gas, and a 12.3 percent increase in generation to meet higher demand. Fuel expense increased 11.6 percent in 2004 over 2003 primarily due to an increase in the average cost of coal and natural gas. Fuel expense increased 10.1 percent in 2003 over 2002 due to an increase in generation of 3.9 percent because of higher wholesale energy demands and a 2.8 percent higher average cost of fuel due to the higher prices of coal and natural gas in 2003.

Purchased power expense increased $194 million (19.9 percent) in 2005, $200 million (25.9 percent) in 2004, and $92 million (13.3 percent) in 2003. These increases are primarily the result of new purchased power agreements (PPAs) between the Company and Southern Power that went into effect in each of 2004, 2003, and 2002. Additional capacity expenses associated with these PPAs were $30 million, $65 million, and $75 million in 2005, 2004, and 2003, respectively. The increases in purchased power expenses also reflect the impact of the significant increases in fuel costs discussed previously.

A significant upward trend in the cost of coal and natural gas has emerged since 2003, and volatility in these markets is expected to continue. Increased coal prices have been influenced by a worldwide increase in demand as a result of rapid economic growth in China as well as by increases in mining costs. Higher natural gas prices in the United States are the result of increased demand and slightly lower gas supplies despite increased drilling activity. Natural gas supply interruptions, such as those caused by the 2005 and 2004 hurricanes, result in an immediate market response; however, the long-term impact of this price volatility may be reduced by imports of natural gas and liquefied natural gas. Fuel expenses generally do not affect net income, since they are offset by fuel revenues under the Company's fuel cost recovery provisions.

Other Operating Expenses

In 2005, other operations and maintenance expenses increased $81 million (5.8 percent). Maintenance for generating plant and transmission and distribution increased $23.5 million and $13.9 million, respectively, as a result of scheduled outages and, to a lesser extent, certain flexible projects planned for other periods. Increased employee benefit expense of $18.4 million related to pension and medical benefits and higher property insurance costs of $5.3 million resulting from storm damage also contributed to the increase. Customer

assistance expense and uncollectible account expense also increased an additional $9.3 million in 2005 over 2004, primarily as a result of promotional expenses related to an energy efficiency program and an increased number of customer bankruptcies, respectively. In 2004, other operations and maintenance expenses increased $153 million (12.3 percent) due to the timing of generating plant maintenance of $39 million and transmission and distribution maintenance of $39 million. Increased employee benefit expense of $30 million related to pension and medical benefits and higher workers compensation expense of $8 million also contributed to the increase. In 2003, other operations and maintenance expenses decreased $78 million (5.9 percent) due to the timing of generating plant maintenance of $46 million and transmission and distribution maintenance of $8 million and lower severance costs of $8 million.

Depreciation and amortization increased $229 million (83 percent) in 2005 over 2004 primarily due to the expiration at the end of 2004 of certain provisions of the Company's 2001 Retail Rate Plan. In accordance with the 2001 Retail Rate Plan, the Company amortized an accelerated cost recovery liability as a credit to amortization expense and recognized new Georgia PSC-certified purchased power costs in rates evenly over the three years ended December 31, 2004. This treatment resulted in a credit to amortization expense of $187.1 million in 2004 and a total decrease in depreciation and amortization of $74 million and $54 million in 2004 and 2003, respectively. See Note 3 to the financial statements under "Retail Regulatory Matters -- Rate Plans" for additional information.

Taxes other than income taxes increased $32 million (14.1 percent) primarily due to higher municipal gross receipts taxes of $18.1 million resulting from increased operating revenues and higher property taxes of $14.0 million. Taxes other than income taxes increased $15 million (7.0 percent) in 2004 due to higher municipal gross receipts taxes associated with increased operating revenues. Taxes other than income taxes increased $11 million (5.4 percent) in 2003 due mainly to a favorable true-up of state property tax valuations in 2002.

Other Income and (Expense)

Allowance for equity funds used during construction remained relatively constant in 2005 and increased $15.9 million in 2004, primarily due to the construction of the McIntosh combined cycle Units 10 and 11 which were placed in service in June 2005.

Interest income remained relatively constant in 2005. Interest income decreased $9 million in 2004 and increased $12 million in 2003 when compared to the prior year primarily due to interest on a favorable income tax settlement of $14.5 million in 2003.

Interest expense increased $38.8 million (21.3 percent) in 2005 from 2004 primarily due to the issuance of additional senior notes in 2005 and generally higher interest rates on variable rate debt and commercial paper. Interest expense remained relatively constant in 2004. Interest expense increased in 2003 primarily due to an increase in senior notes outstanding that was partially offset by a reduction in short-term debt outstanding. The Company refinanced or retired $635 million, $400 million, and $665 million of securities in 2005, 2004, and 2003, respectively. Interest capitalized increased in 2005 and 2004 due to the Plant McIntosh construction referenced above and decreased in 2003 due to the transfer of a project to Southern Power in 2002.

Other income and (expense), net increased $17.1 million in 2005 from 2004 primarily due to $14.2 million of additional gas hedge gains. Other income and (expense), net decreased in 2004 primarily due to the $13 million disallowance of Plant McIntosh construction costs in December 2004, partially offset by a $7.5 million decrease in donations and $3.4 million in increased income from a customer pricing program. See Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Hedging Program" and "Plant McIntosh Construction Project" for additional information.

Effects of Inflation

The Company is subject to rate regulation that is based on the recovery of historical costs. In addition, the income tax laws are based on historical costs. Therefore, inflation creates an economic loss because the Company is recovering its costs of investments in dollars that have less purchasing power. While the inflation rate has been relatively low in recent years, it continues to have an adverse effect on the Company because of the large investment in utility plant with long economic lives. Conventional accounting for historical cost does not recognize this economic loss nor the partially offsetting gain that arises through financing facilities with fixed-

money obligations such as long-term debt, preferred stock, and preferred securities. Any recognition of inflation by regulatory authorities is reflected in the rate of return allowed in the Company's approved electric rates.

FUTURE EARNINGS POTENTIAL

General

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

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability of the Company to maintain a stable regulatory environment that continues to allow for the recovery of all prudently incurred costs. Future earnings in the near term will depend, in part, upon growth in energy sales, which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth in the Company's service area.

Environmental Matters

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S District Court for the Northern District of Georgia against the Company and Alabama Power, alleging that the Company and Alabama Power had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws with respect to certain coal-fired generating facilities. Through subsequent amendments and other legal proceedings, the EPA added Savannah Electric as a defendant to the original action and filed a separate action against Alabama Power after it was dismissed from the original action. In these lawsuits, the EPA alleges that NSR violations occurred at eight coal-fired generating facilities, including the Company's Plants Bowen and Scherer. The civil action requests penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. On June 3, 2005, the U.S. District for the Northern District of Alabama issued a decision in favor of Alabama Power on two primary legal issues in the case; however, the decision does not resolve the case, nor does it address other legal issues associated with the EPA's allegations. In accordance with a separate court order, Alabama Power and the EPA are currently participating in mediation with respect to the EPA's claims. The action against the Company and Savannah Electric has been administratively closed since the spring of 2001, and none of the parties has sought to reopen the case. See Note 3 to the financial statements under "Environmental Matters - New Source Review Actions."

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $32,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in this matter could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

In December 2002 and October 2003, the EPA issued final revisions to its NSR regulations under the Clean Air Act. A coalition of states and environmental organizations filed petitions for review of these regulations. On June 24, 2005, the U.S. Court of Appeals for the District of Columbia Circuit upheld, in part, the EPA's December 2002 revisions to its NSR regulations, which included changes to the regulatory exclusions and

methods of calculating emissions increases. However, the court vacated portions of those revisions, including those addressing the exclusion of certain pollution control projects. The October 2003 revisions, which clarified the scope of the existing Routine Maintenance, Repair and Replacement exclusion, have been stayed by the Court of Appeals pending its review of the rules. On October 20, 2005, the EPA also published a proposed rule clarifying the test for determining when an emissions increase subject to the NSR requirements has occurred. The impact of these revisions and proposed rules will depend on adoption of the final rules by the EPA and the State of Georgia's implementation of such rules, as well as the outcome of any additional legal challenges, and, therefore, cannot be determined at this time.

Carbon Dioxide Litigation

In July 2004, attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed a complaint in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. A nearly identical complaint was filed by three environmental groups in the same court. The complaints allege that the companies' emissions of carbon dioxide, a greenhouse gas, contribute to global warming, which the plaintiffs assert is a public nuisance. Under common law public and private nuisance theories, the plaintiffs seek a judicial order (1) holding each defendant jointly and severally liable for creating, contributing to, and/or maintaining global warming and (2) requiring each of the defendants to cap its emissions of carbon dioxide and then reduce those emissions by a specified percentage each year for at least a decade. Plaintiffs have not, however, requested that damages be awarded in connection with their claims. Southern Company believes these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2005, the U.S. District Court for the Southern District of New York granted Southern Company's and the other defendants' motions to dismiss these cases. The plaintiffs filed an appeal to the U.S. Court of Appeals for the Second Circuit on October 19, 2005. The ultimate outcome of these matters cannot be determined at this time.

Plant Wansley Environmental Litigation

In December 2002, the Sierra Club, Physicians for Social Responsibility, Georgia Forestwatch, and one individual filed a civil suit in the U.S. District Court for the Northern District of Georgia against the Company for alleged violations of the Clean Air Act at four of the units at Plant Wansley. 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. The liability phase of the case has concluded with the court ruling in favor of the Company in part and the plaintiffs in part. In March 2005, the U.S. Court of Appeals for the Eleventh Circuit accepted the Company's petition for review of the district court's order, and oral arguments were held on January 24, 2006. The district court case has been administratively closed pending that appeal. If necessary, the district court will hold a separate trial which will address civil penalties and possible injunctive relief requested by the plaintiffs. The ultimate outcome of this matter cannot currently be determined; however, an adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require the payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

Environmental Statutes and Regulations

General

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. Applicable statutes 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 these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2005, the Company had invested approximately $1.2 billion in

capital projects to comply with these requirements, with annual costs of $117.4 million, $47.4 million, and $105.7 million for 2005, 2004, and 2003, respectively. Over the next decade, the Company expects that capital expenditures could exceed an additional $3.3 billion to assure compliance with existing and new regulations, including $410 million, $674.6 million, and $515.8 million for 2006, 2007, and 2008, respectively. Because the Company's compliance strategy is impacted by changes to existing environmental laws and regulations, the cost, availability, and existing inventory of emission allowances, and the Company's fuel mix, the ultimate outcome cannot be determined at this time. Environmental costs that are known and estimable at this time are included in capital expenditures discussed under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein.

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

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Through 2005, the Company had spent approximately $787.9 million in reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions and in monitoring emissions pursuant to the Clean Air Act. Additional controls have been announced and are currently being installed at several plants to further reduce SO_2 and NO_x emissions, maintain compliance with existing regulations, and to meet new requirements.

Approximately $699.8 million of these expenditures are related to reducing NO_x emissions pursuant to state and federal requirements in connection with the EPA's one-hour ozone standard and the 1998 regional NO_x reduction rules. Although the State of Georgia was originally included in the states subject to the regional NO_x rules, the EPA, in August 2005, stayed compliance with these requirements and initiated rulemakings to address issues raised in a petition for reconsideration filed by a coalition of Georgia industries. The impact of the 1998 regional NO_x reduction rules for Georgia will depend on the outcome of the petition for reconsideration and/or any subsequent development and approval of the State of Georgia's state implementation plan.

In 2005, the EPA revoked the one-hour ozone standard and published the final set of rules for implementation of the new, more stringent eight-hour ozone standard. Areas within the Company's service area that have been designated as nonattainment under the eight-hour ozone standard include Macon (Georgia) and a 20-county area within metropolitan Atlanta. State implementation plans, including new emission control regulations necessary to bring those areas into attainment are required for most areas by June 2007. These state implementation plans could require further reductions in NO_x emissions from power plants.

During 2005, the EPA's fine particulate matter "nonattainment" designations became effective for several areas within the Company's service area in Georgia, and the EPA proposed a rule for the implementation of the fine particulate matter standard. The EPA plans to finalize the proposed implementation rule in 2006. State plans for addressing the nonattainment designations are required by April 2008 and could require further reductions in SO_2 and NO_x emissions from power plants. The EPA has also published proposed revisions to lower the level of particulate matter currently allowed.

The EPA issued the final Clean Air Interstate Rule on March 10, 2005. This cap-and-trade rule addresses power plant SO_2 and NO_x emissions that were found to contribute to nonattainment of the eight-hour ozone and fine particulate matter standards in downwind states. Twenty-eight eastern states, including the State of Georgia, are subject to the requirements of the rule. The rule calls for additional reductions of NO_x and/or SO_2 to be achieved in two phases, 2009/2010 and 2015. These reductions will be accomplished by the installation of additional emission controls at the Company's coal-fired facilities or by the purchase of emission allowances from a cap-and-trade program.

The Clean Air Visibility Rule (formerly called the Regional Haze Rule) was finalized on July 6, 2005. The goal of this rule is to restore natural visibility conditions in certain areas (primarily national parks

and wilderness areas) by 2064. The rule involves the application of Best Available Retrofit Technology (BART) requirements and a review each decade, beginning in 2018, of progress toward the goal. BART requires that sources that contribute to visibility impairment implement additional emission reductions, if necessary, to make progress toward remedying current visibility concerns. For power plants, the Clean Air Visibility Rule allows states to determine that the Clean Air Interstate Rule satisfies BART requirements for SO_2 and NO_x. However, additional requirements could be imposed. By December 17, 2007, states must submit implementation plans that contain emission reduction strategies for implementing BART requirements and for achieving sufficient and reasonable progress toward the goal.

On March 15, 2005, the EPA announced the final Clean Air Mercury Rule, a cap-and-trade program for the reduction of mercury emissions from coal-fired power plants. The rule sets caps on mercury emissions to be implemented in two phases, 2010 and 2018, and provides for an emission allowance trading market. The Company anticipates that emission controls installed to achieve compliance with the Clean Air Interstate Rule and the eight-hour ozone and fine-particulate standards will also result in mercury emission reductions. However, the long-term capability of emission control equipment to reduce mercury emissions is still being evaluated, and the installation of additional control technologies may be required.

The impacts of the eight-hour ozone standard, the fine particulate matter nonattainment designations, the Clean Air Interstate Rule, the Clean Air Visibility Rule, and the Clear Air Mercury Rule on the Company, will depend on the development and implementation of rules at the state level. States implementing the Clean Air Mercury Rule and the Clear Air Interstate Rule, in particular, have the option not to participate in the national cap-and-trade programs and could require reductions greater than those mandated by the federal rules. Such impacts will also depend on resolution of pending legal challenges to the Clean Air Interstate Rule, the Clean Air Mercury Rule and a related petition from the State of North Carolina under section 126 of the Clean Air Act, also related to the interstate transport of air pollutants. Therefore, the full impacts of these regulations on the Company cannot be determined at this time. The Company has developed and continually updates a comprehensive environmental compliance strategy to comply with the continuing and new environmental requirements discussed above. As part of this strategy, the Company plans to install additional SO_2, NO_x, and mercury emission controls within the next several years to assure continued compliance with applicable air quality requirements.

Water Quality

In July 2004, the EPA published final rules under the Clean Water Act for the purpose of reducing impingement and entrainment of fish and fish larvae at power plants' cooling water intake structures. The new rules require baseline biological information and, perhaps, installation of fish protection technology near some intake structures at existing power plants.

The Company is installing cooling towers at additional facilities under the Clean Water Act to cool water prior to discharge. Near Atlanta, a cooling tower for one plant was completed in 2004 and two others are scheduled for completion in 2008. The total estimated cost of these projects is $173 million, with $85 million remaining to be spent. The Company is also conducting a study of the aquatic environment at another facility to determine if further thermal controls are necessary at that plant.

The full impact of these new rules will depend on the results of studies and analyses performed as part of the rules' implementation and the actual requirements established by the State of Georgia, and therefore, cannot be determined at this time

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and release 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 and monitor known sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Remediation" for additional information.

Under Georgia PSC ratemaking provisions, $22 million has been deferred in a regulatory liability account related to certain environmental insurance settlements. Under the 2004 Retail Rate Plan, this regulatory liability is being amortized as a credit to expense over a three-year period that began January 1, 2005. However, the Georgia PSC also approved an annual environmental accrual of $5.4 million. Environmental remediation expenditures are being charged against the resulting reserve as they are incurred. The annual accrual amount will be reviewed and adjusted in future regulatory proceedings.

Global Climate Issues

Domestic efforts to limit greenhouse gas emissions have been spurred by international discussions surrounding the Framework Convention on Climate Change, and specifically the Kyoto Protocol -- which proposes constraints on the emissions of greenhouse gases for a group of industrialized countries. The Bush Administration has not supported U.S. ratification of the Kyoto Protocol or other mandatory carbon dioxide reduction legislation; however, in 2002, it did announce a goal to reduce the greenhouse gas intensity of the U.S. – the ratio of greenhouse gas emissions to the value of U.S. economic output -- by 18 percent by 2012. A year later, the Department of Energy (DOE) announced the Climate VISION program to support this goal. Energy-intensive industries, including electricity generation, are the initial focus of this program. Southern Company is involved in the development of a voluntary electric utility sector climate change initiative in partnership with the government. In a memorandum of understanding signed in December 2004 with the DOE under Climate VISION, the utility sector pledged to reduce its greenhouse gas emissions rate by 3 percent to 5 percent by 2010-2012. The Company is continuing to evaluate future energy and emissions profiles relative to the Climate VISION program and is analyzing voluntary programs to support the industry initiative.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates at market-based prices. The Company also has FERC authority to make short-term opportunity sales at market rates. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in that proceeding. In February 2005, Southern Company submitted responsive information. In February 2006, the FERC suspended the proceeding. Any new market-based rate transactions in its retail service territory entered into after February 27, 2005 are subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. The impact of such sales through December 31, 2005 is not expected to exceed $4.9 million. The refund period covers 15 months. In the event that the FERC's default mitigation measures for entities that are found to have market power are ultimately applied, the Company may be required to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates. The final outcome of this matter will depend on the form in which the final methodology for assessing generation market power and mitigation rules may be ultimately adopted and cannot be determined at this time.

In addition, in May 2005, the FERC started an investigation to determine whether Southern Company satisfies the other three parts of the FERC's market-based rate analysis: transmission market power, barriers to entry, and affiliate abuse or reciprocal dealing. The FERC established a new refund period related to this expanded investigation. Any and all new market-based rate transactions both inside and outside Southern Company's retail service territory involving any Southern Company subsidiary, including the Company, will be subject to refund to the extent the FERC orders lower rates as a result of this new investigation, with the 15-month refund period beginning July 19, 2005. The impact of such sales through December 31, 2005 is not expected to exceed $10.9 million, of which $3.2 million relates to sales inside the retail service territory as discussed above. The FERC also directed that this expanded proceeding be held in abeyance pending the outcome of the proceeding on the IIC discussed below.

The Company believes that there is no meritorious basis for this proceeding and is vigorously defending itself in this matter. However, the final outcome of this

matter, including any remedies to be applied in the event of an adverse ruling in this proceeding, cannot now be determined.

Intercompany Interchange Contract

The Company's generation fleet in its retail service territory is operated under the IIC, as approved by the FERC. In May 2005, the FERC also initiated a new proceeding to examine (1) the provisions of the IIC among Alabama Power, the Company, Gulf Power, Mississippi Power, Savannah Electric, Southern Power, and Southern Company Services, Inc., as agent, under the terms of which the power pool of Southern Company is operated, and, in particular, the propriety of the continued inclusion of Southern Power as a party to the IIC, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining Southern Power as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of Southern Power, the FERC authorized Southern Power's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct. The FERC order directs that the administrative law judge who presided over the McIntosh PPA proceeding discussed herein under "PSC Matters – Plant McIntosh Construction Project", be assigned to preside over the hearing in this proceeding and that the testimony and exhibits presented in that proceeding be preserved to the extent appropriate. Hearings are scheduled for September 2006. Effective July 19, 2005, revenues from transactions under the IIC involving any Southern Company subsidiaries, including the Company, are subject to refund to the extent the FERC orders any changes to the IIC.

The Company believes that there is no meritorious basis for this proceeding and is vigorously defending itself in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in this proceeding, cannot now be determined.

Generation Interconnection Agreements

In July 2003, the FERC issued its final rule on the standardization of generation interconnection agreements and procedures (Order 2003). Order 2003 shifts much of the financial burden of new transmission investment from the generator to the transmission provider. The FERC has indicated that Order 2003, which was effective January 20, 2004, is to be applied prospectively to interconnection agreements. Subsidiaries of Tenaska, Inc., as counterparties to three previously executed interconnection agreements with subsidiaries of Southern Company, including the Company, have filed complaints at the FERC requesting that the FERC modify the agreements and that the Company refund a total of $7.9 million previously paid for interconnection facilities, with interest. The Company has opposed all such requests, and the proceedings are still pending. The impact of Order 2003 and its subsequent rehearings on the Company and the final results of these matters cannot be determined at this time.

Transmission

In December 1999, the FERC issued its final rule on Regional Transmission Organizations (RTOs). Since that time, there have been a number of additional proceedings at the FERC designed to encourage further voluntary formation of RTOs or to mandate their formation. However, at the current time, there are no active proceedings that would require the Company to participate in an RTO. Current FERC efforts that may potentially change the regulatory and/or operational structure of transmission include rules related to the standardization of generation interconnection, as well as an inquiry into, among other things, market power by vertically integrated utilities. See "Generation Interconnection Agreements" and "Market-Based Rate Authority" herein for additional information. The final outcome of these proceedings cannot now be determined. However, the Company's financial condition, results of operations, and cash flows could be adversely affected by future changes in the federal regulatory or operational structure of transmission.

PSC Matters

Merger

In connection with the Merger, the Company and Savannah Electric plan to establish a coastal regional organization for the Company that will be operating following completion of the Merger. Management expects that current Savannah Electric employees will fill most of the positions in the new regional organization.

While the Georgia PSC does not have specific approval authority over the merger of electric utilities, in January 2006, the Company and Savannah Electric filed an application with the Georgia PSC for certain approvals necessary to complete the Merger. In particular, the Company and Savannah Electric are seeking the approval of the Georgia PSC with respect to the following matters:

- the transfer of Savannah Electric's generating facilities and certification of the generating facilities as the Company's assets;
- amendments to the Company's Integrated Resource Plan to add the current Savannah Electric's customers and generating facilities;
- the transfer of Savannah Electric's assigned service territory to the Company;
- adoption of the Company's service rules and regulations to the current Savannah Electric customers;
- new fuel rate and base rate schedules that would apply to the Company's sale of electricity to the current Savannah Electric customers;
- adoption of a "merger transition adjustment" rate that would be used to more closely align Savannah Electric's existing base rates to those of the Company and a "merger transition credit" rate that would credit the additional revenues collected from former Savannah Electric customers to the Company's existing customers; and
- the issuance of additional shares of the Company's common stock to Southern Company in exchange for Southern Company's shares of Savannah Electric common stock.

The Company has also requested the Georgia PSC to better align the rates for Savannah Electric's customers with those of the Company. Currently, Savannah Electric customers pay slightly lower base rates and significantly higher fuel rates than the Company's customers. The overall effect is that Savannah Electric customers pay substantially higher overall costs for electricity. See "Fuel Cost Recovery" herein for additional information.

Rate Plans

In December 2004, the Georgia PSC approved the 2004 Retail Rate Plan for the three-year period ending December 31, 2007. Under the terms of the 2004 Retail Rate Plan, earnings are being evaluated annually against a retail return on common equity (ROE) range of 10.25 percent to 12.25 percent. Two-thirds of any earnings above 12.25 percent will be applied to rate refunds, with the remaining one-third retained by the Company. Retail rates were increased by approximately $194 million and customer fees were increased by approximately $9 million effective January 1, 2005 to cover the higher costs of purchased power; operation and maintenance expenses; environmental compliance; and continued investment in new generation, transmission and distribution facilities to support growth and ensure reliability. In 2005 the Company recorded $2.7 million revenue subject to refund for estimated earnings above 12.25 percent retail ROE.

The Company is required to file a general rate case by July 1, 2007, in response to which the Georgia PSC would be expected to determine whether the 2004 Retail Rate Plan should be continued, modified, or discontinued. Until then, the Company will not file for a general base rate increase unless its projected retail ROE falls below 10.25 percent. However, in connection with the Merger, the Company has requested Georgia PSC approval of a "merger transition adjustment" that would be used to adjust Savannah Electric's existing base rates to more closely match the existing base rates for the Company. See Note 3 to the financial statements under "Retail Regulatory Matters - Rate Plans" for additional information.

Plant McIntosh Construction Project

In December 2002 after a competitive bidding process, the Georgia PSC certified PPAs between Southern Power and the Company and Savannah Electric for capacity from Plant McIntosh Units 10 and 11, construction of which was completed in June 2005. In April 2003, Southern Power applied for FERC approval of these PPAs. In July 2003, the FERC accepted the PPAs to become effective June 1, 2005, subject to refund, and ordered that hearings be held. Intervenors opposed the FERC's acceptance of the PPAs, alleging that they did not meet the applicable standards for market-based rates between affiliates. To ensure the timely completion of the Plant McIntosh construction project and the availability of the units in the summer of 2005 for their retail customers, in May 2004, the Company and Savannah Electric requested the Georgia PSC to direct them to acquire the Plant McIntosh construction project. The Georgia PSC issued such an order and the transfer occurred on May 24, 2004 at a total cost of approximately $415 million, including

$14 million of transmission interconnection facilities. Subsequently, Southern Power filed a request to withdraw the PPAs and to terminate the ongoing FERC proceedings. In August 2004, the FERC issued a notice accepting the request to withdraw the PPAs and permitting such request to become effective by operation of law. However, the FERC made no determination on what additional steps may need to be taken with respect to testimony provided in the proceedings. See "FERC Matters - Intercompany Interchange Contract" above for additional information.

In connection with the 2004 Retail Rate Plan, the Georgia PSC approved the transfer of the Plant McIntosh construction project at a total fair market value of approximately $385 million. This value reflected an approximate $16 million disallowance, of which $13 million was attributable to the Company, and reduced the Company's 2004 net income by approximately $8 million. The Georgia PSC also certified a total completion cost of $547 million for the project. In June 2005, Plant McIntosh Units 10 and 11 were placed in service at a total cost that did not exceed the certified amount. Under the 2004 Retail Rate Plan, the Plant McIntosh revenue requirements impact will be reflected in the Company's rates evenly over the three years ending 2007. See Note 3 to the financial statements under "Retail Regulatory Matters -- Rate Plans" and "Plant McIntosh Construction Project" for additional information.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. In recent months, the Company has experienced higher than expected fuel costs for coal and natural gas. Those higher fuel costs have increased the under recovered fuel costs included in the balance sheets herein.

In May 2005, the Georgia PSC approved the Company's request to increase customer fuel rates by approximately 9.5 percent to recover under recovered fuel costs of approximately $508 million existing as of May 31, 2005 over a four-year period that began June 1, 2005. Under recovered fuel amounts for the period subsequent to June 1, 2005 totaled $327.5 million through December 31, 2005. The Georgia PSC's order instructed that such amounts be reviewed semi-annually beginning February 2006. If the amount under or over recovered exceeds $50 million at the evaluation date, the Company would be required to file for a temporary fuel rate change. In addition, Savannah Electric's under recovered fuel costs totaled $77.7 million at December 31, 2005. In accordance with the Georgia PSC order, Savannah Electric was scheduled to file an additional request for a fuel cost recovery increase in January 2006. The Company has agreed with a Georgia PSC staff recommendation to forego the temporary fuel rate process, and Savannah Electric has postponed its scheduled filing. Instead, the Company and Savannah Electric will file a combined request in March 2006 to increase the Company's fuel cost recovery rate.

The case will seek approval of a fuel cost recovery rate based upon future fuel cost projections for the combined Company and Savannah Electric generating fleet as well as the under recovered fuel balances existing at June 30, 2006. The new fuel cost recovery rate would be billed beginning in July 2006 to all of the Company's customers, including the existing Savannah Electric customers. Under recovered amounts as of the date of the Merger will be paid by the appropriate customer groups.

In August 2005, the Georgia PSC initiated an investigation of Savannah Electric's fuel practices. In February 2006, an investigation of the Company's fuel practices was initiated. The Company and Savannah Electric are responding to data requests and cooperating in the investigations. The final outcome of this matter cannot now be determined.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable cost and amounts billed in current regulated rates. Accordingly, any increase in the billing factor would have no significant effect on the Company's revenues or net income, but would increase annual cash flow.

Nuclear

As part of a potential expansion of Plant Vogtle, the Company and Southern Nuclear have notified the Nuclear Regulatory Commission (NRC) of their intent to apply for an early site permit (ESP) this year and a combined construction and operating license (COL) in 2008. In addition, a reactor design from Westinghouse Electric Company has been selected and a purchase agreement is being negotiated. Participation agreements have been reached with each of the existing Plant Vogtle co-owners. See Note 4 to the financial statements for additional information on

these co-owners. At this point, no final decision has been made regarding actual construction. The NRC's streamlined licensing process for new nuclear units allows utilities to seek regulatory approval at various stages. These stages include design certification, which is obtained by the reactor vendor, and the ESP and COL, which are each obtained by the owner-operators of the units. An ESP indicates site approval is obtained before a company decides to build and the COL provides regulatory approval for building and operating the plant. In addition, any generation by the Company must be certified by the Georgia PSC.

Southern Company also is participating in NuStart Energy Development, LLC (NuStart Energy), a broad-based nuclear industry consortium formed to share the cost of developing a COL and the related NRC review. NuStart Energy plans to complete detailed engineering design work and to prepare COL applications for two advanced reactor designs, then to choose one of the applications and file it for NRC review and approval. The COL ultimately is expected to be transferred to one or more of the consortium companies; however, at this time, none of them have committed to build a new nuclear plant.

Other Matters

In accordance with Financial Accounting Standards Board (FASB) Statement No. 87, Employers' Accounting for Pensions, the Company recorded non-cash pension income, before tax, of approximately $21 million, $35 million, and $54 million in 2005, 2004, and 2003, respectively. Postretirement benefit costs for the Company were $47 million, $44 million, and $41 million in 2005, 2004, and 2003, respectively. Both pension and postretirement costs are expected to trend upward. Such amounts are dependent on several factors including trust earnings and changes to the plans. A portion of pension income and postretirement benefit costs is capitalized based on construction-related labor charges. For the Company, pension income or expense and postretirement benefit costs are a component of the regulated rates and generally do not have a long-term effect on net income. For more information regarding pension and postretirement benefits, see Note 2 to the financial statements.

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

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

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

Electric Utility Regulation

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

As reflected in Note 1 to the financial statements under "Regulatory Assets and Liabilities," significant regulatory assets and liabilities have been recorded.

Management reviews the ultimate recoverability of these regulatory assets and liabilities based on applicable regulatory guidelines and accounting principles generally accepted in the United States. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

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

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

Unbilled Revenues

Revenues related to the sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated. Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, power delivery volume, and other operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.

New Accounting Standards

Income Taxes

In December 2004, the FASB issued FASB Staff Position 109-1, Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004 (FSP 109-1), which requires that the generation deduction be accounted for as a special tax deduction rather than as a tax rate reduction. The Company adopted FSP 109-1 in the first quarter of 2005 with no material impact on its financial statements.

Conditional Asset Retirement Obligations

Effective December 31, 2005, the Company adopted the provision of FASB Interpretation No. 47, Conditional Asset Retirement Obligations (FIN 47), which requires that an asset retirement obligation be recorded even though the timing and/or method of settlement are conditional on future events. Prior to December 2005, the Company did not recognize asset retirement obligations for asbestos removal because the timing of retirements was dependent on future events. For additional information, see Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal."

At December 31, 2005, the Company recorded additional asset retirement obligations (and assets) of approximately $91 million. The adoption of FIN 47 did not have any effect on the Company's income statement.

Stock Options

On January 1, 2006, the Company adopted FASB Statement No. 123R, Share-Based Payment, on a modified prospective basis. This statement requires that compensation cost relating to share-based payment transactions be recognized in financial statements. That cost will be measured based on the grant date fair value of the equity or liability instruments issued. Although the compensation expense required under the revised statement differs slightly, the impacts on the Company's financial statements are similar to the pro forma disclosures included in Note 1 to the financial statements under "Stock Options."

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition continued to be stable at December 31, 2005 with emphasis on cost control measures combined with significantly lower costs of capital, achieved through the refinancing and/or redemption of higher-cost securities. Cash flow from operations increased $56 million resulting primarily from increased retail operating revenues (see RESULTS OF OPERATIONS herein), partially offset by the increase in under recovered deferred fuel costs.

Fuel costs are generally recoverable in future periods and are reflected on the balance sheets as under recovered regulatory clause revenues. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information.

In 2005, gross utility plant additions were $906 million. These additions were primarily related to Plant McIntosh Units 10 and 11, transmission and distribution facilities, nuclear fuel, and equipment to comply with environmental standards. The majority of funds needed for gross property additions for the last several years have been provided from operating activities and capital contributions from Southern Company. The statements of cash flows provide additional details.

The Company's ratio of common equity to total capitalization -- including short-term debt -- was 48.3 percent in 2005, 47.7 percent in 2004, and 48.3 percent in 2003. The Company has received investment grade ratings from the major rating agencies.

Sources of Capital

The Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows. However, the type and timing of any future financings, if needed, will depend on market conditions, regulatory approval, and other factors.

The issuance of long-term securities by the Company is subject to the approval of the Georgia PSC. In addition, the issuance of short-term debt securities by the Company is subject to regulatory approval by the FERC following the repeal of the Public Utility Holding Company Act of 1935, as amended, on February 8, 2006. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the appropriate regulatory authorities, as well as the amounts registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company.

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

To meet short-term cash needs and contingencies, the Company had credit arrangements with banks totaling $780 million, of which $778 million was unused, at the beginning of 2006. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper and extendible commercial notes at the request and for the benefit of the Company and the other retail operating companies.

Proceeds from such issuances for the benefit of the Company are loaned directly to the Company and are not commingled with proceeds from issuances for the benefits of any other operating company. The obligations of each company under these arrangements are several; there is no cross affiliate credit support. As of December 31, 2005, the Company had outstanding $268 million of commercial paper and no extendible commercial notes.

At the beginning of 2006, bank credit arrangements were as follows:

		Expires		
Total	Unused	2006	2007	2010
		(in millions)		
$780	$778	$70	$350	$360

The credit arrangements that expire in 2006 allow for the execution of term loans for an additional two-year period.

Financing Activities

During 2005, the Company issued $810 million of long-term debt. The issuances were used to refund $635 million of long-term debt and to fund the Company's ongoing construction program.

Subsequent to December 31, 2005, the Company redeemed all of its outstanding preferred stock at a redemption price of $107 per share.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- or Baa3 or below. Generally, collateral may be provided for by a Southern Company guaranty, letter of credit, or cash. These contracts are primarily for physical electricity purchases and sales. At December 31, 2005, the maximum potential collateral requirements at a BBB- or Baa3 rating were approximately $6 million. The maximum potential collateral requirements at a rating below BBB- or Baa3 were approximately $245 million.

The Company is also party to certain derivative agreements that could require collateral and/or accelerated payment in the event of a credit rating change to below investment grade. These agreements are primarily for natural gas price risk management activities. At December 31, 2005, the Company had no material exposure related to these agreements.

Market Price Risk

Due to cost-based rate regulation, the Company has limited exposure to market rate 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 and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress tests, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company has entered into forward starting interest rate swaps that have been designated as hedges. These swaps have a notional amount of $300 million and are related to anticipated debt issuances over the next two years. The weighted average interest rate on outstanding variable long-term debt that has not been hedged at January 1, 2006 was 3.56 percent. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $3.3 million at January 1, 2006. For further information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

To mitigate residual risks relative to movements in electricity prices, the Company enters into fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, into similar contracts for gas purchases.

The Company has implemented a fuel hedging program at the instruction of the Georgia PSC. Fair

value of changes in energy-related derivative contracts and year-end valuations were as follows at December 31:

	Changes in Fair Value	
	2005	2004
	(in millions)	
Contracts beginning of year	**$5.8**	$ 3.2
Contracts realized or settled	**(40.0)**	(12.2)
Current period changes (a)	**60.8**	14.8
Contracts end of year	**$26.6**	$ 5.8

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

	Source of 2005 Year-End Valuation Prices		
	Total	Maturity	
	Fair Value	Year 1	1-3 Years
		(in millions)	
Actively quoted	**$26.8**	$16.4	$10.4
External sources	**(0.2)**	(0.2)	-
Contracts end of year	**$26.6**	$16.2	$10.4

Unrealized gains and losses from mark to market adjustments on derivative contracts related to the Company's fuel hedging programs are recorded as regulatory assets and liabilities. Realized gains and losses from these programs are included in fuel expense and are recovered through the Company's fuel cost recovery mechanism. Of the net gains, the Company is allowed to retain 25 percent in earnings. In 2005, the Company had a total net gain of $64.1 million, of which the Company retained $16.0 million. See Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Hedging Program" for additional information. Gains and losses on derivative contracts that are not designated as hedges are recognized in the statements of income as incurred. At December 31, 2005, the fair value of derivative energy contracts was reflected in the financial statements as follows:

	Amounts
	(in millions)
Regulatory liabilities, net	$26.7
Net income	(0.1)
Total fair value	$26.6

Unrealized gains (losses) recognized in income in 2005, 2004, and 2003 were not material. The Company is exposed to market price risk in the event of nonperformance by counterparties to the derivative energy contracts. The Company's policy is to enter into agreements with counterparties that have investment grade credit ratings by Moody's and Standard & Poor's or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to be $1.3 billion for 2006, $1.4 billion for 2007, and $1.3 billion for 2008. Environmental expenditures included in these amounts are $410 million, $674.6 million, and $515.8 million for 2006, 2007, and 2008, respectively. Actual construction costs may vary from this estimate because of changes in such factors as: business conditions; environmental regulations; nuclear plant regulations; FERC rules and transmission regulations; load projections; the cost and efficiency of construction labor, equipment, and materials; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

As a result of requirements by the NRC, the Company has established external trust funds for nuclear decommissioning costs. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning." Also as discussed in Note 1 to the financial statements under "Nuclear Fuel Disposal Costs," in 1993 the DOE implemented a special assessment over a 15-year period on utilities with nuclear plants to be used for the decontamination and decommissioning of its nuclear fuel enrichment facilities.

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the Georgia PSC and the FERC.

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

Amounts in the following chart exclude any effects on the Company of the Merger.

Contractual Obligations

	2006	2007-2008	2009-2010	After 2010	Total
			(in millions)		
Long-term debt [a] --					
Principal	$153	$306	$282	$4,563	$5,304
Interest	265	496	468	4,989	6,218
Preferred stock	15	-	-	-	15
Commodity derivative obligations[b]	12	-	-	-	12
Operating leases	34	58	44	58	194
Purchase commitments[c] --					
Capital [d]	1,251	2,738	2,421	-	6,410
Coal	1,579	2,220	694	40	4,533
Nuclear fuel	44	42	25	64	175
Natural gas[e]	577	525	511	2,047	3,660
Purchased power	343	689	559	994	2,585
Long-term service agreements	7	18	24	144	193
Trusts[f] --					
Nuclear decommissioning	7	14	14	117	152
Postretirement benefits	18	41	-	-	59
DOE assessments	4	-	-	-	4
Total	$4,309	$7,147	$5,042	$13,016	$29,514

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2006, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest risk.

(b) For additional information see Notes 1 and 6 to the financial statements herein.

(c) The Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses for the last three years were $1.5 billion, $1.4 billion, and $1.2 billion, respectively.

(d) The Company forecasts capital expenditures over a five-year period. Amounts represent current estimates of total expenditures, excluding those amounts related to contractual purchase commitments for uranium and nuclear fuel conversion, enrichment, and fabrication services. At December 31, 2005, significant purchase commitments were outstanding in connection with the construction program.

(e) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on the New York Mercantile Exchange future prices at December 31, 2005.

(f) Projections of nuclear decommissioning trust contributions are based on the 2004 Retail Rate Plan. The Company forecasts postretirement trust contributions over a three-year period. No contributions related to the Company's pension trust are currently expected during this period. See Note 2 to the financial statements for additional information related to the pension and postretirement plans, including estimated benefit payments. Certain benefit payments will be made through the related trusts. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2005 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales growth, storm cost recovery and repairs, environmental regulations and expenditures, the Company's projections for postretirement benefit trust contributions, financing activities, access to sources of capital, the proposed merger of Savannah Electric and the Company, the impacts of the adoption of new accounting rules, completion of construction projects, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will", "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory change, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, and implementation of the Energy Policy Act of 2005, and also changes in environmental, tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including FERC matters and the pending EPA civil action against the Company;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and population, and business growth (and declines);
- available sources and costs of fuels;
- ability to control costs;
- investment performance of the Company's employee benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate cases related to fuel cost recovery;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due;
- the ability to obtain new short- and long-term contracts with neighboring utilities;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents similar to the August 2003 power outage in the Northeast;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports, including the Form 10-K, filed by the Company from time to time with the Securities and Exchange Commission.

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

STATEMENTS OF INCOME

For the Years Ended December 31, 2005, 2004, and 2003

Georgia Power Company 2005 Annual Report

	2005	2004	2003
		(in thousands)	
Operating Revenues:			
Retail sales	**$5,642,812**	$4,776,985	$4,309,972
Sales for resale --			
Non-affiliates	**519,673**	246,545	259,376
Affiliates	**264,989**	166,245	174,855
Other revenues	**206,729**	181,033	169,304
Total operating revenues	**6,634,203**	5,370,808	4,913,507
Operating Expenses:			
Fuel	**1,830,829**	1,232,496	1,103,963
Purchased power --			
Non-affiliates	**408,563**	304,978	258,621
Affiliates	**761,466**	671,098	516,944
Other operations	**949,722**	902,167	827,972
Maintenance	**531,168**	498,114	419,206
Depreciation and amortization	**504,248**	275,488	349,984
Taxes other than income taxes	**259,825**	227,806	212,827
Total operating expenses	**5,245,821**	4,112,147	3,689,517
Operating Income	**1,388,382**	1,258,661	1,223,990
Other Income and (Expense):			
Allowance for equity funds used during construction	**26,808**	26,659	10,752
Interest income	**6,281**	6,657	15,625
Interest expense, net of amounts capitalized	**(221,199)**	(182,370)	(182,583)
Interest expense to affiliate trusts	**(59,510)**	(44,565)	-
Distributions on mandatorily redeemable preferred securities	**-**	(15,839)	(59,675)
Other income (expense), net	**5,742**	(11,362)	(10,551)
Total other income and (expense)	**(241,878)**	(220,820)	(226,432)
Earnings Before Income Taxes	**1,146,504**	1,037,841	997,558
Income taxes	**430,812**	379,170	366,311
Net Income	**715,692**	658,671	631,247
Dividends on Preferred Stock	**693**	670	670
Net Income After Dividends on Preferred Stock	**$714,999**	$658,001	$630,577

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

STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2005, 2004, and 2003

Georgia Power Company 2005 Annual Report

	2005	2004	2003
		(in thousands)	
Operating Activities:			
Net income	**$ 715,692**	$ 658,671	$ 631,247
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization	**592,264**	361,958	424,321
Deferred income taxes and investment tax credits, net	**231,708**	251,623	199,265
Deferred expenses - affiliates	**1,268**	(10,563)	(7,399)
Allowance for equity funds used during construction	**(26,808)**	(26,659)	(10,752)
Pension, postretirement, and other employee benefits	**(19,468)**	(15,868)	(30,225)
Tax benefit of stock options	**15,711**	9,701	11,649
Other, net	**(11,068)**	(19,764)	18,929
Changes in certain current assets and liabilities --			
Receivables	**(591,498)**	(227,204)	(4,395)
Fossil fuel stock	**2,528**	(46,730)	(17,490)
Materials and supplies	**(53,942)**	618	(7,677)
Prepaid income taxes	**(43,626)**	14,358	(3,951)
Other current assets	**4,108**	(23,672)	1,599
Accounts payable	**110,118**	132,001	(62,553)
Accrued taxes	**85,098**	(64,563)	52,348
Accrued compensation	**3,822**	(6,664)	(3,111)
Other current liabilities	**33,289**	5,836	19,845
Net cash provided from operating activities	**1,049,196**	993,079	1,211,650
Investing Activities:			
Property additions	**(842,870)**	(741,151)	(717,993)
Nuclear decommissioning trust fund purchases	**(381,235)**	(541,048)	(656,806)
Nuclear decommissioning trust fund sales	**372,536**	532,349	648,107
Purchase of property from affiliates	**-**	(339,750)	(2)
Cost of removal net of salvage	**(29,428)**	(21,756)	(28,265)
Change in construction payables, net of joint owner portion	**4,037**	413	(32,223)
Other	**(315)**	(4,961)	1,008
Net cash used for investing activities	**(877,275)**	(1,115,904)	(786,174)
Financing Activities:			
Increase (decrease) in notes payable, net	**59,509**	70,956	(220,400)
Proceeds --			
Senior notes	**625,000**	600,000	1,000,000
Pollution control bonds	**185,000**	-	-
Mandatorily redeemable preferred securities	**-**	200,000	-
Capital contributions from parent company	**149,034**	260,068	40,809
Redemptions --			
Pollution control bonds	**(185,000)**	-	-
Senior notes	**(450,000)**	(200,000)	(665,000)
Mandatorily redeemable preferred securities	**-**	(200,000)	-
Payment of preferred stock dividends	**(546)**	(654)	(696)
Payment of common stock dividends	**(556,100)**	(565,500)	(565,800)
Other	**(21,679)**	(17,247)	(22,563)
Net cash provided from (used for) financing activities	**(194,782)**	147,623	(433,650)
Net Change in Cash and Cash Equivalents	**(22,861)**	24,798	(8,174)
Cash and Cash Equivalents at Beginning of Year	**33,497**	8,699	16,873
Cash and Cash Equivalents at End of Year	**$ 10,636**	$ 33,497	$ 8,699
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $10,871, $8,920, and $5,428 capitalized, respectively)	**$250,445**	$228,190	$215,463
Income taxes (net of refunds)	**207,973**	127,115	145,048

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

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BALANCE SHEETS
At December 31, 2005 and 2004
Georgia Power Company 2005 Annual Report

Assets	2005	2004
		(in thousands)
Current Assets:		
Cash and cash equivalents	**$ 10,636**	$ 33,497
Receivables --		
Customer accounts receivable	**418,154**	317,937
Unbilled revenues	**141,875**	140,027
Under recovered regulatory clause revenues	**454,683**	345,542
Other accounts and notes receivable	**110,397**	94,377
Affiliated companies	**84,597**	17,042
Accumulated provision for uncollectible accounts	**(8,647)**	(7,100)
Fossil fuel stock, at average cost	**181,739**	184,267
Vacation pay	**59,190**	57,372
Materials and supplies, at average cost	**323,908**	270,422
Prepaid expenses	**70,825**	32,695
Other	**50,248**	28,262
Total current assets	**1,897,605**	1,514,340
Property, Plant, and Equipment:		
In service	**19,603,249**	18,681,533
Less accumulated provision for depreciation	**7,575,926**	7,217,607
	12,027,323	11,463,926
Nuclear fuel, at amortized cost	**134,798**	124,745
Construction work in progress	**563,155**	766,140
Total property, plant, and equipment	**12,725,276**	12,354,811
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**68,188**	66,192
Nuclear decommissioning trusts, at fair value	**486,591**	459,194
Other	**71,468**	64,571
Total other property and investments	**626,247**	589,957
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**500,882**	505,664
Prepaid pension costs	**476,458**	450,270
Deferred under recovered regulatory clause revenues	**295,116**	-
Other regulatory assets	**330,483**	246,462
Other	**195,716**	160,834
Total deferred charges and other assets	**1,798,655**	1,363,230
Total Assets	**$17,047,783**	$15,822,338

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

BALANCE SHEETS
At December 31, 2005 and 2004
Georgia Power Company 2005 Annual Report

Liabilities and Stockholder's Equity	2005	2004
		(in thousands)
Current Liabilities:		
Securities due within one year	$ 167,317	$ 452,498
Notes payable	267,743	208,233
Accounts payable --		
Affiliated	285,019	194,253
Other	360,455	310,763
Customer deposits	129,293	115,661
Accrued taxes --		
Income taxes	150,896	78,269
Other	204,778	129,520
Accrued interest	88,885	74,529
Accrued vacation pay	45,602	44,894
Accrued compensation	137,303	127,340
Other	120,312	83,632
Total current liabilities	1,957,603	1,819,592
Long-term Debt (See accompanying statements)	4,179,218	3,709,852
Long-term Debt Payable to Affiliated Trusts (See accompanying statements)	969,073	969,073
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	2,730,303	2,556,040
Deferred credits related to income taxes	158,759	170,973
Accumulated deferred investment tax credits	287,726	300,018
Employee benefit obligations	358,137	331,002
Asset retirement obligations	627,465	504,515
Other cost of removal obligations	404,614	411,692
Other regulatory liabilities	97,015	84,678
Other	63,335	59,733
Total deferred credits and other liabilities	4,727,354	4,418,651
Total Liabilities	11,833,248	10,917,168
Preferred Stock (See accompanying statements)	-	14,609
Common Stockholder's Equity (See accompanying statements)	5,214,535	4,890,561
Total Liabilities and Stockholder's Equity	$17,047,783	$15,822,338
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2005 and 2004
Georgia Power Company 2005 Annual Report

	2005	2004	2005	2004
		(in thousands)	*(percent of total)*	
Long-Term Debt:				
Long-term notes payable --				
5.50% due December 1, 2005	$ -	$ 150,000		
Variable rate (1.66% to 1.96% at 1/1/05) due 2005	-	300,000		
6.20% due February 1, 2006	**150,000**	150,000		
4.875% due July 15, 2007	**300,000**	300,000		
4.10% due August 15, 2009	**125,000**	125,000		
Variable rate (4.53% at 1/1/06) due 2009	**150,000**	150,000		
4.00% to 6.00% due 2011-2045	**1,850,000**	1,225,000		
Total long-term notes payable	**2,575,000**	2,400,000		
Other long-term debt --				
Pollution control revenue bonds -- non-collateralized:				
2.83% to 5.45% due 2012-2034	**812,560**	812,560		
Variable rate (2.82% to 3.08% at 1/1/06) due 2011-2032	**873,330**	873,330		
Total other long-term debt	**1,685,890**	1,685,890		
Capitalized lease obligations	**74,484**	76,982		
Unamortized debt premium (discount), net	**(3,448)**	(522)		
Total long-term debt (annual interest requirement -- $205.5 million)	**4,331,926**	4,162,350		
Less amount due within one year	**152,708**	452,498		
Long-term debt excluding amount due within one year	**4,179,218**	3,709,852	**40.3%**	38.7%
Long-term Debt Payable to Affiliated Trusts:				
4.88% to 7.13% due 2042 (annual interest requirement -- $59.5 million)	**969,073**	**969,073**	**9.4**	10.1
Cumulative Preferred Stock:				
$100 stated value at 4.60%				
Authorized -- 5,000,000 shares				
Outstanding -- 145,689 shares (annual dividend requirement -- $0.7 million)	**14,609**	14,609		
Less amount due within one year	**14,609**	-		
Total cumulative preferred stock excluding amount due within one year	-	14,609	**0.0**	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	**2,643,012**	2,478,268		
Retained earnings	**2,261,698**	2,102,798		
Accumulated other comprehensive income (loss)	**(34,425)**	(34,755)		
Total common stockholder's equity	**5,214,535**	4,890,561	**50.3**	51.0
Total Capitalization	**$10,362,826**	$9,584,095	**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, 2005, 2004, and 2003

Georgia Power Company 2005 Annual Report

	Common Stock	Paid-In Capital	Retained Earnings	Other Comprehensive Income (loss)	Total
			(in thousands)		
Balance at December 31, 2002	$344,250	$2,156,080	$1,945,520	$(11,403)	$4,434,447
Net income after dividends on preferred stock	-	-	630,577	-	630,577
Capital contributions from parent company	-	52,458	-	-	52,458
Other comprehensive income (loss)	-	-	-	(11,471)	(11,471)
Cash dividends on common stock	-	-	(565,800)	-	(565,800)
Balance at December 31, 2003	**344,250**	**2,208,538**	**2,010,297**	**(22,874)**	**4,540,211**
Net income after dividends on preferred stock	-	-	658,001	-	658,001
Capital contributions from parent company	-	269,769	-	-	269,769
Other comprehensive income (loss)	-	-	-	(11,881)	(11,881)
Cash dividends on common stock	-	-	(565,500)	-	(565,500)
Other	-	(39)	-	-	(39)
Balance at December 31, 2004	**344,250**	**2,478,268**	**2,102,798**	**(34,755)**	**4,890,561**
Net income after dividends on preferred stock	-	-	714,999	-	714,999
Capital contributions from parent company	-	164,745	-	-	164,745
Other comprehensive income (loss)	-	-	-	330	330
Cash dividends on common stock	-	-	(556,100)	-	(556,100)
Other	-	(1)	1	-	-
Balance at December 31, 2005	**$344,250**	**$2,643,012**	**$2,261,698**	**$(34,425)**	**$5,214,535**

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

STATEMENTS OF COMPREHENSIVE INCOME

For the Years Ended December 31, 2005, 2004, and 2003

Georgia Power Company 2005 Annual Report

	2005	2004	2003
		(in thousands)	
Net income after dividends on preferred stock	**$714,999**	$658,001	$630,577
Other comprehensive income (loss):			
Change in additional minimum pension liability, net of tax of $(1,981), $(3,861) and $(5,133), respectively	**(3,140)**	(6,122)	(8,138)
Change in fair value of marketable securities, net of tax of $317 and $(114)	**501**	(181)	-
Changes in fair value of qualifying hedges, net of tax of $1,214, $(5,046) and $(3,241), respectively	**1,925**	(7,999)	(5,550)
Less: Reclassification adjustment for amounts included in net income, net of tax of $848, $1,528 and $1,208, respectively	**1,044**	2,421	2,217
Total other comprehensive income (loss)	**330**	(11,881)	(11,471)
Comprehensive Income	**$715,329**	$646,120	$619,106

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Georgia Power Company (Company) is a wholly owned subsidiary of Southern Company, which is the parent company of five retail operating companies, Southern Power Company (Southern Power), Southern Company Services (SCS), Southern Communications Services (SouthernLINC Wireless), Southern Company Holdings (Southern Holdings), Southern Nuclear Operating Company (Southern Nuclear), Southern Telecom, and other direct and indirect subsidiaries. The retail operating companies -- Alabama Power, the Company, Gulf Power, Mississippi Power, and Savannah Electric -- provide electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast. Southern Power constructs, owns, and manages Southern Company's competitive generation assets and sells electricity at market-based rates in the wholesale market. Contracts among the retail operating companies and Southern Power -- related to jointly owned generating facilities, interconnecting transmission lines, or the exchange of electric power -- are regulated by the Federal Energy Regulatory Commission (FERC). SCS -- the system service company -- provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications services to the retail operating companies and also markets these services to the public within the Southeast. Southern Telecom provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding subsidiary for Southern Company's investments in synthetic fuels and leveraged leases and various other energy-related businesses. Southern Nuclear operates and provides services to Southern Company's nuclear power plants. In January 2006, Southern Company completed the sale of substantially all the assets of Southern Company Gas, its competitive retail natural gas marketing subsidiary.

The equity method is used for subsidiaries in which the Company has significant influence but does not control and for variable interest entities where the Company is not the primary beneficiary. Certain prior years' data presented in the financial statements have been reclassified to conform to current year presentation.

Southern Company was registered as a holding company under the Public Utility Holding Company Act of 1935, as amended (PUHCA), until its repeal on February 8, 2006, and Southern Company and its subsidiaries, including the Company, were subject to the regulatory provisions of the PUHCA. The Company is subject to regulation by the FERC and the Georgia Public Service Commission (PSC). The Company follows accounting principles generally accepted in the United States and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires the use of estimates and the actual results may differ from those estimates.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, purchasing, accounting and statistical analysis, finance and treasury, tax, information resources, marketing, auditing, insurance and pension administration, human resources, systems and procedures, and other services with respect to business and operations and power pool operations. Costs for these services amounted to $330 million in 2005, $292 million in 2004, and $303 million in 2003. Cost allocation methodologies used by SCS were approved by the Securities and Exchange Commission prior to the repeal of the PUHCA 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 $328 million in 2005, $311 million in 2004, and $289 million in 2003.

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. Billings under these agreements with Southern Power amounted to $5.2 million in 2005, $4.8 million in 2004, and $5.3 million in 2003.

The Company has an agreement with SouthernLINC Wireless under which the Company receives digital wireless communications services and purchases digital equipment. Costs for these services amounted to $7.3 million in 2005, $7.7 million in 2004, and $7.4 million in 2003.

Southern Company holds a 30 percent ownership in Alabama Fuel Products, LLC (AFP), which produces synthetic fuel. The Company has an agreement with an indirect subsidiary of Southern Company that provides services for AFP. Under this agreement, the Company provides certain accounting functions, including processing and paying fuel transportation invoices, and the Company is reimbursed for its expenses. Amounts billed under this agreement totaled approximately $61 million in 2005, $53 million in 2004, and $38 million in 2003. In addition, the Company purchases synthetic fuel from AFP for use at plants Branch, McDonough, and Bowen. Fuel purchases totaled $216 million in 2005, $163 million in 2004, and $91 million in 2003.

The Company has entered into several purchased power agreements (PPAs) with Southern Power for capacity and energy. Expenses associated with these PPAs were $419 million, $282 million, and $203 million in 2005, 2004, and 2003, respectively. Additionally, the Company recorded a reduction of $1 million and an increase of $11 million of prepaid capacity expenses included on the balance sheets at December 31, 2005 and 2004, respectively. See Note 7 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, the Company operates Plant Scherer, and Gulf Power reimburses the Company for its proportionate share of the related expenses which were $4.3 million in 2005, $6.8 million in 2004, and $4.9 million in 2003. The Company has an agreement with Savannah Electric under which the Company jointly owns a portion of Plant McIntosh. Under this agreement, Savannah Electric operates Plant McIntosh, and the Company reimburses Savannah Electric for its proportionate share of the related expenses which were $5.5 million in 2005, $3.3 million in 2004, and $3.7 million in 2003. See Note 4 for additional information.

The Company provides incidental services to other Southern Company subsidiaries which are generally minor in duration and amount. However, with the hurricane damage experienced by Alabama Power, Gulf Power, and Mississippi Power in the last two years, assistance provided to aid in storm restoration, including company labor, contract labor, and materials, has caused an increase in these activities. The total amount of storm assistance provided to Alabama Power, Gulf Power, and Mississippi Power in 2005 was $4.1 million, $4.4 million, and $55 million, respectively. The total amount of storm assistance provided to Alabama Power and Gulf Power in 2004 was $4.1 million and $6.4 million, respectively. These activities were billed at cost.

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

The retail operating companies, including the Company, and Southern Power 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 7 under "Fuel Commitments" for additional information.

The Company has entered into an agreement to merge with Savannah Electric. See Note 3 under "Retail Regulatory Matters – Merger" 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.

Regulatory assets and (liabilities) reflected in the Company's balance sheets at December 31 relate to the following:

	2005	2004	Note
	(in millions)		
Deferred income tax charges	$ 501	$506	(a)
Premium on reacquired debt	170	177	(b)
Corporate building lease	52	53	(e)
Vacation pay	59	57	(d)
Postretirement benefits	18	20	(e)
DOE assessments	6	10	(c)
Generating plant outage costs	46	40	(g)
Other regulatory assets	33	11	(e)
Asset retirement obligation	65	(20)	(a)
Other cost of removal obligations	(404)	(412)	(a)
Deferred income tax credits	(159)	(171)	(a)
Environmental remediation	(19)	(22)	(f)
Purchased power	(33)	-	(f)
Other regulatory liabilities	(30)	(6)	(e)
Total	$ 305	$243	

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

(a) Asset retirement and removal liabilities are recorded, deferred income tax assets are recovered, and deferred tax liabilities are amortized over the related property lives, which may range up to 60 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities.

(b) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue which may range up to 50 years.

(c) Assessments for the decontamination and decommissioning of the DOE's nuclear fuel enrichment facilities are recorded annually from 1993 through 2006.

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

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

(f) Amortized over a three-year period ending in 2007. See Note 3 under "Retail Regulatory Matters - Rate Plans."

(g) See "Property, Plant, and Equipment" herein.

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, including plant, exists and, if impaired, write down the assets to their fair value. All regulatory assets and liabilities are reflected in rates.

Revenues

Energy and other revenues are recognized as services are provided. Unbilled revenues are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between the actual recoverable costs and amounts billed in current regulated rates.

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

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense includes the cost of purchased emission allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel. Total charges for nuclear fuel included in fuel expense amounted to $70 million in 2005, $73 million in 2004, and $74 million in 2003.

Nuclear Fuel Disposal Costs

The Company has contracts with the U.S. Department of Energy (DOE) that provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent nuclear fuel in 1998 as required by the contracts, and the Company is pursuing legal remedies against the government for breach of contract. Sufficient pool storage capacity for spent fuel is available at Plant Vogtle to maintain full-core discharge capability for both units into 2015. Construction of an on-site dry storage facility at Plant Vogtle is expected to begin in sufficient time to maintain pool full-core discharge capability. At Plant Hatch, an on-site dry storage facility is operational and can be expanded to accommodate spent fuel through the life of the plant.

Also, the Energy Policy Act of 1992 required the establishment of a Uranium Enrichment Decontamination and Decommissioning Fund, which is funded in part by a special assessment on utilities with nuclear plants. This assessment has been paid over a 15-

year period; the final installment is scheduled to occur in 2006. 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 interest, estimates its remaining liability at December 31, 2005 under this law to be approximately $4 million.

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.

Manufacturer's Tax Credits

The State of Georgia provides a tax credit for qualified investment property to manufacturing companies that construct new facilities. The credit ranges from 1 percent to 8 percent of qualified construction expenditures depending upon the county in which the new facility is located. The Company's policy is to recognize these credits when management believes that they are more likely than not to be allowed by the Georgia Department of Revenue. Manufacturer's tax credits of $12.5 million, $12.9 million, and $12.0 million were recorded in 2005, 2004, and 2003, respectively.

Property, Plant, and Equipment

The Company's property, plant, and equipment consisted of the following at December 31 (in millions):

	2005	2004
Generation	**$ 9,571**	$ 9,002
Transmission	**2,994**	2,870
Distribution	**5,953**	5,744
General	**1,057**	1,038
Plant acquisition adjustment	**28**	28
Total plant in service	**$ 19,603**	$18,682

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

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense as incurred or performed with the exception of certain generating plant maintenance costs. As mandated by the Georgia PSC, the Company defers and amortizes nuclear refueling costs over the unit's operating cycle before the next refueling. The refueling cycles are 18 and 24 months for plants Vogtle and Hatch, respectively. In accordance with the Georgia PSC 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.

Depreciation and Amortization

Depreciation of the original cost of plant in service is provided primarily by using composite straight-line rates, which approximated 2.6 percent in 2005, 2.6 percent in 2004, and 2.7 percent in 2003. Depreciation studies are conducted periodically to update the composite rates that are approved by the Georgia PSC. In connection with the new retail rate plan for the Company ending December 31, 2007 (2004 Retail Rate Plan), effective January 1, 2005, the depreciation rates were revised by the Georgia PSC. The revised depreciation rates had no material impact on the Company's financial statements.

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.

Under the three-year retail rate plan for the Company ending December 31, 2004 (2001 Retail Rate Plan), the Company discontinued recording accelerated depreciation and amortization. Also, the Company was ordered to amortize $333 million, the cumulative balance previously expensed, equally over three years as a credit to amortization expense beginning January

2002. Additionally, the Company was ordered to recognize new Georgia PSC certified purchased power costs in rates evenly over the three years covered by the 2001 Retail Rate Plan. As a result of the purchased power regulatory adjustment, the Company recorded amortization expenses of $14 million in 2003. The Company recorded a credit to amortization expense of $77 million in 2004. See Note 3 under "Retail Regulatory Matters - Rate Plans" for additional information.

Asset Retirement Obligations and Other Costs of Removal

Effective January 1, 2003, the Company adopted FASB Statement No. 143, Accounting for Asset Retirement Obligations. Statement No. 143 established new accounting and reporting standards for legal obligations associated with the ultimate costs of retiring long-lived assets. The present value of the ultimate costs for an asset's future retirement is recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In addition, effective December 31, 2005, the Company adopted the provisions of FASB Interpretation No. 47, Conditional Asset Retirement Obligations (FIN 47), which requires that an asset retirement obligation be recorded even though the timing and/or method of settlement are conditional on future events. Prior to December 2005, the Company did not recognize asset retirement obligations for asbestos removal because the timing of their retirements was dependent on future events. The Company has received approval from the Georgia PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations will continue to be reflected on the balance sheets as a regulatory liability. Therefore, the Company had no cumulative effect to net income resulting from the adoption of Statement No. 143 or FIN 47.

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. The fair value of assets legally restricted for settling retirement obligations related to nuclear facilities as of December 31, 2005 was $487 million. In addition, the Company has recognized retirement obligations related to various landfill sites, ash ponds, and underground storage tanks. The Company also recorded additional asset retirement obligations (and assets) of approximately $91 million related to asbestos removal. The Company has also identified retirement obligations related to certain transmission and distribution facilities, leasehold improvements, equipment on customer property, and property associated with the Company's rail lines. However, liabilities for the removal of these assets have not been 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 allowed removal costs in accordance with its regulatory treatment. Any difference between costs recognized under Statement No. 143 and FIN 47 and those reflected in rates are recognized as either a regulatory asset or liability in the balance sheets as ordered by the Georgia PSC. See "Nuclear Decommissioning" herein for further information on amounts included in rates.

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

	2005	2004
	(in millions)	
Balance beginning of year	**$505**	$476
Liabilities incurred	**91**	-
Liabilities settled	**(2)**	(2)
Accretion	**33**	31
Balance end of year	**$627**	$505

If FIN 47 had been adopted as of December 31, 2004, the pro forma asset retirement obligations would have been $591 million.

Nuclear Decommissioning

The Nuclear Regulatory Commission (NRC) requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has external trust funds to comply with the NRC's regulations. Use of the funds is restricted to nuclear decommissioning activities and the funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and state PSCs, as well as the Internal Revenue Service (IRS). The trust funds are invested in a tax-

efficient manner in a diversified mix of equity and fixed income securities and are classified as available-for-sale. The trust funds are included in the balance sheets at fair value, as obtained from quoted market prices for the same or similar investments. Details of the securities held in these trusts at December 31 are as follows:

2005	Unrealized Gains	Unrealized Losses	Fair Value
		(in millions)	
Equity	$76.7	$(6.3)	$325.5
Debt	2.8	(0.8)	135.3
Other	-	-	25.8
Total	**$79.5**	**$(7.1)**	**$486.6**

2004	Unrealized Gains	Unrealized Losses	Fair Value
		(in millions)	
Equity	$68.7	$(4.0)	$308.2
Debt	5.3	(0.1)	138.0
Other	-	-	13.0
Total	$74.0	$(4.1)	$459.2

The contractual maturities of debt securities at December 31, 2005 are as follows: $3.2 million in 2006; $34.9 million in 2007-2010; $32.4 million in 2011-2015; and $57.2 million thereafter.

Sales of the securities held in the trust funds resulted in proceeds of $372.5 million, $532.3 million, and $648.1 million in 2005, 2004, and 2003, respectively, all of which were re-invested. Net realized gains (losses) were $12.6 million, $14.1 million, and $21.3 million in 2005, 2004, and 2003, respectively. Realized gains and losses are determined on a specific identification basis. In accordance with regulatory guidance, all realized and unrealized gains and losses are included in the regulatory liability for Asset Retirement Obligations in the balance sheets and are not included in net income or other comprehensive income. Unrealized gains and losses are considered non-cash transactions for purposes of the statements of cash flow. Unrealized losses were not material in any period presented and do not represent any impairment of the underlying investments.

Amounts previously recorded in internal reserves are being transferred into the external trust funds over periods approved by the Georgia PSC. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed plans with the NRC to ensure that, over time -- the deposits and earnings of the external trust funds will provide the minimum funding amounts prescribed by the NRC. Annual provisions for nuclear decommissioning are based on an annuity method as approved by the Georgia PSC. The amount expensed in 2005 and fund balances were as follows:

	Plant Hatch	Plant Vogtle
	(in millions)	
Amount expensed in 2005	$ -	$ 7
Accumulated provisions:		
External trust funds, at fair value	$313	$174
Internal reserves	-	1
Total	$313	$175

Site study cost is the estimate to decommission a specific facility as of the site study year. The estimated costs of decommissioning based on the most current study performed in 2003 for the Company's ownership interests in plants Hatch and Vogtle were as follows:

	Plant Hatch	Plant Vogtle
Decommissioning periods:		
Beginning year	2034	2027
Completion year	2065	2048
	(in millions)	
Site study costs:		
Radiated structures	$497	$452
Non-radiated structures	49	58
Total	$546	$510

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

Under the 2001 Retail Rate Plan, the Georgia PSC approved the annual decommissioning costs for ratemaking of $9 million. This amount was based on the NRC generic estimate to decommission the radioactive

portion of the facilities as of 2000. The estimates were $383 million and $282 million for plants Hatch and Vogtle, respectively. Significant assumptions used to determine the costs for ratemaking included an estimated inflation rate of 4.7 percent and an estimated trust earnings rate of 6.5 percent.

Under the 2004 Retail Rate Plan, effective January 1, 2005, the Georgia PSC decreased the annual decommissioning costs for ratemaking to $7 million. This amount is based on the NRC generic estimate to decommission the radioactive portion of the facilities as of 2003. The estimates are $421 million and $326 million for plants Hatch and Vogtle, respectively. Significant assumptions used to determine the costs for ratemaking include an estimated inflation rate of 3.1 percent and an estimated trust earnings rate of 5.1 percent. Another significant assumption used was the change in the operating license for Plant Hatch. In January 2002, the NRC granted the Company a 20-year extension of the licenses for both units at Plant Hatch which permits the operation of units 1 and 2 until 2034 and 2038, respectively. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for the anticipated cost of decommissioning.

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

In accordance with regulatory treatment, the Company records AFUDC. AFUDC represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, it increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation expense. Interest related to the construction of new facilities not included in the Company's retail rates is capitalized in accordance with standard interest capitalization requirements. For the years 2005, 2004, and 2003, the average AFUDC rates were 8.02 percent, 8.22 percent, and 5.51 percent, respectively. AFUDC and interest capitalized, net of taxes, were 4.7 percent and 4.9 percent of net income after dividends on preferred stock for 2005 and 2004, respectively, and less than 3 percent for 2003.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment provision is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change. See Note 3 under "Retail Regulatory Matters" and "Plant McIntosh Construction Project" for information regarding a regulatory disallowance by the Georgia PSC in December 2004.

Storm Damage Reserve

The Company maintains a reserve for property damage to cover the cost of damages from major storms to its transmission and distribution lines and the cost of uninsured damages to its generation facilities and other property as mandated by the Georgia PSC. The Company accrues $6.3 million annually that is recoverable through base rates. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for storm damage costs.

Environmental Cost Recovery

Under Georgia PSC ratemaking provisions, $22 million has been deferred in a regulatory liability account related to certain environmental insurance settlements. Under the 2004 Retail Rate Plan, this regulatory liability is being amortized over a three-year period beginning January 1, 2005. However, the Georgia PSC also approved an annual environmental accrual of $5.4 million. Environmental remediation expenditures are charged against the reserve as they are incurred. The annual accrual amount will be reviewed and adjusted in future regulatory proceedings.

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 average costs 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.

Fuel Inventory

Fuel inventory includes the average costs of oil, coal, natural gas, and emission allowances. Fuel is charged to inventory when purchased and then expensed as used. Emission allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Stock Options

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

For pro forma purposes, the Company generally recognizes stock option expense on a straight-line basis over the vesting period. Stock options granted to employees who are eligible for retirement are expensed at the grant date.

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

Net Income	As Reported	Options Impact	Pro Forma
		(in millions)	
2005	**$715**	**$(3)**	**$712**
2004	$658	(3)	$655
2003	$631	(4)	$627

The estimated fair value of stock options granted in 2005, 2004, and 2003 was derived using the Black-Scholes stock option pricing model. The following table shows the assumptions and the weighted average fair values of stock options.

	2005	2004	2003
Interest rate	**3.90%**	3.10%	2.70%
Average expected life of stock options (in years)	**5.0**	5.0	4.3
Expected volatility of common stock	**17.90%**	19.60%	23.60%
Expected annual dividends on common stock	**$1.43**	$1.40	$1.37
Weighted average fair value of stock options granted	**$3.90**	$3.29	$3.59

See Note 8 for additional information.

Financial Instruments

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

through current period income and are recorded on a net basis in the statements of income.

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

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

	Carrying Amount	Fair Value
Long-term debt:	(in millions)	
2005	**$5,227**	**$5,195**
2004	$5,055	$5,125

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

Comprehensive Income

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

Variable Interest Entities

The primary beneficiary of a variable interest entity must consolidate the related assets and liabilities. The Company has established certain wholly-owned trusts to issue preferred securities. However, the Company is not the primary beneficiary of the trusts. Therefore, the investments in these trusts are reflected as Other Investments, and the related loans from the trusts are reflected as Long-Term Debt Payable to Affiliated Trusts on the balance sheets. See Note 6 under "Mandatorily Redeemable Preferred Securities/Long-Term Debt Payable to Affiliated Trusts" for additional information.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. The plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). In 2005, the plan was amended to provide an additional monthly supplement to certain retirees. No contributions to the plan are expected for the year ending December 31, 2006. The Company also provides certain non-qualified benefit plans for a selected group of management and highly compensated employees. Benefits under these non-qualified plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees. The Company funds related trusts to the extent required by the Georgia PSC and the FERC. For the year ended December 31, 2006, such contributions are expected to total approximately $18.4 million. The measurement date for plan assets and obligations is September 30 for each year presented.

Pension Plans

The accumulated benefit obligation for the pension plans was $1.9 billion in 2005 and $1.7 billion in 2004. Changes during the year in the projected benefit obligations, accumulated benefit obligations, and the fair value of plan assets was as follows:

Projected Benefit Obligation	**2005**	2004
	(in millions)	
Balance at beginning of year	**$1,885**	$1,727
Service cost	**45**	42
Interest cost	**106**	101
Benefits paid	**(85)**	(85)
Plan amendments	**13**	1
Actuarial loss	**91**	99
Balance at end of year	**$2,055**	$1,885

	Plan Assets	
	2005	2004
	(in millions)	
Balance at beginning of year	**$2,181**	$2,055
Actual return on plan assets	**339**	207
Benefits paid	**(80)**	(81)
Balance at end of year	**$2,440**	$2,181

In 2005, the projected benefit obligations for the qualified and non-qualified pension plans were $1.945 billion and $110 million, respectively. All plan assets are related to the qualified plan.

Pension plan assets are managed and invested in accordance with all applicable requirements including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity, as described in the table below. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes.

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

	Plan Assets		
	Target	**2005**	2004
Domestic equity	36%	**40%**	36%
International equity	24	**24**	20
Fixed income	15	**17**	26
Real estate	15	**13**	10
Private equity	10	**6**	8
Total	100%	**100%**	100%

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

	2005	2004
	(in millions)	
Funded status	**$385**	$295
Unrecognized transition amount	**(4)**	(8)
Unrecognized prior service cost	**109**	108
Unrecognized net actuarial gain (loss)	**(54)**	21
Prepaid pension asset, net	**$436**	$416

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

	2005	2004
	(in millions)	
Prepaid pension asset	**$476**	$450
Employee benefit obligations	**(96)**	(89)
Other property and investments	**15**	19
Accumulated other comprehensive income	**41**	36
Prepaid pension asset, net	**$436**	$416

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

	2005	2004	2003
	(in millions)		
Service cost	**$ 45**	$ 42	$ 38
Interest cost	**106**	101	100
Expected return on plan assets	**(182)**	(180)	(179)
Recognized net (gain)/loss	**3**	(5)	(19)
Net amortization	**7**	7	6
Net pension (income)	**$(21)**	$(35)	$ (54)

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2005, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2006	$ 88
2007	91
2008	94
2009	97
2010	102
2011 to 2015	$607

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	
	2005	2004
	(in millions)	
Balance at beginning of year	**$726**	$723
Service cost	**10**	10
Interest cost	**41**	41
Benefits paid	**(32)**	(31)
Actuarial loss	**24**	42
Plan amendments	**-**	(59)
Balance at end of year	**$769**	$726

	Plan Assets	
	2005	2004
	(in millions)	
Balance at beginning of year	**$299**	$265
Actual return on plan assets	**38**	32
Employer contributions	**40**	33
Benefits paid	**(32)**	(31)
Balance at end of year	**$345**	$299

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

		Plan Assets	
	Target	**2005**	2004
Domestic equity	43%	**43%**	42%
International equity	21	**22**	23
Domestic fixed income	19	**19**	19
Global fixed income	11	**11**	11
Real estate	4	**3**	3
Private equity	2	**2**	2
Total	100%	**100%**	100%

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

	2005	2004
	(in millions)	
Funded status	**$(424)**	$(428)
Unrecognized transition obligation	**70**	78
Unrecognized prior service cost	**25**	27
Unrecognized net loss	**203**	203
Fourth quarter contributions	**21**	15
Employee benefit obligations recognized in the balance sheets	**$(105)**	$(105)

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

	2005	2004	2003
	(in millions)		
Service cost	**$10**	$ 10	$ 9
Interest cost	**41**	41	40
Expected return on plan assets	**(22)**	(25)	(24)
Net amortization	**18**	18	16
Net postretirement cost	**$47**	$ 44	$ 41

In the third quarter 2004, the Company prospectively adopted FASB Staff Position (FSP) 106-2, Accounting and Disclosure Requirements related to the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (Medicare Act). The Medicare Act provides a 28 percent prescription drug subsidy for Medicare eligible retirees. FSP 106-2 requires recognition of the impacts of the Medicare Act in the accumulated postretirement benefit obligation (APBO) and future cost of service for postretirement medical plans. The effect of the subsidy reduced the Company's expenses for the six months ended December 31, 2004 and for the year ended December 31, 2005 by approximately $5 million and $10 million, respectively, and is expected to have a similar impact on future expenses.

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the accumulated benefit obligation for the postretirement plans. Estimated benefit payments are reduced by drug

subsidy receipts expected as a result of the Medicare Act as follows:

	Benefit Payments	Subsidy Receipts	Total
	(in millions)		
2006	$ 37	$ (3)	$ 34
2007	39	(4)	35
2008	42	(4)	38
2009	46	(4)	42
2010	50	(5)	45
2011 to 2015	280	(34)	246

Actuarial Assumptions

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

	2005	2004	2003
Discount	**5.50%**	5.75%	6.00%
Annual salary increase	**3.00**	3.50	3.75
Long-term return on plan assets	**8.50**	8.50	8.50

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

An additional assumption used in measuring the APBO was a weighted average medical care cost trend rate of 10.25 percent for 2005, decreasing gradually to 4.75 percent through the year 2014, 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, 2005, as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$70	$62
Service and interest costs	5	4

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides a 75 percent matching contribution up to 6 percent of an employee's base salary. Total matching contributions made to the plan for the years 2005, 2004, and 2003 were $19 million, $18 million, and $18 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, and citizen enforcement of environmental requirements such as opacity and other air quality standards, 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 pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S District Court for the Northern District of Georgia against the Company and Alabama Power, alleging that the Company and Alabama Power had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws with respect to certain coal-fired generating facilities. Through subsequent amendments and other legal proceedings, the EPA added Savannah Electric as a defendant to the original action and filed a separate action against Alabama Power after it was dismissed from the original action. In these lawsuits, the

EPA alleges that NSR violations occurred at eight coal-fired generating facilities, including the Company's Plants Bowen and Scherer. The civil action requests penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. On June 3, 2005, the U.S. District for the Northern District of Alabama issued a decision in favor of Alabama Power on two primary legal issues in the case; however, the decision does not resolve the case, nor does it address other legal issues associated with the EPA's allegations. In accordance with a separate court order, Alabama Power and the EPA are currently participating in mediation with respect to the EPA's claims. The action against the Company and Savannah Electric has been administratively closed since the spring of 2001, and none of the parties has sought to reopen the case.

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $32,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in this case could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

Plant Wansley Environmental Litigation

In December 2002, the Sierra Club, Physicians for Social Responsibility, Georgia Forestwatch, and one individual filed a civil suit in the U.S. District Court for the Northern District of Georgia against the Company for alleged violations of the Clean Air Act at four of the units at Plant Wansley. 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. The liability phase of the case has concluded with the court ruling in favor of the Company in part and the plaintiffs in part. In March 2005, the U.S. Court of Appeals for the Eleventh Circuit accepted the Company's petition for review of the district court's order, and oral arguments were held on January 24, 2006. The district court case has been administratively closed pending that appeal. If necessary, the district court will hold a separate trial which will address civil penalties and possible injunctive relief requested by the plaintiffs. The ultimate outcome of this matter cannot currently be determined; however, an adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

Environmental Remediation

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. In 1995, the EPA designated the Company and four other unrelated entities as potentially responsible parties at a site in Brunswick, Georgia that is listed on the federal National Priorities List. As of December 31, 2005, the Company had recorded approximately $6 million in cumulative expenses associated with the Company's agreed-upon share of the removal and remedial investigation and feasibility study costs for the Brunswick site. Additional claims for recovery of natural resource damages at the site are anticipated. The Company has also recognized $36 million in cumulative expenses through December 31, 2005 for the assessment and anticipated cleanup of sites on the Georgia Hazardous Sites Inventory.

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 the Company'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.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates at market-based prices. The Company also has FERC authority to make short-term opportunity sales at market rates. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in that proceeding. In February 2005, Southern Company submitted responsive information. In February 2006, the FERC agreed to allow the parties to conduct settlement discussions. Any new market-based rate transactions in its retail service territory entered into after February 27, 2005 are subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. The impact of such sales through December 31, 2005 is not expected to exceed $4.9 million. The refund period covers 15 months. In the event that the FERC's default mitigation measures for entities that are found to have market power are ultimately applied, the Company may be required to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates. The final outcome of this matter will depend on the form in which the final methodology for assessing generation market power and mitigation rules may be ultimately adopted and cannot be determined at this time.

In addition, in May 2005, the FERC started an investigation to determine whether Southern Company satisfies the other three parts of the FERC's market-based rate analysis: transmission market power, barriers to entry, and affiliate abuse or reciprocal dealing. The FERC established a new refund period related to this expanded investigation. Any and all new market-based rate transactions both inside and outside Southern Company's retail service territory involving any Southern Company subsidiary, including the Company, will be subject to refund to the extent the FERC orders lower rates as a result of this new investigation, with the 15-month refund period beginning July 19, 2005. The impact of such sales through December 31, 2005 is not expected to exceed $10.9 million, of which $3.2 million relates to sales inside the retail service territory as discussed above. The FERC also directed that this expanded proceeding be held in abeyance pending the outcome of the proceeding on the IIC discussed below.

The Company believes that there is no meritorious basis for this proceeding and is vigorously defending itself in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in this proceeding, cannot now be determined.

Intercompany Interchange Contract

The Company's generation fleet in its retail service territory is operated under the IIC, as approved by the FERC. In May 2005, the FERC also initiated a new proceeding to examine (1) the provisions of the IIC among Alabama Power, the Company, Gulf Power, Mississippi Power, Savannah Electric, Southern Power, and SCS, as agent, under the terms of which the power pool of Southern Company is operated, and, in particular, the propriety of the continued inclusion of Southern Power as a party to the IIC, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining Southern Power as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of Southern Power, the FERC authorized Southern Power's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct. The FERC order directs that the administrative law judge who presided over the McIntosh PPA proceeding involving an approval of PPAs between Southern Power and the Company and Savannah Electric, be assigned to preside over the hearing in this proceeding and that the testimony and exhibits presented in that proceeding be preserved to the extent appropriate. Hearings are scheduled for September 2006. Effective July 19, 2005, revenues from transactions under the IIC involving any Southern Company subsidiaries, including the Company, are subject to refund to the extent the FERC orders any changes to the IIC.

The Company believes that there is no meritorious basis for this proceeding and is vigorously defending itself in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in this proceeding, cannot now be determined.

Generation Interconnection Agreements

In July 2003, the FERC issued its final rule on the standardization of generation interconnection agreements and procedures (Order 2003). Order 2003 shifts much of the financial burden of new transmission investment from the generator to the transmission provider. The FERC has indicated that Order 2003, which was effective January 20, 2004, is to be applied prospectively to interconnection

agreements. Subsidiaries of Tenaska, Inc., as counterparties to previously executed interconnection agreements with the Company and another Southern Company subsidiary, have filed complaints at the FERC requesting that the FERC modify the agreements and that the Company refund a total of $7.9 million previously paid for interconnection facilities, with interest. The Company has opposed such relief and the proceedings are still pending. The impact of Order 2003 and its subsequent rehearings on the Company and the final results of these matters cannot be determined at this time.

Race Discrimination Litigation

In July 2000, a lawsuit alleging race discrimination was filed by three of the Company's employees against the Company, Southern Company, and SCS in the Superior Court of Fulton County, Georgia. Shortly thereafter, the lawsuit was removed to the U.S. District Court for the Northern District of Georgia and amended to add four more plaintiffs. The lawsuit also raised claims on behalf of a purported class. The plaintiffs sought compensatory and punitive damages in an unspecified amount, as well as injunctive relief.

Following various court decisions in favor of the defendants and subsequent appeals by the plaintiffs, on July 13, 2005, the plaintiffs filed a petition for writ of certiorari to the U.S. Supreme Court. On October 17, 2005, the petition was denied. This matter is now concluded.

Right of Way Litigation

Southern Company and certain of its subsidiaries, including the Company, Gulf Power, Mississippi Power, and Southern Telecom, have been named as defendants in numerous lawsuits brought by landowners since 2001. 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 exceed the easements or other property rights held by defendants. The plaintiffs assert claims for, among other things, trespass and unjust enrichment, and seek compensatory and punitive damages and injunctive relief. Management believes that the Company has complied with applicable laws and that the plaintiffs' claims are without merit.

In January 2005, the Superior Court of Decatur County, Georgia granted partial summary judgment in a lawsuit brought by landowners against the Company based on the plaintiffs' declaratory judgment claim that the easements do not permit general telecommunications use. The Company appealed this ruling to the Georgia Court of Appeals. The Georgia Court of Appeals reversed, in part, the court's order and remanded the case to the trial court for the determination of further issues. After the Court of Appeals' decision, the plaintiffs filed a motion for reconsideration, which was denied, and a petition for certiorari to the Georgia Supreme Court, which is currently pending. The question of damages and other liabilities or remedies issues with respect to this action, if any, will be decided at a future trial. In the event of an adverse verdict in the case, the Company could appeal both liability and damages or other relief granted. An adverse outcome in these matters could result in substantial judgments; however, the final outcome cannot now be determined.

In addition, in late 2001, certain subsidiaries of Southern Company, including Alabama Power, the Company, Gulf Power, Mississippi Power, Savannah Electric, and Southern Telecom, were named as defendants in a lawsuit brought by a telecommunications company that uses certain of the defendants' rights of way. This lawsuit alleges, among other things, that the defendants are contractually obligated to indemnify, defend, and hold harmless the telecommunications company from any liability that may be assessed against it in pending and future right of way litigation. The Company believes that the plaintiff's claims are without merit. In the fall of 2004, the trial court stayed the case until resolution of the underlying landowner litigation discussed above. In January 2005, the Georgia Court of Appeals dismissed the telecommunications company's appeal of the trial court's order for lack of jurisdiction. An adverse outcome in this matter, combined with an adverse outcome against the telecommunications company in one or more of the right of way lawsuits, could result in substantial judgments; however, the final outcome of these matters cannot now be determined.

Property Tax Dispute

The Company is involved in a significant property tax dispute with Monroe County, Georgia (Monroe County). The Monroe County Board of Tax Assessors (Monroe Board) has issued assessments reflecting substantial

increases in the ad valorem tax valuation of the Company's 22.95 percent ownership interest in Plant Scherer, which is located in Monroe County, for tax years 2003, 2004, and 2005. The Company is aggressively pursuing administrative appeals in Monroe County and has filed notices of arbitration for all three years. The appeals are currently stayed, pending the outcome of the litigation discussed below.

In November 2004, the Company filed suit, on its behalf, against the Monroe Board in the Superior Court of Monroe County. The Company contends that Monroe County acted without statutory authority in changing the valuation of a centrally assessed utility as established by the Revenue Commissioner of the State of Georgia and requests injunctive relief prohibiting Monroe County and the Monroe Board from unlawfully changing the value of Plant Scherer and ultimately collecting additional ad valorem taxes from the Company. On December 22, 2005, the court granted Monroe County's motion for summary judgment. The Company has filed an appeal of the Superior Court's decision to the Georgia Supreme Court.

If the Company is not successful in its administrative appeals and if Monroe County is successful in defending the litigation, the Company could be subject to total additional taxes through December 31, 2005 of up to $13 million, plus penalties and interest. The ultimate outcome of this matter cannot currently be determined.

Retail Regulatory Matters

Merger

On December 13, 2005, the Company and Savannah Electric entered into an Agreement and Plan of Merger. Savannah Electric will merge into the Company, with the Company continuing as the surviving corporation (the Merger). At the effective time of the Merger, each share of the Company's common stock will remain issued and outstanding; each share of the Company's preferred stock issued and outstanding will have been redeemed prior to the Merger; the issued and outstanding shares of Savannah Electric common stock, all of which are held by Southern Company, will be converted into the right to receive 1,500,000 shares of the Company's common stock; and each share of Savannah Electric preferred stock issued and outstanding immediately prior to the Merger will be converted into the right to receive one share of a new series of the Company's Class A Preferred Stock. The Merger must be approved by the preferred shareholders of Savannah Electric and is subject to the receipt of certain regulatory approvals from the FERC, the Georgia PSC, and the Federal Communications Commission. Pending regulatory approvals, the Merger is expected to be completed by July 2006. The Merger is not expected to have a material impact on the Company's financial statements.

While the Georgia PSC does not have specific approval authority over the merger of electric utilities, the Company and Savannah Electric have filed an application with the Georgia PSC with respect to certain approvals that will be necessary to effectively complete the Merger. In particular, the Company and Savannah Electric plan to seek the approval of the Georgia PSC with respect to the following matters:

- the transfer of Savannah Electric's generating facilities and certification of the generating facilities as the Company's assets;
- amendments to the Company's Integrated Resource Plan to add the current Savannah Electric's customers and generating facilities;
- the transfer of Savannah Electric's assigned service territory to the Company;
- adoption of the Company's service rules and regulations to the current Savannah Electric customers;
- new fuel rate and base rate schedules that would apply to the Company's sale of electricity to the current Savannah Electric customers;
- adoption of a "merger transition adjustment" rate that would be used to more closely align Savannah Electric's existing base rates to those of the Company and a "merger transition credit" rate that would credit the additional revenues collected from former Savannah Electric customers to the Company's existing customers; and
- the issuance of additional shares of the Company's common stock to Southern Company in exchange for Southern Company's shares of Savannah Electric common stock.

Rate Plans

Under the terms of the 2004 Retail Rate Plan, which the Georgia PSC approved in December 2004, the Company's earnings are evaluated against a retail return on common equity (ROE) range of 10.25 percent to 12.25 percent. Two-thirds of any earnings

above 12.25 percent will be applied to rate refunds, with the remaining one-third retained by the Company. Retail rates were increased by approximately $194 million and customer fees by approximately $9 million effective January 1, 2005 to cover the higher costs of purchased power; operating and maintenance expenses; environmental compliance; and continued investment in new generation, transmission, and distribution facilities to support growth and ensure reliability. In 2005, the Company recorded $2.7 million in revenue subject to refund related to earnings in excess of 12.25 percent retail ROE.

The Company is required to file a general rate case by July 1, 2007, in response to which the Georgia PSC would be expected to determine whether the rate order should be continued, modified, or discontinued. Until then, the Company may not file for a general base rate increase unless its projected retail ROE falls below 10.25 percent.

Under the 2001 Retail Rate Plan, retail rates were decreased by $118 million effective January 1, 2002. Under the terms of the 2001 Retail Rate Plan, earnings were evaluated against a retail ROE range of 10 percent to 12.95 percent. Two-thirds of any earnings above the 12.95 percent return were to be applied to rate refunds, with the remaining one-third retained by the Company. The Company's earnings in 2004, 2003, and 2002 were within the retail ROE range.

Under the 2001 Retail Rate Plan, the Company discontinued recording accelerated depreciation and amortization and began amortizing the accumulated balance equally over three years as a credit to expense beginning in 2002. Also, the 2001 Retail Rate Plan required the Company to recognize capacity and operating and maintenance costs related to new Georgia PSC-certified PPAs evenly in rates over a three-year period ended December 31, 2004.

Fuel Hedging Program

In 2003, the Georgia PSC approved an order allowing the Company to implement a natural gas and oil procurement and hedging program. This order allows the Company to use financial instruments to hedge price and commodity risk associated with these fuels. 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 the Company retaining 25 percent of the total net gains. In 2005, the Company had a total net gain of $64.1 million, of which the Company retained $16 million.

Fuel Cost Recovery

On May 17, 2005, the Georgia PSC approved the Company's request to increase customer fuel rates by approximately 9.5 percent to recover under recovered fuel costs of approximately $508 million existing as of May 31, 2005 over a four-year period that began June 1, 2005. Based on the order, a portion of the under recovered regulatory clause revenues was reclassified from current assets to deferred charges and other assets in the balance sheet. Under recovered fuel amounts for the periods subsequent to June 1, 2005 totaled $327.5 million through December 31, 2005. The Georgia PSC's order instructs that such amounts be reviewed semi-annually beginning February 2006. If the amount under or over recovered exceeds $50 million at the evaluation date, the Company would be required to file for a temporary fuel rate change. In addition, Savannah Electric's under recovered fuel costs totaled $77.7 million at December 31, 2005. In accordance with the Georgia PSC order, Savannah Electric was scheduled to file an additional request for a fuel cost recovery increase in January 2006. The Company has agreed with a Georgia PSC staff recommendation to forego the temporary fuel rate process, and Savannah Electric has postponed its scheduled filing. Instead, the Company and Savannah Electric will file a combined request in March 2006 to increase the Company's fuel cost recovery rate.

The case will seek approval of a fuel cost recovery rate based upon future fuel cost projections for the combined Company and Savannah Electric generating fleet as well as the under recovered fuel balances existing at June 30, 2006. The new fuel cost recovery rate would be billed beginning in July 2006 to all of the Company's customers, including the existing Savannah Electric customers. Under recovered amounts as of the date of the Merger will be paid by the appropriate customer groups.

In August 2005, the Georgia PSC initiated an investigation of Savannah Electric's fuel practices. In February 2006, an investigation of the Company's fuel

practices was initiated. The Company and Savannah Electric are responding to data requests and cooperating in the investigations. The final outcome of this matter cannot now be determined.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable cost and amounts billed in current regulated rates. Accordingly, any increase in the billing factor would have no significant effect on the Company's revenues or net income, but would increase annual cash flow.

Nuclear Performance Standards

Through December 2004, the Georgia PSC had adopted a three-year performance standard for the Company's nuclear generating units. The performance standard was 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. For the period 2002-2004, the Company's performance fell within the criteria prescribed by the Georgia PSC; there was no associated award or penalty. Effective January 1, 2005, the Georgia PSC discontinued the nuclear performance standard.

Plant McIntosh Construction Project

In December 2002 after a competitive bidding process, the Georgia PSC certified PPAs between Southern Power and the Company and Savannah Electric for capacity from Plant McIntosh Units 10 and 11, construction of which was completed in June 2005. In April 2003, Southern Power applied for FERC approval of these PPAs. In July 2003, the FERC accepted the PPAs to become effective June 1, 2005, subject to refund, and ordered that hearings be held. Intervenors opposed the FERC's acceptance of the PPAs, alleging that they did not meet the applicable standards for market-based rates between affiliates. To ensure the timely completion of the Plant McIntosh construction project and the availability of the units in the summer of 2005 for their retail customers, in May 2004, the Company and Savannah Electric requested the Georgia PSC to direct them to acquire the Plant McIntosh construction project. The Georgia PSC issued such an order and the transfer occurred on May 24, 2004 at a total cost of approximately $415 million, including approximately $14 million of transmission interconnection facilities. Subsequently, Southern Power filed a request to withdraw the PPAs and to terminate the ongoing FERC proceedings. In August 2004, the FERC issued a notice accepting the request to withdraw the PPAs and permitting such request to become effective by operation of law. However, the FERC made no determination on what additional steps may need to be taken with respect to testimony provided in the proceedings. See "FERC Matters – Intercompany Interchange Contract" herein for additional information.

In connection with the 2004 Retail Rate Plan, the Georgia PSC approved the transfer of the Plant McIntosh construction project at a total fair market value of approximately $385 million. This value reflected an approximate $16 million disallowance, of which $13 million was attributable to the Company, and reduced the Company's net income by approximately $8 million. The Georgia PSC also certified a total completion cost not to exceed $547 million for the project. In June 2005, Plant McIntosh Units 10 and 11 were placed into service at a total cost that did not exceed the certified amount. Under the 2004 Retail Rate Plan, the Plant McIntosh revenue requirements impact is being reflected in the Company's rates evenly over the three years ending 2007. See "Retail Regulatory Matters—Rate Plans" herein for additional information regarding the transfer of the Plant McIntosh construction project.

4. JOINT OWNERSHIP AGREEMENTS

The Company and an affiliate, Alabama Power, own equally all of the outstanding capital stock of SEGCO which owns electric generating units with a total rated capacity of 1,020 megawatts, as well as associated transmission facilities. The capacity of 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:

	2005	2004	2003
		(in millions)	
Energy	$54	$51	$55
Capacity	38	36	34
Total	$92	$87	$89

The Company 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 (MEAG), the city of Dalton, Georgia, Florida Power & Light Company, Jacksonville Electric Authority, and Gulf Power. Under these agreements, the Company has contracted to operate and maintain the plants as agent for the co-owners and 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 combustion- turbine common facilities and Plant McIntosh combined cycle units with Savannah Electric who operates the plants. The Company and Progress Energy Florida, Inc. jointly own a combustion turbine unit (Intercession City) operated by Progress Energy Florida, Inc.

At December 31, 2005, 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%	$3,311*	$1,809
Plant Hatch (nuclear)	50.1	935	492
Plant Wansley (coal)	53.5	395	172
Plant Scherer (coal)			
Units 1 and 2	8.4	115	56
Unit 3	75.0	562	270
Plant McIntosh CC (combined cycle)	83.9	436	7
Plant McIntosh Common Facilities (combustion-turbine)	75.0	27	5
Rocky Mountain (pumped storage)	25.4	169*	92
Intercession City (combustion-turbine)	33.3	12	2

*Investment includes write-offs

At December 31, 2005, the portion of total construction work in progress related to Plants Wansley, Scherer, and Rocky Mountain was $8.3 million, $0.5 million, and $0.1 million, respectively, primarily for environmental projects.

The Company's proportionate share of its plant operating expenses is included in the corresponding operating expenses in the statements of income.

5. INCOME TAXES

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

In 2004, in order to avoid the loss of certain federal income tax credits related to the production of synthetic fuel, Southern Company chose to defer certain

deductions otherwise available to the subsidiaries. The cash flow benefit associated with the utilization of the tax credits was allocated to the subsidiary that otherwise would have claimed the available deductions on a separate company basis without the deferral. This allocation concurrently reduced the tax benefit of the credits allocated to those subsidiaries that generated the credits. As the deferred expenses are deducted, the benefit of the tax credits will be repaid to the subsidiaries that generated the tax credits. The Company has recorded $10 million payable to these subsidiaries in Accumulated Deferred Income Taxes on the balance sheets at December 31, 2005.

The transfer of the Plant McIntosh construction project from Southern Power to the Company resulted in a deferred gain to Southern Power for federal income tax purposes. The Company will reimburse Southern Power for the remaining balance of the related deferred taxes of $5.3 million reflected in Southern Power's future taxable income. $3.7 million of this payable to Southern Power is included in Other Deferred Credits and $1.6 million is included in Affiliated Accounts Payable in the balance sheet at December 31, 2005.

The transfer of the Dahlberg, Wansley, and Franklin projects to Southern Power from the Company in 2001 and 2002 also resulted in a deferred gain for federal income tax purposes. Southern Power will reimburse the Company for the remaining balance of the related deferred taxes of $12.2 million reflected in the Company's future taxable income. $10.8 million of this receivable from Southern Power is included in Other Deferred Debits and $1.4 million is included in Affiliated Accounts Receivable in the balance sheet at December 31, 2005.

At December 31, 2005, tax-related regulatory assets were $501 million and tax-related regulatory liabilities were $159 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:

	2005	2004	2003
Total provision for income taxes:		(in millions)	
Federal:			
Current	**$173**	$116	$143
Deferred	**203**	221	181
	376	337	324
State:			
Current	**26**	12	24
Deferred	**29**	30	16
Deferred investment tax credits	**-**	-	2
Total	**$431**	$379	$366

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:

	2005	2004
	(in millions)	
Deferred tax liabilities:		
Accelerated depreciation	**$2,177**	$2,050
Property basis differences	**558**	577
Employee benefit obligations	**163**	149
Fuel clause under recovery	**305**	141
Premium on reacquired debt	**69**	72
Storm damage reserve	**13**	6
Other	**74**	81
Total	**3,359**	3,076
Deferred tax assets:		
Federal effect of state deferred taxes	**116**	106
Other property basis differences	**139**	147
Other deferred costs	**126**	94
Employee benefit obligations	**51**	55
Other comprehensive income	**23**	22
Unbilled revenue	**13**	11
Other	**33**	19
Total	**501**	454
Total deferred tax liabilities, net	**2,858**	2,622
Portion included in current (liabilities) assets, net	**(128)**	(66)
Accumulated deferred income taxes in the balance sheets	**$2,730**	$2,556

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 2005, $12 million in 2004, and $15 million in 2003. At December 31, 2005, all investment tax credits available to reduce federal income taxes payable had been utilized.

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

	2005	2004	2003
Federal statutory rate	35%	35%	35%
State income tax, net of federal deduction	3	3	3
Non-deductible book depreciation	1	1	1
Other	(1)	(2)	(2)
Effective income tax rate	38%	37%	37%

6. FINANCING

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

The Company has formed certain wholly owned trust subsidiaries for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the Company through the issuance of junior subordinated notes totaling $969 million, which constitute substantially all of the assets of the trusts and are reflected in the balance sheets as Long-Term Debt Payable to Affiliated Trusts. The Company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the respective trusts' payment obligations with respect to these securities. At December 31, 2005, preferred securities of $940 million were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for these trusts and the related securities.

Securities Due Within One Year

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

	2005	2004
	(in millions)	
Capital lease	$ 3	$ 2
Senior notes	150	450
Preferred stock	15	-
Total	$168	$452

Serial maturities through 2010 applicable to total long-term debt and preferred stock are as follows: $168 million in 2006; $303 million in 2007; $3 million in 2008; $278 million in 2009; and $4 million in 2010.

Pollution Control Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such 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, 2005 was $1.7 billion.

Senior Notes

The Company issued a total of $625 million of unsecured senior notes in 2005. The proceeds of these issues were used to redeem or repay at maturity long-term debt, to repay short-term indebtedness, and for other general corporate purposes. At December 31, 2005 and 2004, the Company had $2.6 billion and $2.4 billion of senior notes outstanding, respectively. These senior notes are subordinate to all secured debt of the Company.

Capital Leases

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, 2005 and 2004, the Company had a capitalized lease obligation for its corporate headquarters

building of $74 million and $77 million, respectively, with an interest rate of 8.1 percent. For ratemaking purposes, the Georgia PSC 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 Georgia PSC. See Note 1 under "Regulatory Assets and Liabilities."

Bank Credit Arrangements

At the beginning of 2006, the Company had credit arrangements with banks totaling $780 million, of which $778 million was unused. Of these facilities, $70 million expires at various times throughout 2006; $350 million expires in 2007, with the remaining $360 million expiring in 2010. The facilities that expire in 2006 provide the option of converting borrowings into a two-year term loan. The Company expects to renew its facilities, as needed, prior to expiration. The agreements contain stated borrowing rates. All the agreements require payment of commitment fees based on the unused portion 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. A fee is also paid to the agent bank.

The credit arrangements contain covenants that limit the level of indebtedness to capitalization to 65 percent, as defined in the arrangements. For purposes of these definitions, indebtedness excludes the long-term debt payable to affiliated trusts. In addition, the credit arrangements contain cross default provisions that would trigger an event of default if the Company defaulted on other indebtedness above a specified threshold. At December 31, 2005, the Company was in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowings.

The $778 million 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, 2005 was $106 million. In addition, the Company borrows under a commercial paper program and an extendible commercial note program. The amount of commercial paper outstanding at December 31, 2005 was $268 million. The amount of commercial paper outstanding at December 31, 2004 was $208 million. There were no outstanding extendible commercial notes at December 31, 2005. Commercial paper is included in notes payable on the balance sheets.

During 2005, the peak amount of short-term debt outstanding was $549 million and the average amount outstanding was $242 million. The average annual interest rate on short-term debt in 2005 was 3.20 percent.

Financial Instruments

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. See Note 3 under "Retail Regulatory Matters – Fuel Hedging Program" for information on the Company's fuel hedging program. The Company also enters into hedges of forward electricity sales. There was no material ineffectiveness recorded in earnings in 2005, 2004, and 2003.

At December 31, 2005, the fair value of derivative energy contracts was reflected in the financial statements as follows:

	Amounts
	(in thousands)
Regulatory liabilities, net	$26,643
Other comprehensive income	-
Net income	(81)
Total fair value	$26,562

The fair value gain or loss for hedges that are recoverable through the regulatory fuel clauses are recorded in regulatory assets and liabilities and are recognized in earnings at the same time the hedged items affect earnings. The Company has energy-related hedges in place up to and including 2008.

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

addition to interest rate swaps, the Company has also entered into certain options agreements that effectively cap its interest rate exposure in return for payment of a premium. In some cases, costless collars have been used that effectively establish a floor and a ceiling to interest rate expense.

At December 31, 2005, the Company had $1.0 billion notional amounts of interest derivatives accounted for as cash flow hedges outstanding with net fair value gains as follows:

Maturity	Weighted Average Fixed Rate Paid	Notional Amount	Fair Value Gain / (Loss)
		(in millions)	
2007	2.67%	$300	$ 2.4
2006-2007	2.09% -3.85%*	$400	$ 1.2
2037	4.58% -5.75%**	$300	$(1.1)

*Series of interest rate caps and collars (showing the lowest floor and highest cap) with variable rate based on one-month LIBOR
**Interest rate collar

The fair value gain or loss for cash flow hedges is recorded in other comprehensive income and is reclassified into earnings at the same time the hedged items affect earnings. In 2005, 2004, and 2003, the Company settled gains (losses) totaling $0.9 million, $(12.4) million, and $(11.3) million, respectively, upon termination of certain interest derivatives at the same time it issued debt. For the years 2005, 2004, and 2003, approximately $1.9 million, $3.9 million, and $3.4 million, respectively, of pre-tax losses were reclassified from other comprehensive income to interest expense. For 2006, pre-tax losses of approximately $0.5 million are expected to be reclassified from other comprehensive income to interest expense. The Company has gains/losses that are being amortized through 2017.

7. COMMITMENTS

Construction Program

The Company currently estimates property additions to be approximately $1.3 billion, $1.4 billion, and $1.3 billion in 2006, 2007, and 2008, respectively. These amounts include $44 million, $28 million, and $14 million in 2006, 2007, and 2008, respectively, for construction expenditures related to contractual purchase commitments for uranium and nuclear fuel conversion, enrichment, and fabrication services included under "Fuel Commitments" herein. 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, changes in FERC rules and transmission regulations, 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, 2005, significant purchase commitments were outstanding in connection with the construction program.

The Company completed construction of Plant McIntosh Units 10 and 11 in June 2005 and has no other generating plants currently under construction. Construction related to new transmission and distribution facilities and capital improvements to existing generation, transmission and distribution facilities, including those needed to meet environmental standards, is ongoing.

Long-Term Service Agreements

The Company and Savannah Electric have entered into a Long-Term Service Agreement (LTSA) with General Electric (GE) for the purpose of securing maintenance support for the combustion turbines at the Plant McIntosh combined cycle facility. In summary, the LTSA stipulates that GE will perform all planned inspections on the covered equipment, which includes the cost of all labor and materials. GE is also obligated to cover the costs of unplanned maintenance on the covered equipment subject to a limit specified in each contract.

In general, this LTSA is in effect through two major inspection cycles per unit. Scheduled payments to GE are made at various intervals based on actual operating hours of the respective units. Total payments to GE under this agreement are currently estimated at $186 million over the remaining term of the agreement, which may range up to 30 years. However, the LTSA contains various cancellation provisions at the option of the Company.

The Company has also entered into an LTSA with GE through 2014 for neutron monitoring system parts and electronics at Plant Hatch. Total remaining payments to GE under this agreement are currently estimated at $13.1 million. The contract contains

cancellation provisions at the option of the Company.

Payments made to GE prior to the performance of any work are recorded as a prepayment in the balance sheets. Work performed by GE is capitalized or charged to expense as appropriate net of any joint owner billings, based on the nature of the work.

Fuel Commitments

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement of fossil and nuclear fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Coal commitments include forward contract purchases for sulfur dioxide emission allowances. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery. Amounts included in the chart below represent estimates based on New York Mercantile Exchange future prices at December 31, 2005.

Total estimated minimum long-term obligations at December 31, 2005 were as follows:

	Commitments		
	Natural Gas	Coal	Nuclear Fuel
		(in millions)	
2006	$577	$1,579	$ 44
2007	325	1,313	28
2008	200	907	14
2009	257	422	11
2010	254	272	14
2011 and thereafter	2,047	40	64
Total	$3,660	$4,533	$175

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

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other Southern Company retail operating companies, Southern Power, and Southern Company Gas. Under these agreements, each of the retail operating companies, Southern Power, and Southern Company Gas may be jointly and severally liable. The creditworthiness of Southern Power and Southern Company Gas is currently inferior to the creditworthiness of the retail operating companies. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the retail 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 Company Gas as a contracting party under these agreements.

Purchased Power Commitments

The Company has commitments regarding a portion of a 5 percent interest in Plant Vogtle owned by 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 $54 million, $55 million, and $57 million in 2005, 2004, and 2003, respectively. The current projected Plant Vogtle capacity payments are:

	Capacity Payments
	(in millions)
2006	$ 53
2007	52
2008	54
2009	54
2010	54
2011 and thereafter	261
Total	$528

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 at the time of the disallowance was written off.

The Company has entered into other various long-term commitments for the purchase of electricity. Estimated total long-term obligations under these

commitments at December 31, 2005 were as follows:

	Commitments	
	Affiliated	Non-Affiliated
	(in millions)	
2006	$205	$85
2007	205	86
2008	205	87
2009	205	68
2010	112	66
2011 and thereafter	455	278
Total	$1,387	$670

Operating Leases

The Company has entered into various operating leases with various terms and expiration dates. Rental expenses related to these operating leases totaled $38 million for 2005, $38 million for 2004, and $36 million for 2003.

At December 31, 2005, estimated minimum lease payments for these noncancelable operating leases were as follows:

	Minimum Lease Payments		
	Rail Cars	Other	Total
	(in millions)		
2006	$ 17	$ 17	$ 34
2007	17	14	31
2008	16	11	27
2009	15	9	24
2010	14	6	20
2011 and thereafter	48	10	58
Total	$127	$67	$194

In addition to the rental commitments above, the Company has obligations upon expiration of certain rail car leases with respect to the residual value of the leased property. These leases expire in 2011 and the Company's maximum obligation is $68 million. 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 rail car lease obligations is shared with the joint owners of plants Scherer and Wansley. Rental expenses related to the rail car leases are fully recoverable through the fuel cost recovery clause as ordered by the Georgia PSC.

Guarantees

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. Alabama Power has also guaranteed $50 million in senior notes issued by SEGCO. The Company has agreed to reimburse Alabama Power for the pro rata portion of such obligations corresponding to the Company'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.

8. STOCK OPTION PLAN

Southern Company provides non-qualified stock options to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2005, 1,551 current and former employees of the Company participated in the stock option plan. The maximum number of shares of Southern Company common stock that may be issued under this plan may not exceed 55 million. The prices of options granted to date have been at the fair market value of the shares on the dates of grant. Options granted to date become exercisable pro rata over a maximum period of three years from the date of grant. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the stock option plan. Activity from 2003 to 2005 for the options granted

to the Company's employees under the stock option plan is summarized below:

	Shares Subject To Option	Average Option Price Per Share
Balance at December 31, 2002	7,178,597	$19.73
Options granted	1,455,517	27.98
Options canceled	(54,860)	25.47
Options exercised	(1,428,273)	16.92
Balance at December 31, 2003	7,150,981	21.92
Options granted	1,434,915	29.50
Options canceled	(6,371)	25.99
Options exercised	(1,450,309)	18.25
Balance at December 31, 2004	**7,129,216**	**24.19**
Options granted	**1,427,618**	**32.71**
Options canceled	**(12,910)**	**23.75**
Options exercised	**(1,838,033)**	**21.23**
Balance at December 31, 2005	**6,705,891**	**$26.82**

Options exercisable:	
At December 31, 2003	3,956,234
At December 31, 2004	4,304,091
At December 31, 2005	**3,989,722**

The following table summarizes information about options outstanding at December 31, 2005:

	Dollar Price Range of Options		
	13-21	21-28	28-35
Outstanding:			
Shares (in thousands)	991	2,922	2,794
Average remaining life (in years)	4.2	6.0	8.5
Average exercise price	$17.25	$25.94	$31.13
Exercisable:			
Shares (in thousands)	991	2,496	503
Average exercise price	$17.25	$25.59	$29.75

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act, the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the Company's nuclear power plants. The Act provides funds up to $10.76 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 $101 million per incident for each licensed reactor it operates but not more than an aggregate of $15 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 $203 million per incident but not more than an aggregate of $30 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 up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. The Company purchases the maximum limit allowed by NEIL 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 NEIL policies would be $48 million.

Following the terrorist attacks of September 2001, both ANI and NEIL confirmed that terrorist acts against commercial nuclear power plants would, subject to the normal policy limits, be covered under their insurance. Both companies, however, revised their policy terms on

a prospective basis to include an industry aggregate for all "non-certified" terrorist acts i.e., acts that are not certified acts of terrorism pursuant to the Terrorism Risk Insurance Act of 2002, which was renewed in 2005. The aggregate for all NEIL policies, which applies to non-certified property claims stemming from terrorism within a 12-month duration, is $3.24 billion plus any amounts available through reinsurance or indemnity from an outside source. The non-certified ANI nuclear liability cap is a $300 million shared industry aggregate during the normal ANI policy period.

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

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

10. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2005 and 2004 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred Stock
		(in millions)	
March 2005	**$1,370**	**$286**	**$142**
June 2005	**1,459**	**311**	**158**
September 2005	**2,219**	**626**	**355**
December 2005	**1,586**	**165**	**60**
March 2004	$1,199	$285	$144
June 2004	1,353	322	156
September 2004	1,582	486	287
December 2004	1,237	166	71

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

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SELECTED FINANCIAL AND OPERATING DATA 2001-2005

Georgia Power Company 2005 Annual Report

	2005	2004	2003	2002	2001
Operating Revenues (in thousands)	$6,634,203	$5,370,808	$4,913,507	$4,822,460	$4,965,794
Net Income after Dividends on Preferred Stock (in thousands)	$714,999	$658,001	$630,577	$617,629	$610,335
Cash Dividends on Common Stock (in thousands)	$556,100	$565,500	$565,800	$542,900	$527,300
Return on Average Common Equity (percent)	14.15	13.95	14.05	13.99	14.12
Total Assets (in thousands)	$17,047,783	$15,822,338	$14,850,754	$14,342,656	$14,447,973
Gross Property Additions (in thousands)	$906,248	$1,126,064	$742,810	$883,968	$1,389,751
Capitalization (in thousands):					
Common stock equity	$5,214,535	$4,890,561	$4,540,211	$4,434,447	$4,397,485
Preferred stock	-	14,609	14,569	14,569	14,569
Mandatorily redeemable preferred securities	-	-	940,000	940,000	789,250
Long-term debt payable to affiliated trusts	969,073	969,073	-	-	-
Long-term debt	4,179,218	3,709,852	3,762,333	3,109,619	2,961,726
Total (excluding amounts due within one year)	$10,362,826	$9,584,095	$9,257,113	$8,498,635	$8,163,030
Capitalization Ratios (percent):					
Common stock equity	50.3	51.0	49.0	52.2	53.9
Preferred stock	-	0.2	0.2	0.2	0.2
Mandatorily redeemable preferred securities	-	-	10.2	11.1	9.6
Long-term debt payable to affiliated trusts	9.4	10.1	-	-	-
Long-term debt	40.3	38.7	40.6	36.5	36.3
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0
Security Ratings:					
Preferred Stock -					
Moody's	Baa1	Baa1	Baa1	Baa1	Baa1
Standard and Poor's	BBB+	BBB+	BBB+	BBB+	BBB+
Fitch	A	A	A	A	A
Unsecured Long-Term Debt -					
Moody's	A2	A2	A2	A2	A2
Standard and Poor's	A	A	A	A	A
Fitch	A+	A+	A+	A+	A+
Customers (year-end):					
Residential	1,832,520	1,801,426	1,768,662	1,734,430	1,698,407
Commercial	270,373	265,543	258,276	250,993	244,674
Industrial	8,206	7,676	7,899	8,240	8,046
Other	3,536	3,482	3,434	3,328	3,239
Total	2,114,635	2,078,127	2,038,271	1,996,991	1,954,366
Employees (year-end)	8,713	8,731	8,714	8,837	9,048

N/A = Not Applicable.

SELECTED FINANCIAL AND OPERATING DATA 2001-2005 (continued)
Georgia Power Company 2005 Annual Report

	2005	2004	2003	2002	2001
Operating Revenues (in thousands):					
Residential	$ 2,024,204	$1,736,072	$1,583,082	$1,600,438	$1,507,031
Commercial	2,206,252	1,812,096	1,661,054	1,631,130	1,682,918
Industrial	1,351,731	1,172,936	1,012,267	1,004,288	1,106,420
Other	60,625	55,881	53,569	52,241	52,943
Total retail	5,642,812	4,776,985	4,309,972	4,288,097	4,349,312
Sales for resale - non-affiliates	519,673	246,545	259,376	270,678	366,085
Sales for resale - affiliates	264,989	166,245	174,855	98,323	99,411
Total revenues from sales of electricity	6,427,474	5,189,775	4,744,203	4,657,098	4,814,808
Other revenues	206,729	181,033	169,304	165,362	150,986
Total	$6,634,203	$5,370,808	$4,913,507	$4,822,460	$4,965,794
Kilowatt-Hour Sales (in thousands):					
Residential	23,585,115	22,930,372	21,778,582	22,144,559	20,119,080
Commercial	29,768,402	28,014,357	26,940,572	26,954,922	26,493,255
Industrial	25,027,371	26,357,271	25,703,421	25,739,785	25,349,477
Other	601,330	602,202	595,742	593,202	583,007
Total retail	78,982,218	77,904,202	75,018,317	75,432,468	72,544,819
Sales for resale - non-affiliates	11,234,527	5,969,983	8,835,804	8,069,375	8,110,096
Sales for resale - affiliates	4,854,914	4,782,873	5,844,196	3,962,559	3,133,485
Total	95,071,659	88,657,058	89,698,317	87,464,402	83,788,400
Average Revenue Per Kilowatt-Hour (cents):					
Residential	8.58	7.57	7.27	7.23	7.49
Commercial	7.41	6.47	6.17	6.05	6.35
Industrial	5.40	4.45	3.94	3.90	4.36
Total retail	7.14	6.13	5.75	5.68	6.00
Sales for resale	4.88	3.84	2.96	3.07	4.14
Total sales	6.76	5.85	5.29	5.32	5.75
Residential Average Annual Kilowatt-Hour Use Per Customer	12,974	12,838	12,421	12,867	11,933
Residential Average Annual Revenue Per Customer	$1,113	$972	$903	$930	$894
Plant Nameplate Capacity Ratings (year-end) (megawatts)	15,097	13,978	13,980	14,059	14,474
Maximum Peak-Hour Demand (megawatts):					
Winter	13,501	12,208	13,153	11,873	11,977
Summer	15,953	15,180	14,826	14,597	14,294
Annual Load Factor (percent)	59.7	61.5	61.0	60.4	61.7
Plant Availability (percent):					
Fossil-steam	90.7	90.3	87.6	80.9	88.5
Nuclear	89.3	94.8	94.2	88.8	94.4
Source of Energy Supply (percent):					
Coal	60.8	57.9	58.6	59.5	58.5
Nuclear	15.1	17.3	16.8	16.2	18.1
Hydro	1.9	1.5	2.1	0.9	1.1
Oil and gas	2.9	0.1	0.3	0.3	0.4
Purchased power -					
From non-affiliates	5.7	7.0	7.5	6.3	7.8
From affiliates	13.6	16.2	14.7	16.8	14.1
Total	100.0	100.0	100.0	100.0	100.0

DIRECTORS AND OFFICERS
Georgia Power Company 2005 Annual Report

Directors

Juanita Powell Baranco
Executive Vice President
Baranco Acura
(Resigned effective 2/21/2006)

Gus H. Bell, III – *Nominee*
Chairman, President and Chief Executive Officer
Hussey, Gay, Bell and DeYoung - A Bell Company

Robert L. Brown, Jr.
President and Chief Executive Officer
R. L. Brown & Associates, Inc.

Ronald D. Brown
President and Chief Executive Officer
Atlanta Life Financial Group

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

Michael D. Garrett
President and Chief Executive Officer
Georgia Power Company

David M. Ratcliffe
President and Chief Executive Officer
The Southern Company

D. Gary Thompson
Retired from
Wachovia Corporation

Richard W. Ussery
Retired from
Total System Services (TSYS)

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

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

Officers

Michael D. Garrett
President and Chief Executive Officer
Georgia Power Company

William C. Archer, III
Executive Vice President
External Affairs
(Retirement effective 3/19/2006)

Mickey A. Brown
Executive Vice President
Customer Service Organization

Cliff S. Thrasher
Executive Vice President, Chief Financial Officer
and Treasurer

Christopher C. Womack
Executive Vice President (Effective 3/11/2006)
External Affairs

Judy M. Anderson
Senior Vice President
Charitable Giving

Richard L. Holmes
Senior Vice President
Metro Region

E. Lamont Houston
Senior Vice President (Effective 1/14/2006)
Customer Service and Sales

Douglas E. Jones
Senior Vice President (Effective 3/11/2006)
Fossil and Hydro Generation

James H. Miller III
Senior Vice President and
General Counsel

Leslie R. Sibert
Vice President
Transmission

Gene L. Ussery
Vice President
Distribution

DIRECTORS AND OFFICERS

Georgia Power Company 2005 Annual Report

Michael K. Anderson
Vice President (Effective 1/14/2006)
Corporate Services

W. Craig Barrs
Vice President

Robert A. Bell
Vice President (Effective 2/15/2006)
Human Resources

Rebecca A. Blalock
Vice President
Information Technology

P. Mike Clanton
Vice President (Effective 1/14/2006)
Customer Service

Ann P. Daiss
Vice President, Comptroller and
Chief Accounting Officer (Effective 3/11/2006)

Walter Dukes
Region Vice President
East

A. Bryan Fletcher
Vice President
Supply Chain Management

J. Kevin Fletcher
Vice President
Community and Economic Development

Jeff G. Franklin
Region Vice President
Northwest

Oscar C. Harper IV
Vice President (Effective 2/11/2006)
Resource Planning and Nuclear Development

O. Ben Harris
Vice President
Land

W. Ron Hinson
Vice President, Comptroller and
Chief Accounting Officer (Resigned effective
3/11/2006)

Ed F. Holcombe
Vice President
Governmental and Regulatory Affairs

Charles H. Huling
Vice President
Environmental Affairs

Anne H. Kaiser
Vice President
Sales

Ellen N. Lindemann
Vice President (Resigned effective 2/1/2006)
Human Resources

Jacki W. Lowe
Region Vice President
West

Daniel M. Lowery
Corporate Secretary

Terri H. Lupo
Region Vice President
South

Frank J. McCloskey
Vice President
Diversity

Robert B. Morris
Assistant Comptroller and Assistant Secretary

James E. Sykes, Jr.
Region Vice President
Northeast

Mark K. Tate
Assistant Comptroller

Jeff L. Wallace
Vice President (Resigned effective 2/11/2006)
Planning and Utility Relations

Thomas J. Wicker
Region Vice President
Central

W. Tal Wright
Vice President
Corporate Communication

Wayne Boston
Assistant Secretary and
Assistant Treasurer

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

Profile
The Company produces and delivers electricity as an integrated utility to retail customers within the State of Georgia and to wholesale customers in the Southeast. The Company sells electricity to approximately 2.1 million customers within its service area of approximately 57,000 square miles. In 2005, retail energy sales accounted for 83 percent of the Company's total sales of 95.1 billion kilowatt-hours.

The Company is a wholly owned subsidiary of The Southern Company, which is the parent company of five retail operating companies and a wholesale generation subsidiary, as well as other direct and indirect subsidiaries. There is no established public trading market for the Company's common stock.

Trustee, Registrar and Interest Paying Agent
All series of Senior Notes and Trust Preferred Securities
JPMorgan Chase Bank, N.A.
Institutional Trust Services
4 New York Plaza, 15th Floor
New York, NY 10004

Number of Preferred Shareholders of record as of December 31, 2005, was 1,003.

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

Georgia Power Company
241 Ralph McGill Boulevard, N.E.
Atlanta, GA 30308-3374
(404) 506-6526

Auditors
Deloitte & Touche LLP
Suite 1500
191 Peachtree Street, N.E.
Atlanta, GA 30303

Legal Counsel
Troutman Sanders LLP
600 Peachtree Street, N.E.
Suite 5200
Atlanta, GA 30308

GEORGIA POWER
A SOUTHERN COMPANY

July 28, 2006

Docket Nos.: 50-321 50-424
50-366 50-425
72-36

NL-06-1486

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
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 2005.

2. A set of quarterly financial statements for the period ending June 30, 2006.

3. A one year projected Cash Flows Statement for period January 1, 2007, through December 31, 2007.

Should you have any questions in connection with our response, please contact me at (404) 506-7952 or Jan Miller at (404) 506-6690. This letter contains no NRC commitments.

Sincerely,

Robert A. Aubuchon

Enclosures

cc: Southern Nuclear Operating Company
Mr. J. T. Gasser, Executive Vice President
Mr. L. M. Stinson, Vice President, Plant Hatch
Mr. D. E. Grissette, Vice President, Plant Vogtle
Mr. D. R. Madison, General Manager – Plant Hatch
Mr. T. E. Tynan, General Manager – Plant Vogtle
RType: CHA02.004; CVC7000

U. S. Nuclear Regulatory Commission
Dr. W. D. Travers, Regional Administrator
Mr. C. Gratton, NRR Project Manager – Hatch
Mr. C. Gratton, NRR Project Manager – Vogtle
Mr. D. S. Simpkins, Senior Resident Inspector – Hatch
Mr. G. J. McCoy, Senior Resident Inspector – Vogtle

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2006	2005	2006	2005
OPERATING REVENUES:				
Retail sales	$1,420,762	$1,227,087	$2,687,718	$2,412,323
Sales for resale–				
Non-affiliates	132,557	126,000	265,921	238,852
Affiliates	85,674	54,743	120,616	80,374
Other revenues	59,745	51,358	111,932	98,069
Total operating revenues	1,698,738	1,459,188	3,186,187	2,829,618
OPERATING EXPENSES:				
Operation–				
Fuel	556,691	412,050	991,465	721,316
Purchased power–				
Non-affiliates	82,321	64,523	138,876	117,497
Affiliates	145,518	140,800	336,037	360,804
Other	226,256	223,471	444,976	425,550
Maintenance	119,876	123,575	239,176	240,225
Depreciation and amortization	117,590	124,999	235,447	248,099
Taxes other than income taxes	68,945	58,648	136,090	119,407
Total operating expenses	1,317,197	1,148,066	2,522,067	2,232,898
OPERATING INCOME	381,541	311,122	664,120	596,720
OTHER INCOME (EXPENSE):				
Allowance for equity funds used during construction	6,338	7,935	12,123	17,192
Interest income	199	31	515	502
Interest expense, net of amounts capitalized	(61,322)	(55,174)	(121,529)	(105,594)
Interest expense to affiliate trusts	(14,877)	(14,877)	(29,755)	(29,755)
Other income (expense), net	3,370	2,821	2,376	(21)
Total other income and (expense)	(66,292)	(59,264)	(136,270)	(117,676)
EARNINGS BEFORE INCOME TAXES	315,249	251,858	527,850	479,044
Income taxes	119,059	94,140	199,003	178,794
NET INCOME	196,190	157,718	328,847	300,250
DIVIDENDS ON PREFERRED STOCK	-	167	1,010	335
NET INCOME AFTER DIVIDENDS ON PREFERRED STOCK	$196,190	$157,551	$327,837	$299,915

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, 2006	At June 30, 2005
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$11,422	$9,294
Receivables --		
Customer accounts receivable	416,118	361,605
Unbilled revenues	176,184	168,392
Under recovered regulatory clause revenue	372,587	153,301
Other accounts and notes receivable	85,136	185,223
Affiliated companies	55,814	31,350
Accumulated provision for uncollectible accounts	(8,521)	(6,575)
Fossil fuel stock, at average cost	262,620	207,959
Materials and supplies, at average cost	352,866	286,446
Other	174,706	91,819
Total Current Assets	1,898,932	1,488,814
PROPERTY, PLANT AND EQUIPMENT:		
In service	19,957,393	19,327,416
Less accumulated provision for depreciation	7,775,166	7,392,744
	12,182,227	11,934,672
Nuclear fuel, at amortized cost	148,604	129,567
Construction work in progress	599,874	443,904
Total Property, Plant and Equipment	12,930,705	12,508,143
OTHER PROPERTY AND INVESTMENTS:		
Equity investments in unconsolidated subsidiaries	68,470	65,949
Nuclear decommissioning trusts	499,868	466,656
Other	70,800	64,472
Total Other Property and Investments	639,138	597,077
DEFERRED CHARGES AND OTHER ASSETS:		
Deferred charges related to income taxes	497,775	506,259
Prepaid pension costs	487,462	460,865
Unamortized debt issuance expense	84,515	88,638
Unamortized loss on reacquired debt	165,650	172,961
Deferred under recovered regulatory clause revenues	477,611	362,692
Other	255,106	170,698
Total Deferred Charges and Other Assets	1,968,119	1,762,113
TOTAL ASSETS	$17,436,894	$16,356,147

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

	At June 30, 2006	At June 30, 2005
LIABILITIES AND STOCKHOLDER'S EQUITY		
CURRENT LIABILITIES:		
Securities due within one year	$2,822	$402,603
Notes payable	657,559	379,902
Accounts payable –		
Affiliated companies	207,585	157,765
Other	292,313	248,786
Customer deposits	140,292	122,446
Taxes accrued		
Income taxes	313,302	183,985
Other	146,254	115,596
Interest accrued	74,533	78,595
Vacation pay accrued	45,692	44,179
Other	210,770	186,640
Total Current Liabilities	2,091,122	1,920,497
LONG-TERM DEBT	4,177,916	3,931,825
LONG-TERM DEBT PAYABLE TO AFFILIATED TRUSTS	969,073	969,073
DEFERRED CREDITS AND OTHER LIABILITIES:		
Accumulated deferred income taxes	2,693,006	2,598,783
Deferred credits related to income taxes	153,196	164,588
Accumulated deferred investment tax credits	281,581	293,872
Employee benefits provisions	379,656	346,916
Asset retirement obligations	647,003	520,298
Other	548,023	581,077
Total Deferred Credits and Other Liabilities	4,702,465	4,505,534
PREFERRED STOCK	-	14,609
COMMON STOCKHOLDER'S EQUITY:		
Common stock	344,250	344,250
Paid-in capital	2,880,563	2,589,121
Retained earnings	2,288,285	2,124,641
Accumulated other comprehensive income	(16,780)	(43,403)
Total Common Stockholder's Equity	5,496,318	5,014,609
TOTAL LIABILITIES AND STOCKHOLDER'S EQUITY	$17,436,894	$16,356,147

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

	FOR THE SIX MONTHS ENDED JUNE	
	2006	2005
OPERATING ACTIVITIES:		
Net income	$328,847	$300,250
Adjustments to reconcile net income to net cash provided by operating activities --		
Depreciation and amortization	276,048	292,447
Deferred income taxes and investment tax credits, net	13,433	89,724
Deferred expenses - affiliated	18,717	20,302
Allowance for funds used during construction	(12,123)	(17,192)
Pension, postretirement, and other employee benefits	(1,225)	5,318
Stock option expense	4,330	-
Other, net	8,729	(1,058)
Changes in certain current assets and liabilities --		
Receivables, net	(89,773)	(247,991)
Fossil fuel stock	(80,881)	(23,692)
Materials and supplies	(28,885)	(16,024)
Other current assets	49,999	14,055
Accounts payable	(128,890)	(59,236)
Taxes accrued	38,209	43,098
Other current liabilities	(76,833)	(42,595)
NET CASH PROVIDED FROM OPERATING ACTIVITIES	319,702	357,406
INVESTING ACTIVITIES:		
Gross property additions	(448,857)	(381,191)
Nuclear decommissioning trust fund purchases	(241,021)	(205,261)
Nuclear decommissioning trust fund sales	234,141	196,562
Cost of removal net of salvage	(10,658)	(10,359)
Other	(9,099)	(33,274)
NET CASH USED FOR INVESTING ACTIVITIES	(475,494)	(433,523)
FINANCING ACTIVITIES:		
Increase (decrease) in notes payable, net	389,817	171,669
Proceeds --		
Senior notes	-	375,000
Pollution control bonds	10,125	185,000
Capital contributions from parent company	232,328	100,000
Gross excess tax benefit of stock options	611	-
Redemptions --		
Pollution control bonds	(10,125)	(85,000)
Senior notes	(150,000)	(300,000)
Preferred stock	(14,569)	
Special deposits - redemption funds	-	(100,000)
Payment of preferred stock dividends	(12)	(211)
Payment of common stock dividends	(301,250)	(278,050)
Other	(347)	(16,494)
NET CASH PROVIDED FROM FINANCING ACTIVITIES	156,578	51,914
NET CHANGE IN CASH AND CASH EQUIVALENTS	786	(24,203)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	10,636	33,497
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$11,422	$9,294

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

GEORGIA POWER COMPANY
PROJECTED STATEMENT OF CASH FLOWS
2007 FORECAST
(Stated in Thousands of Dollars)

	2007 FORECAST
OPERATING ACTIVITIES	
Net income before preferred dividends	$831,346
Principal noncash items-	
Depreciation and amortization	622,394
Deferred income taxes, net	(26,943)
Allowance for equity funds used during construction	(71,263)
Pension, postretirement and other employee benefits	(16,032)
Other, net	230,590
Change in current assets & liabilities-	
Receivables	(36,755)
Inventories	10,331
Accounts payable	9,114
Other current assets and liabilities	95,611
NET CASH PROVIDED FROM OPERATING ACTIVITIES	1,648,393
INVESTING ACTIVITIES	
Gross property additions	(1,485,481)
Cost of removal, net of salvage	(34,695)
Allowance for equity funds used during construction	71,263
Other property and investments	(6,514)
NET CASH USED FOR INVESTING ACTIVITIES	(1,455,427)
FINANCING ACTIVITIES	
Increase in notes payable, net	(8,860)
Proceeds -	
Senior notes	675,000
Preferred stock	300,000
Capital contributions from parent company	126,619
Redemptions -	
Senior notes	(300,000)
Trust preferred securities	(300,000)
Capitalized leases	(2,550)
Stock Option Expense	12,399
Payment of preferred stock dividends	(3,370)
Payment of common stock dividends	(678,100)
Other	(13,702)
NET CASH USED FOR FINANCING ACTIVITIES	(192,564)
NET INC (DEC) IN CASH AND TEMPORARY CASH INVESTMENTS	$402
CASH AND TEMPORARY CASH INVESTMENTS AT BEG OF PERIOD	$15,750
CASH AND TEMPORARY CASH INVESTMENTS AT END OF PERIOD	$16,152

2005 *Annual Report*

GEORGIA POWER COMPANY

GEORGIA POWER

A SOUTHERN COMPANY

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Georgia Power Company 2005 Annual Report

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SUMMARY

	2005	2004	Percent Change
Financial Highlights *(in millions):*			
Operating revenues	**$6,634**	$5,371	23.5
Operating expenses	**$5,246**	$4,112	27.6
Net income after dividends on preferred stock	**$715**	$658	8.7
Operating Data:			
Kilowatt-hour sales *(in millions):*			
Retail	**78,982**	77,904	1.4
Sales for resale - non-affiliates	**11,235**	5,970	88.2
Sales for resale - affiliates	**4,855**	4,783	1.5
Total	**95,072**	88,657	7.2
Customers served at year-end *(in thousands)*	**2,115**	2,078	1.8
Peak-hour demand *(in megawatts)*	**15,953**	15,180	5.1
Capitalization Ratios *(percent):*			
Common stock equity	**50.3**	51.0	
Preferred stock	-	0.2	
Long-term debt payable to affiliated trusts	**9.4**	10.1	
Long-term debt	**40.3**	38.7	
Return on Average Common Equity *(percent)*	**14.15**	13.95	
Ratio of Earnings to Fixed Charges *(times)*	**4.92**	5.11	

LETTER TO INVESTORS
Georgia Power 2005 Annual Report

Georgia Power employees' extraordinary response after Hurricane Katrina and other storms hit the Gulf Coast last year is just one of the highlights in what was a remarkable year for the company.

Whether we're responding to storms in our own back yard or to the needs of fellow Southern Company employees and customers, it's extensive pre-planning and excellent execution that makes us so successful – it really is what we do best.

That's why we were honored when the Edison Electric Institute recognized us with its Emergency Assistance Award for the outstanding assistance we provided other utilities recovering last year from hurricanes Katrina, Rita and Wilma.

Our financial results mirror our operational success. With operating revenues of $6.6 billion, Georgia Power's 2005 earnings totaled $715 million, a $57 million, or 8.7 percent, increase from 2004. We earned a 14.15 percent total company return on average common equity during 2005. Georgia Power had net plant in service of $12.0 billion at the end of 2005, with total assets of $17.0 billion.

In 2005, we announced plans to merge one of our sister companies into Georgia Power; we made significant progress on the environmental front; and we overhauled our organizational structure to bring us even closer to our customers.

Late last year, the boards of directors of Southern Company, Savannah Electric and Georgia Power approved a plan to merge Savannah Electric into Georgia Power. This move should result in operational efficiencies and cost savings for Georgia Power.

Savannah Electric customers also are expected to benefit from Georgia Power's more diverse and cost-efficient generating fleet. We anticipate completing the merger by July 2006.

We continued our efforts last year to reduce the environmental impact of our operations by:

- Turning on selective catalytic reduction systems at plants Bowen, Hammond and Wansley. This is expected to reduce the company's emissions of nitrogen oxides and, therefore, its contribution to metro Atlanta's ozone from 15 percent to 6 percent.

- Filing applications for four more scrubbers – two for Plant Wansley and two additional scrubbers for Plant Bowen. Two scrubbers are already under construction at Plant Bowen. Not only will the scrubbers, which remove sulfur dioxide (SO_2) from power plant emissions, reduce SO_2 emissions on each of these generating units by as much as 95 percent, but they also will reduce emissions of fine particulates and mercury. This is important because the Environmental Protection Agency issued its first mercury rule last year requiring significant reductions in mercury emissions from power plants.

- Working closely with DeKalb County in metro Atlanta, which approved the development of a landfill gas generation plant and a 10-year contract to sell the energy to Georgia Power for our voluntary Green Energy program.

In the past 10 years, we have invested $1 billion in environmental controls, and we'll continue to invest in environmental improvement technologies. In fact, over the next five years, Georgia Power's additional environmental investment is expected to total at least $2.4 billion.

In 2005, we also implemented a new organizational structure that moves key company leaders closer to our customers, employees and the communities we serve. We now have officer positions in major cities around the state, including Athens, Augusta, Columbus, Macon, Rome, Valdosta and, following the merger, Savannah.

Our new structure allows us to enhance efficiencies and operate consistently around the state while providing multiple cross-company leadership development opportunities within Southern Company – a key priority as we work to further develop the diversity and strength of our management ranks.

We believe improving diversity in every facet of our business is, simply put, good for business. That's why last year, for example, we launched a Hispanic Resources Web site, a one-stop shop for information to assist Spanish-speaking customers.

After all our hard work, it's nice to be recognized for our success. *Profiles in Diversity Journal* named Georgia Power to its top-10 list of diversity innovation award winners. We also were one of the Fortune 500 companies recognized as the nation's "Best Workplaces for Commuters," in large part because of SmartRide, our company commuter program that has become more popular than ever because of rising fuel prices. *Site Selection* magazine also recognized us as one of the best company's in North America for economic development.

We're especially proud of our linemen, who really shined at the International Lineman's Rodeo last year in Kansas City, winning first place in the overall, overall apprentice, investor-owned utility and senior divisions, along with a handful of individual event awards.

Continued economic vitality in Georgia helped boost electricity sales and was a key contributor to our strong financial results last year. Businesses and individuals were drawn to the state, increasing the number of customers Georgia Power serves to 2.1 million in 2005, a 1.8 percent increase from the previous year. Our retail sales of electricity climbed 1.4 percent in 2005.

It's clear to me that the work our employees do day in and day out and their commitment to the company are what make us successful – they are our greatest asset.

The changes we made and initiatives we launched last year will help ensure that we continue doing what's best for our employees, customers and communities – that we live up to our motto of being a "Citizen Wherever We Serve" – as we work to meet the state's growing demand for energy.

Sincerely,

Michael D. Garrett
April 17, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Georgia Power Company:

We have audited the accompanying balance sheets and statements of capitalization of Georgia Power Company (the "Company") (a wholly owned subsidiary of Southern Company) as of December 31, 2005 and 2004, 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, 2005. 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 the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements (pages 25 to 57) present fairly, in all material respects, the financial position of Georgia Power Company at December 31, 2005 and 2004, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
February 27, 2006

OVERVIEW

Business Activities

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

Many factors affect the opportunities, challenges, and risks of the Company's primary business of selling electricity. These factors include the ability to maintain a stable regulatory environment, to achieve energy sales growth while containing costs, and to recover rising costs. These costs include those related to growing demand, increasingly stringent environmental standards, and fuel prices. In December 2004, the Company completed a major retail rate proceeding that is expected to provide earnings stability (2004 Retail Rate Plan). This regulatory action also enables the recovery of substantial capital investments to facilitate the continued reliability of the transmission and distribution network and continued environmental improvements at the generating plants. Appropriately balancing environmental expenditures with customer prices will continue to challenge the Company for the foreseeable future. The Company expects further rate proceedings in 2006 to address fuel cost recovery due to higher than expected fuel costs for coal and natural gas.

On December 13, 2005, the Company and Savannah Electric and Power Company (Savannah Electric) entered into a merger agreement, under which Savannah Electric will merge into the Company, with the Company continuing as the surviving corporation (the Merger). The Merger must be approved by Savannah Electric's preferred shareholders and is subject to receipt of certain regulatory approvals from the Federal Energy Regulatory Commission (FERC), the Georgia Public Service Commission (PSC), and the Federal Communications Commission. Pending regulatory approvals, the Merger is expected to be completed by July 2006. See FUTURE EARNINGS POTENTIAL – "Merger" and Note 3 to the financial statements under "Retail Regulatory Matters – Merger" for additional information.

Key Performance Indicators

In striving to maximize shareholder value while providing low-cost energy to more than two million customers, the Company continues to focus on several key indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income. The Company's financial success is directly tied to the satisfaction of its customers. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance, expected weather conditions, and expected capital expenditures. Net income is the primary component of the Company's contribution to Southern Company's earnings per share goal.

The Company's 2005 results compared to its targets for some of these indicators are reflected in the following chart.

Key Performance Indicator	2005 Target Performance	**2005 Actual Performance**
Customer Satisfaction	Top quartile in customer surveys	**Top quartile**
Peak Season EFOR	2.75% or less	**1.42%**
Net Income	$678 million	**$715 million**

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The strong financial performance achieved in 2005 reflects the focus that management places on these indicators, as well as the commitment shown by the employees in achieving or exceeding management's expectations.

Earnings

The Company's 2005 earnings totaled $715 million representing a $57 million (8.7 percent) increase over 2004. Operating income increased in 2005 due to higher base retail revenues resulting from the retail rate increase

effective January 1, 2005 and more favorable weather, as well as higher wholesale revenues resulting from new contracts effective January 1, 2005, partially offset by increased non-fuel operating expenses. The Company's 2004 earnings totaled $658 million representing a $27 million (4.3 percent) increase over 2003. Operating income increased in 2004 due to higher base retail revenues attributable to more favorable weather and customer growth during the year, partially offset by higher non-fuel operating expenses. In addition, lower depreciation and amortization expense resulting from a Georgia PSC three-year retail rate plan approved in 2001 (2001 Retail Rate Plan) significantly offset increased purchased power capacity expenses. The Company's 2003 earnings totaled $631 million, representing a $13 million (2.1 percent) increase over 2002 despite lower base retail revenues resulting from the extremely mild summer weather. Higher wholesale revenues and lower non-fuel operating expenses contributed to the 2003 increase.

RESULTS OF OPERATIONS

A condensed income statement for the Company is as follows:

	Amount	Increase (Decrease) From Prior Year		
	2005	**2005**	2004	2003
		(in millions)		
Operating revenues	**$6,634**	**$1,263**	$457	$ 92
Fuel	**1,831**	**598**	128	101
Purchased power	**1,170**	**194**	200	92
Other operation and maintenance	**1,481**	**81**	153	(78)
Depreciation and amortization	**504**	**229**	(74)	(54)
Taxes other than income taxes	**260**	**32**	15	11
Total operating expenses	**5,246**	**1,134**	422	72
Operating income	**1,388**	**129**	35	20
Total other income and (expense)	**(241)**	**(20)**	5	2
Income taxes	**431**	**52**	13	9
Net income	**716**	**57**	27	13
Dividends on preferred stock	**1**	**-**	-	-
Net income after dividends on preferred stock	**$ 715**	**$ 57**	$ 27	$ 13

Revenues

Operating revenues in 2005, 2004, and 2003 and the percent of change from the prior year are as follows:

	Amount		
	2005	2004	2003
		(in millions)	
Retail – prior year	**$4,777**	$4,310	$4,288
Change in -			
Base rates	**195**	-	-
Sales growth	**135**	151	30
Weather	**21**	32	(66)
Fuel cost recovery and other	**515**	284	58
Retail – current year	**$5,643**	4,777	4,310
Sales for resale -			
Non-affiliates	**519**	247	260
Affiliates	**265**	166	175
Total sales for resale	**784**	413	435
Other operating revenues	**207**	181	169
Total operating revenues	**$6,634**	$5,371	$4,914
Percent change	**23.5%**	9.3%	1.9%

Retail base revenues of $3.6 billion in 2005 increased by $351 million (10.9 percent) from 2004 primarily due to the retail rate increase effective January 1, 2005, sustained economic strength, customer growth, more favorable weather, and generally higher prices to large business customers. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information. Retail base revenues of $3.2 billion in 2004 increased by $183 million (6.0 percent) from 2003 primarily due to an improved economy, customer growth, generally higher prices to the Company's large business customers, and more favorable weather. Retail base revenues of $3 billion in 2003 decreased by $36 million (1.2 percent) from 2002 primarily due to extremely mild summer temperatures and the sluggish economy.

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. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information.

Wholesale revenues from sales to non-affiliated utilities were:

	2005	2004	2003
		(in millions)	
Unit power sales --			
Capacity	$ 33	$ 31	$ 34
Energy	31	33	31
Other power sales --			
Capacity and other	155	75	93
Energy	300	108	102
Total	$519	$247	$260

Revenues from unit power sales contracts remained relatively constant in 2005 and 2004. Revenues from unit power sales contracts decreased slightly in 2003 due to decreased energy sales. Revenues from other non-affiliated sales increased $272 million (148.6 percent) in 2005 and decreased $12 million (6.2 percent) and $8 million (3.9 percent) in 2004 and 2003, respectively. The increase in 2005 is due to new contracts with thirty electric membership corporation customers that went into effect in January 2005 which increased the demand for energy. The capacity component of these transactions increased $73.2 million in 2005 over 2004.

Revenues from sales to affiliated companies within the Southern Company electric system, as well as purchases of energy, will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliated sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the FERC. In 2005, kilowatt-hour (KWH) energy sales to affiliates increased 1.5 percent due to higher demand, while the increase in associated revenues was 59.4 percent due to higher fuel prices. In 2004, KWH energy sales to affiliates decreased 18.2 percent due to lower demand. However, the decline in associated revenues was only 4.9 percent due to higher fuel prices. In 2003, KWH energy sales to affiliates increased 47.5 percent due to the combination of increased demand by Southern Power to meet contractual obligations and the availability of power due to milder-than-normal weather in the Company's service territory. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost.

Other operating revenues increased $25.7 million (14.2 percent) in 2005 from 2004 primarily due to higher transmission revenues of $16 million related to work performed for the other owners of the integrated transmission system in the State of Georgia and higher revenues under the open access tariff agreement, higher outdoor lighting revenues of $5.4 million, and higher customer fees that went into effect in January 2005 of $5.9 million. Other operating revenues increased $11.7 million (6.9 percent) in 2004 over 2003 primarily due to higher revenues from outdoor lighting of $4.2 million and pole attachment rentals of $4.9 million and higher gains on sales of emission allowances of $2 million. Other operating revenues increased $4 million (2.4 percent) in 2003 from the prior year primarily due to an increase in the open access transmission tariff rate, which increased revenues $7 million, and higher revenues from increased customer demand for outdoor lighting services of $4 million, partially offset by lower revenues from the rental of electric property of $4 million.

Energy Sales

KWH sales for 2005 and the percent change by year were as follows:

	KWH	Percent Change		
	2005	2005	2004	2003
	(in billions)			
Residential	23.6	2.9%	5.3%	(1.7)%
Commercial	29.8	6.3	4.0	(0.1)
Industrial	25.0	(5.0)	2.5	(0.1)
Other	0.6	(0.1)	1.1	0.4
Total retail	79.0	1.4	3.8	(0.5)
Sales for resale -				
Non-affiliates	11.2	88.2	(32.5)	9.5
Affiliates	4.9	1.5	(18.2)	47.5
Total sales for resale	16.1	49.6	(26.8)	22.0
Total sales	95.1	7.2	(1.2)	2.6

Residential KWH sales increased 2.9 percent in 2005 over 2004 due to more favorable weather, customer growth of 1.7 percent, and a 1.1 percent increase in the average energy consumption per customer. Commercial KWH sales increased 6.3 percent due to more favorable weather, sustained economic strength, customer growth of 1.8 percent, and a reclassification of customers from industrial to commercial to be consistent with the rate structure approved by the Georgia PSC when compared

to 2004. Industrial sales decreased 5.0 percent primarily due to this reclassification of customers.

Residential KWH sales increased 5.3 percent in 2004 from 2003 due to more favorable weather and a 1.9 percent increase in residential customers. Commercial KWH sales increased 4.0 percent in 2004 due to an improved economy and a 2.8 percent increase in commercial customers. Industrial sales increased 2.5 percent in 2004 due to the improved economy.

Residential KWH sales decreased 1.7 percent in 2003 from 2002 due to the effect of the milder summer weather, despite the 2.0 percent increase in residential customers. Commercial KWH sales in 2003 declined slightly due to the milder summer weather, while industrial KWH sales declined slightly due to the sluggish economy. Average retail sales growth assuming normal weather is expected to be 2.1 percent from 2006 to 2010.

Fuel and Purchased Power 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 generating units. The amount and sources of generation, the average cost of fuel per net KWH generated, and the average cost of purchased power per net KWH were as follows:

	2005	2004	2003
Total generation (billions of KWH)	**80.5**	71.5	73.1
Sources of generation (percent) --			
Coal	**75.3**	75.4	75.4
Nuclear	**18.6**	22.5	21.6
Hydro	**2.4**	2.0	2.7
Oil and gas	**3.7**	0.1	0.3
Average cost of fuel per net KWH generated (cents) --	**2.04**	1.55	1.46
Average cost of purchased power per net KWH (cents) --	**7.25**	5.17	4.03

Fuel expense increased 48.5 percent in 2005 from the prior year primarily due to an increase in the average cost of fuel, particularly natural gas, and a 12.3 percent increase in generation to meet higher demand. Fuel expense increased 11.6 percent in 2004 over 2003 primarily due to an increase in the average cost of coal and natural gas. Fuel expense increased 10.1 percent in 2003 over 2002 due to an increase in generation of 3.9 percent because of higher wholesale energy demands and a 2.8 percent higher average cost of fuel due to the higher prices of coal and natural gas in 2003.

Purchased power expense increased $194 million (19.9 percent) in 2005, $200 million (25.9 percent) in 2004, and $92 million (13.3 percent) in 2003. These increases are primarily the result of new purchased power agreements (PPAs) between the Company and Southern Power that went into effect in each of 2004, 2003, and 2002. Additional capacity expenses associated with these PPAs were $30 million, $65 million, and $75 million in 2005, 2004, and 2003, respectively. The increases in purchased power expenses also reflect the impact of the significant increases in fuel costs discussed previously.

A significant upward trend in the cost of coal and natural gas has emerged since 2003, and volatility in these markets is expected to continue. Increased coal prices have been influenced by a worldwide increase in demand as a result of rapid economic growth in China as well as by increases in mining costs. Higher natural gas prices in the United States are the result of increased demand and slightly lower gas supplies despite increased drilling activity. Natural gas supply interruptions, such as those caused by the 2005 and 2004 hurricanes, result in an immediate market response; however, the long-term impact of this price volatility may be reduced by imports of natural gas and liquefied natural gas. Fuel expenses generally do not affect net income, since they are offset by fuel revenues under the Company's fuel cost recovery provisions.

Other Operating Expenses

In 2005, other operations and maintenance expenses increased $81 million (5.8 percent). Maintenance for generating plant and transmission and distribution increased $23.5 million and $13.9 million, respectively, as a result of scheduled outages and, to a lesser extent, certain flexible projects planned for other periods. Increased employee benefit expense of $18.4 million related to pension and medical benefits and higher property insurance costs of $5.3 million resulting from storm damage also contributed to the increase. Customer

assistance expense and uncollectible account expense also increased an additional $9.3 million in 2005 over 2004, primarily as a result of promotional expenses related to an energy efficiency program and an increased number of customer bankruptcies, respectively. In 2004, other operations and maintenance expenses increased $153 million (12.3 percent) due to the timing of generating plant maintenance of $39 million and transmission and distribution maintenance of $39 million. Increased employee benefit expense of $30 million related to pension and medical benefits and higher workers compensation expense of $8 million also contributed to the increase. In 2003, other operations and maintenance expenses decreased $78 million (5.9 percent) due to the timing of generating plant maintenance of $46 million and transmission and distribution maintenance of $8 million and lower severance costs of $8 million.

Depreciation and amortization increased $229 million (83 percent) in 2005 over 2004 primarily due to the expiration at the end of 2004 of certain provisions of the Company's 2001 Retail Rate Plan. In accordance with the 2001 Retail Rate Plan, the Company amortized an accelerated cost recovery liability as a credit to amortization expense and recognized new Georgia PSC-certified purchased power costs in rates evenly over the three years ended December 31, 2004. This treatment resulted in a credit to amortization expense of $187.1 million in 2004 and a total decrease in depreciation and amortization of $74 million and $54 million in 2004 and 2003, respectively. See Note 3 to the financial statements under "Retail Regulatory Matters -- Rate Plans" for additional information.

Taxes other than income taxes increased $32 million (14.1 percent) primarily due to higher municipal gross receipts taxes of $18.1 million resulting from increased operating revenues and higher property taxes of $14.0 million. Taxes other than income taxes increased $15 million (7.0 percent) in 2004 due to higher municipal gross receipts taxes associated with increased operating revenues. Taxes other than income taxes increased $11 million (5.4 percent) in 2003 due mainly to a favorable true-up of state property tax valuations in 2002.

Other Income and (Expense)

Allowance for equity funds used during construction remained relatively constant in 2005 and increased $15.9 million in 2004, primarily due to the construction of the McIntosh combined cycle Units 10 and 11 which were placed in service in June 2005.

Interest income remained relatively constant in 2005. Interest income decreased $9 million in 2004 and increased $12 million in 2003 when compared to the prior year primarily due to interest on a favorable income tax settlement of $14.5 million in 2003.

Interest expense increased $38.8 million (21.3 percent) in 2005 from 2004 primarily due to the issuance of additional senior notes in 2005 and generally higher interest rates on variable rate debt and commercial paper. Interest expense remained relatively constant in 2004. Interest expense increased in 2003 primarily due to an increase in senior notes outstanding that was partially offset by a reduction in short-term debt outstanding. The Company refinanced or retired $635 million, $400 million, and $665 million of securities in 2005, 2004, and 2003, respectively. Interest capitalized increased in 2005 and 2004 due to the Plant McIntosh construction referenced above and decreased in 2003 due to the transfer of a project to Southern Power in 2002.

Other income and (expense), net increased $17.1 million in 2005 from 2004 primarily due to $14.2 million of additional gas hedge gains. Other income and (expense), net decreased in 2004 primarily due to the $13 million disallowance of Plant McIntosh construction costs in December 2004, partially offset by a $7.5 million decrease in donations and $3.4 million in increased income from a customer pricing program. See Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Hedging Program" and "Plant McIntosh Construction Project" for additional information.

Effects of Inflation

The Company is subject to rate regulation that is based on the recovery of historical costs. In addition, the income tax laws are based on historical costs. Therefore, inflation creates an economic loss because the Company is recovering its costs of investments in dollars that have less purchasing power. While the inflation rate has been relatively low in recent years, it continues to have an adverse effect on the Company because of the large investment in utility plant with long economic lives. Conventional accounting for historical cost does not recognize this economic loss nor the partially offsetting gain that arises through financing facilities with fixed-

money obligations such as long-term debt, preferred stock, and preferred securities. Any recognition of inflation by regulatory authorities is reflected in the rate of return allowed in the Company's approved electric rates.

FUTURE EARNINGS POTENTIAL

General

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

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability of the Company to maintain a stable regulatory environment that continues to allow for the recovery of all prudently incurred costs. Future earnings in the near term will depend, in part, upon growth in energy sales, which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth in the Company's service area.

Environmental Matters

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S District Court for the Northern District of Georgia against the Company and Alabama Power, alleging that the Company and Alabama Power had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws with respect to certain coal-fired generating facilities. Through subsequent amendments and other legal proceedings, the EPA added Savannah Electric as a defendant to the original action and filed a separate action against Alabama Power after it was dismissed from the original action. In these lawsuits, the EPA alleges that NSR violations occurred at eight coal-fired generating facilities, including the Company's Plants Bowen and Scherer. The civil action requests penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. On June 3, 2005, the U.S. District for the Northern District of Alabama issued a decision in favor of Alabama Power on two primary legal issues in the case; however, the decision does not resolve the case, nor does it address other legal issues associated with the EPA's allegations. In accordance with a separate court order, Alabama Power and the EPA are currently participating in mediation with respect to the EPA's claims. The action against the Company and Savannah Electric has been administratively closed since the spring of 2001, and none of the parties has sought to reopen the case. See Note 3 to the financial statements under "Environmental Matters - New Source Review Actions."

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $32,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in this matter could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

In December 2002 and October 2003, the EPA issued final revisions to its NSR regulations under the Clean Air Act. A coalition of states and environmental organizations filed petitions for review of these regulations. On June 24, 2005, the U.S. Court of Appeals for the District of Columbia Circuit upheld, in part, the EPA's December 2002 revisions to its NSR regulations, which included changes to the regulatory exclusions and

methods of calculating emissions increases. However, the court vacated portions of those revisions, including those addressing the exclusion of certain pollution control projects. The October 2003 revisions, which clarified the scope of the existing Routine Maintenance, Repair and Replacement exclusion, have been stayed by the Court of Appeals pending its review of the rules. On October 20, 2005, the EPA also published a proposed rule clarifying the test for determining when an emissions increase subject to the NSR requirements has occurred. The impact of these revisions and proposed rules will depend on adoption of the final rules by the EPA and the State of Georgia's implementation of such rules, as well as the outcome of any additional legal challenges, and, therefore, cannot be determined at this time.

Carbon Dioxide Litigation

In July 2004, attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed a complaint in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. A nearly identical complaint was filed by three environmental groups in the same court. The complaints allege that the companies' emissions of carbon dioxide, a greenhouse gas, contribute to global warming, which the plaintiffs assert is a public nuisance. Under common law public and private nuisance theories, the plaintiffs seek a judicial order (1) holding each defendant jointly and severally liable for creating, contributing to, and/or maintaining global warming and (2) requiring each of the defendants to cap its emissions of carbon dioxide and then reduce those emissions by a specified percentage each year for at least a decade. Plaintiffs have not, however, requested that damages be awarded in connection with their claims. Southern Company believes these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2005, the U.S. District Court for the Southern District of New York granted Southern Company's and the other defendants' motions to dismiss these cases. The plaintiffs filed an appeal to the U.S. Court of Appeals for the Second Circuit on October 19, 2005. The ultimate outcome of these matters cannot be determined at this time.

Plant Wansley Environmental Litigation

In December 2002, the Sierra Club, Physicians for Social Responsibility, Georgia Forestwatch, and one individual filed a civil suit in the U.S. District Court for the Northern District of Georgia against the Company for alleged violations of the Clean Air Act at four of the units at Plant Wansley. 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. The liability phase of the case has concluded with the court ruling in favor of the Company in part and the plaintiffs in part. In March 2005, the U.S. Court of Appeals for the Eleventh Circuit accepted the Company's petition for review of the district court's order, and oral arguments were held on January 24, 2006. The district court case has been administratively closed pending that appeal. If necessary, the district court will hold a separate trial which will address civil penalties and possible injunctive relief requested by the plaintiffs. The ultimate outcome of this matter cannot currently be determined; however, an adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require the payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

Environmental Statutes and Regulations

General

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. Applicable statutes 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 these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2005, the Company had invested approximately $1.2 billion in

capital projects to comply with these requirements, with annual costs of $117.4 million, $47.4 million, and $105.7 million for 2005, 2004, and 2003, respectively. Over the next decade, the Company expects that capital expenditures could exceed an additional $3.3 billion to assure compliance with existing and new regulations, including $410 million, $674.6 million, and $515.8 million for 2006, 2007, and 2008, respectively. Because the Company's compliance strategy is impacted by changes to existing environmental laws and regulations, the cost, availability, and existing inventory of emission allowances, and the Company's fuel mix, the ultimate outcome cannot be determined at this time. Environmental costs that are known and estimable at this time are included in capital expenditures discussed under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein.

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

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Through 2005, the Company had spent approximately $787.9 million in reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions and in monitoring emissions pursuant to the Clean Air Act. Additional controls have been announced and are currently being installed at several plants to further reduce SO_2 and NO_x emissions, maintain compliance with existing regulations, and to meet new requirements.

Approximately $699.8 million of these expenditures are related to reducing NO_x emissions pursuant to state and federal requirements in connection with the EPA's one-hour ozone standard and the 1998 regional NO_x reduction rules. Although the State of Georgia was originally included in the states subject to the regional NO_x rules, the EPA, in August 2005, stayed compliance with these requirements and initiated rulemakings to address issues raised in a petition for reconsideration filed by a coalition of Georgia industries. The impact of the 1998 regional NO_x reduction rules for Georgia will depend on the outcome of the petition for reconsideration and/or any subsequent development and approval of the State of Georgia's state implementation plan.

In 2005, the EPA revoked the one-hour ozone standard and published the final set of rules for implementation of the new, more stringent eight-hour ozone standard. Areas within the Company's service area that have been designated as nonattainment under the eight-hour ozone standard include Macon (Georgia) and a 20-county area within metropolitan Atlanta. State implementation plans, including new emission control regulations necessary to bring those areas into attainment are required for most areas by June 2007. These state implementation plans could require further reductions in NO_x emissions from power plants.

During 2005, the EPA's fine particulate matter "nonattainment" designations became effective for several areas within the Company's service area in Georgia, and the EPA proposed a rule for the implementation of the fine particulate matter standard. The EPA plans to finalize the proposed implementation rule in 2006. State plans for addressing the nonattainment designations are required by April 2008 and could require further reductions in SO_2 and NO_x emissions from power plants. The EPA has also published proposed revisions to lower the level of particulate matter currently allowed.

The EPA issued the final Clean Air Interstate Rule on March 10, 2005. This cap-and-trade rule addresses power plant SO_2 and NO_x emissions that were found to contribute to nonattainment of the eight-hour ozone and fine particulate matter standards in downwind states. Twenty-eight eastern states, including the State of Georgia, are subject to the requirements of the rule. The rule calls for additional reductions of NO_x and/or SO_2 to be achieved in two phases, 2009/2010 and 2015. These reductions will be accomplished by the installation of additional emission controls at the Company's coal-fired facilities or by the purchase of emission allowances from a cap-and-trade program.

The Clean Air Visibility Rule (formerly called the Regional Haze Rule) was finalized on July 6, 2005. The goal of this rule is to restore natural visibility conditions in certain areas (primarily national parks

and wilderness areas) by 2064. The rule involves the application of Best Available Retrofit Technology (BART) requirements and a review each decade, beginning in 2018, of progress toward the goal. BART requires that sources that contribute to visibility impairment implement additional emission reductions, if necessary, to make progress toward remedying current visibility concerns. For power plants, the Clean Air Visibility Rule allows states to determine that the Clean Air Interstate Rule satisfies BART requirements for SO_2 and NO_x. However, additional requirements could be imposed. By December 17, 2007, states must submit implementation plans that contain emission reduction strategies for implementing BART requirements and for achieving sufficient and reasonable progress toward the goal.

On March 15, 2005, the EPA announced the final Clean Air Mercury Rule, a cap-and-trade program for the reduction of mercury emissions from coal-fired power plants. The rule sets caps on mercury emissions to be implemented in two phases, 2010 and 2018, and provides for an emission allowance trading market. The Company anticipates that emission controls installed to achieve compliance with the Clean Air Interstate Rule and the eight-hour ozone and fine-particulate standards will also result in mercury emission reductions. However, the long-term capability of emission control equipment to reduce mercury emissions is still being evaluated, and the installation of additional control technologies may be required.

The impacts of the eight-hour ozone standard, the fine particulate matter nonattainment designations, the Clean Air Interstate Rule, the Clean Air Visibility Rule, and the Clear Air Mercury Rule on the Company, will depend on the development and implementation of rules at the state level. States implementing the Clean Air Mercury Rule and the Clear Air Interstate Rule, in particular, have the option not to participate in the national cap-and-trade programs and could require reductions greater than those mandated by the federal rules. Such impacts will also depend on resolution of pending legal challenges to the Clean Air Interstate Rule, the Clean Air Mercury Rule and a related petition from the State of North Carolina under section 126 of the Clean Air Act, also related to the interstate transport of air pollutants. Therefore, the full impacts of these regulations on the Company cannot be determined at this time. The Company has developed and continually updates a comprehensive environmental compliance strategy to comply with the continuing and new environmental requirements discussed above. As part of this strategy, the Company plans to install additional SO_2, NO_x, and mercury emission controls within the next several years to assure continued compliance with applicable air quality requirements.

Water Quality

In July 2004, the EPA published final rules under the Clean Water Act for the purpose of reducing impingement and entrainment of fish and fish larvae at power plants' cooling water intake structures. The new rules require baseline biological information and, perhaps, installation of fish protection technology near some intake structures at existing power plants.

The Company is installing cooling towers at additional facilities under the Clean Water Act to cool water prior to discharge. Near Atlanta, a cooling tower for one plant was completed in 2004 and two others are scheduled for completion in 2008. The total estimated cost of these projects is $173 million, with $85 million remaining to be spent. The Company is also conducting a study of the aquatic environment at another facility to determine if further thermal controls are necessary at that plant.

The full impact of these new rules will depend on the results of studies and analyses performed as part of the rules' implementation and the actual requirements established by the State of Georgia, and therefore, cannot be determined at this time

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and release 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 and monitor known sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Remediation" for additional information.

Under Georgia PSC ratemaking provisions, $22 million has been deferred in a regulatory liability account related to certain environmental insurance settlements. Under the 2004 Retail Rate Plan, this regulatory liability is being amortized as a credit to expense over a three-year period that began January 1, 2005. However, the Georgia PSC also approved an annual environmental accrual of $5.4 million. Environmental remediation expenditures are being charged against the resulting reserve as they are incurred. The annual accrual amount will be reviewed and adjusted in future regulatory proceedings.

Global Climate Issues

Domestic efforts to limit greenhouse gas emissions have been spurred by international discussions surrounding the Framework Convention on Climate Change, and specifically the Kyoto Protocol -- which proposes constraints on the emissions of greenhouse gases for a group of industrialized countries. The Bush Administration has not supported U.S. ratification of the Kyoto Protocol or other mandatory carbon dioxide reduction legislation; however, in 2002, it did announce a goal to reduce the greenhouse gas intensity of the U.S. – the ratio of greenhouse gas emissions to the value of U.S. economic output -- by 18 percent by 2012. A year later, the Department of Energy (DOE) announced the Climate VISION program to support this goal. Energy-intensive industries, including electricity generation, are the initial focus of this program. Southern Company is involved in the development of a voluntary electric utility sector climate change initiative in partnership with the government. In a memorandum of understanding signed in December 2004 with the DOE under Climate VISION, the utility sector pledged to reduce its greenhouse gas emissions rate by 3 percent to 5 percent by 2010-2012. The Company is continuing to evaluate future energy and emissions profiles relative to the Climate VISION program and is analyzing voluntary programs to support the industry initiative.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates at market-based prices. The Company also has FERC authority to make short-term opportunity sales at market rates. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in that proceeding. In February 2005, Southern Company submitted responsive information. In February 2006, the FERC suspended the proceeding. Any new market-based rate transactions in its retail service territory entered into after February 27, 2005 are subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. The impact of such sales through December 31, 2005 is not expected to exceed $4.9 million. The refund period covers 15 months. In the event that the FERC's default mitigation measures for entities that are found to have market power are ultimately applied, the Company may be required to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates. The final outcome of this matter will depend on the form in which the final methodology for assessing generation market power and mitigation rules may be ultimately adopted and cannot be determined at this time.

In addition, in May 2005, the FERC started an investigation to determine whether Southern Company satisfies the other three parts of the FERC's market-based rate analysis: transmission market power, barriers to entry, and affiliate abuse or reciprocal dealing. The FERC established a new refund period related to this expanded investigation. Any and all new market-based rate transactions both inside and outside Southern Company's retail service territory involving any Southern Company subsidiary, including the Company, will be subject to refund to the extent the FERC orders lower rates as a result of this new investigation, with the 15-month refund period beginning July 19, 2005. The impact of such sales through December 31, 2005 is not expected to exceed $10.9 million, of which $3.2 million relates to sales inside the retail service territory as discussed above. The FERC also directed that this expanded proceeding be held in abeyance pending the outcome of the proceeding on the IIC discussed below.

The Company believes that there is no meritorious basis for this proceeding and is vigorously defending itself in this matter. However, the final outcome of this

matter, including any remedies to be applied in the event of an adverse ruling in this proceeding, cannot now be determined.

Intercompany Interchange Contract

The Company's generation fleet in its retail service territory is operated under the IIC, as approved by the FERC. In May 2005, the FERC also initiated a new proceeding to examine (1) the provisions of the IIC among Alabama Power, the Company, Gulf Power, Mississippi Power, Savannah Electric, Southern Power, and Southern Company Services, Inc., as agent, under the terms of which the power pool of Southern Company is operated, and, in particular, the propriety of the continued inclusion of Southern Power as a party to the IIC, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining Southern Power as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of Southern Power, the FERC authorized Southern Power's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct. The FERC order directs that the administrative law judge who presided over the McIntosh PPA proceeding discussed herein under "PSC Matters – Plant McIntosh Construction Project", be assigned to preside over the hearing in this proceeding and that the testimony and exhibits presented in that proceeding be preserved to the extent appropriate. Hearings are scheduled for September 2006. Effective July 19, 2005, revenues from transactions under the IIC involving any Southern Company subsidiaries, including the Company, are subject to refund to the extent the FERC orders any changes to the IIC.

The Company believes that there is no meritorious basis for this proceeding and is vigorously defending itself in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in this proceeding, cannot now be determined.

Generation Interconnection Agreements

In July 2003, the FERC issued its final rule on the standardization of generation interconnection agreements and procedures (Order 2003). Order 2003 shifts much of the financial burden of new transmission investment from the generator to the transmission provider. The FERC has indicated that Order 2003, which was effective January 20, 2004, is to be applied prospectively to interconnection agreements. Subsidiaries of Tenaska, Inc., as counterparties to three previously executed interconnection agreements with subsidiaries of Southern Company, including the Company, have filed complaints at the FERC requesting that the FERC modify the agreements and that the Company refund a total of $7.9 million previously paid for interconnection facilities, with interest. The Company has opposed all such requests, and the proceedings are still pending. The impact of Order 2003 and its subsequent rehearings on the Company and the final results of these matters cannot be determined at this time.

Transmission

In December 1999, the FERC issued its final rule on Regional Transmission Organizations (RTOs). Since that time, there have been a number of additional proceedings at the FERC designed to encourage further voluntary formation of RTOs or to mandate their formation. However, at the current time, there are no active proceedings that would require the Company to participate in an RTO. Current FERC efforts that may potentially change the regulatory and/or operational structure of transmission include rules related to the standardization of generation interconnection, as well as an inquiry into, among other things, market power by vertically integrated utilities. See "Generation Interconnection Agreements" and "Market-Based Rate Authority" herein for additional information. The final outcome of these proceedings cannot now be determined. However, the Company's financial condition, results of operations, and cash flows could be adversely affected by future changes in the federal regulatory or operational structure of transmission.

PSC Matters

Merger

In connection with the Merger, the Company and Savannah Electric plan to establish a coastal regional organization for the Company that will be operating following completion of the Merger. Management expects that current Savannah Electric employees will fill most of the positions in the new regional organization.

While the Georgia PSC does not have specific approval authority over the merger of electric utilities, in January 2006, the Company and Savannah Electric filed an application with the Georgia PSC for certain approvals necessary to complete the Merger. In particular, the Company and Savannah Electric are seeking the approval of the Georgia PSC with respect to the following matters:

- the transfer of Savannah Electric's generating facilities and certification of the generating facilities as the Company's assets;
- amendments to the Company's Integrated Resource Plan to add the current Savannah Electric's customers and generating facilities;
- the transfer of Savannah Electric's assigned service territory to the Company;
- adoption of the Company's service rules and regulations to the current Savannah Electric customers;
- new fuel rate and base rate schedules that would apply to the Company's sale of electricity to the current Savannah Electric customers;
- adoption of a "merger transition adjustment" rate that would be used to more closely align Savannah Electric's existing base rates to those of the Company and a "merger transition credit" rate that would credit the additional revenues collected from former Savannah Electric customers to the Company's existing customers; and
- the issuance of additional shares of the Company's common stock to Southern Company in exchange for Southern Company's shares of Savannah Electric common stock.

The Company has also requested the Georgia PSC to better align the rates for Savannah Electric's customers with those of the Company. Currently, Savannah Electric customers pay slightly lower base rates and significantly higher fuel rates than the Company's customers. The overall effect is that Savannah Electric customers pay substantially higher overall costs for electricity. See "Fuel Cost Recovery" herein for additional information.

Rate Plans

In December 2004, the Georgia PSC approved the 2004 Retail Rate Plan for the three-year period ending December 31, 2007. Under the terms of the 2004 Retail Rate Plan, earnings are being evaluated annually against a retail return on common equity (ROE) range of 10.25 percent to 12.25 percent. Two-thirds of any earnings above 12.25 percent will be applied to rate refunds, with the remaining one-third retained by the Company. Retail rates were increased by approximately $194 million and customer fees were increased by approximately $9 million effective January 1, 2005 to cover the higher costs of purchased power; operation and maintenance expenses; environmental compliance; and continued investment in new generation, transmission and distribution facilities to support growth and ensure reliability. In 2005 the Company recorded $2.7 million revenue subject to refund for estimated earnings above 12.25 percent retail ROE.

The Company is required to file a general rate case by July 1, 2007, in response to which the Georgia PSC would be expected to determine whether the 2004 Retail Rate Plan should be continued, modified, or discontinued. Until then, the Company will not file for a general base rate increase unless its projected retail ROE falls below 10.25 percent. However, in connection with the Merger, the Company has requested Georgia PSC approval of a "merger transition adjustment" that would be used to adjust Savannah Electric's existing base rates to more closely match the existing base rates for the Company. See Note 3 to the financial statements under "Retail Regulatory Matters - Rate Plans" for additional information.

Plant McIntosh Construction Project

In December 2002 after a competitive bidding process, the Georgia PSC certified PPAs between Southern Power and the Company and Savannah Electric for capacity from Plant McIntosh Units 10 and 11, construction of which was completed in June 2005. In April 2003, Southern Power applied for FERC approval of these PPAs. In July 2003, the FERC accepted the PPAs to become effective June 1, 2005, subject to refund, and ordered that hearings be held. Intervenors opposed the FERC's acceptance of the PPAs, alleging that they did not meet the applicable standards for market-based rates between affiliates. To ensure the timely completion of the Plant McIntosh construction project and the availability of the units in the summer of 2005 for their retail customers, in May 2004, the Company and Savannah Electric requested the Georgia PSC to direct them to acquire the Plant McIntosh construction project. The Georgia PSC issued such an order and the transfer occurred on May 24, 2004 at a total cost of approximately $415 million, including

$14 million of transmission interconnection facilities. Subsequently, Southern Power filed a request to withdraw the PPAs and to terminate the ongoing FERC proceedings. In August 2004, the FERC issued a notice accepting the request to withdraw the PPAs and permitting such request to become effective by operation of law. However, the FERC made no determination on what additional steps may need to be taken with respect to testimony provided in the proceedings. See "FERC Matters - Intercompany Interchange Contract" above for additional information.

In connection with the 2004 Retail Rate Plan, the Georgia PSC approved the transfer of the Plant McIntosh construction project at a total fair market value of approximately $385 million. This value reflected an approximate $16 million disallowance, of which $13 million was attributable to the Company, and reduced the Company's 2004 net income by approximately $8 million. The Georgia PSC also certified a total completion cost of $547 million for the project. In June 2005, Plant McIntosh Units 10 and 11 were placed in service at a total cost that did not exceed the certified amount. Under the 2004 Retail Rate Plan, the Plant McIntosh revenue requirements impact will be reflected in the Company's rates evenly over the three years ending 2007. See Note 3 to the financial statements under "Retail Regulatory Matters -- Rate Plans" and "Plant McIntosh Construction Project" for additional information.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. In recent months, the Company has experienced higher than expected fuel costs for coal and natural gas. Those higher fuel costs have increased the under recovered fuel costs included in the balance sheets herein.

In May 2005, the Georgia PSC approved the Company's request to increase customer fuel rates by approximately 9.5 percent to recover under recovered fuel costs of approximately $508 million existing as of May 31, 2005 over a four-year period that began June 1, 2005. Under recovered fuel amounts for the period subsequent to June 1, 2005 totaled $327.5 million through December 31, 2005. The Georgia PSC's order instructed that such amounts be reviewed semi-annually beginning February 2006. If the amount under or over recovered exceeds $50 million at the evaluation date, the Company would be required to file for a temporary fuel rate change. In addition, Savannah Electric's under recovered fuel costs totaled $77.7 million at December 31, 2005. In accordance with the Georgia PSC order, Savannah Electric was scheduled to file an additional request for a fuel cost recovery increase in January 2006. The Company has agreed with a Georgia PSC staff recommendation to forego the temporary fuel rate process, and Savannah Electric has postponed its scheduled filing. Instead, the Company and Savannah Electric will file a combined request in March 2006 to increase the Company's fuel cost recovery rate.

The case will seek approval of a fuel cost recovery rate based upon future fuel cost projections for the combined Company and Savannah Electric generating fleet as well as the under recovered fuel balances existing at June 30, 2006. The new fuel cost recovery rate would be billed beginning in July 2006 to all of the Company's customers, including the existing Savannah Electric customers. Under recovered amounts as of the date of the Merger will be paid by the appropriate customer groups.

In August 2005, the Georgia PSC initiated an investigation of Savannah Electric's fuel practices. In February 2006, an investigation of the Company's fuel practices was initiated. The Company and Savannah Electric are responding to data requests and cooperating in the investigations. The final outcome of this matter cannot now be determined.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable cost and amounts billed in current regulated rates. Accordingly, any increase in the billing factor would have no significant effect on the Company's revenues or net income, but would increase annual cash flow.

Nuclear

As part of a potential expansion of Plant Vogtle, the Company and Southern Nuclear have notified the Nuclear Regulatory Commission (NRC) of their intent to apply for an early site permit (ESP) this year and a combined construction and operating license (COL) in 2008. In addition, a reactor design from Westinghouse Electric Company has been selected and a purchase agreement is being negotiated. Participation agreements have been reached with each of the existing Plant Vogtle co-owners. See Note 4 to the financial statements for additional information on

these co-owners. At this point, no final decision has been made regarding actual construction. The NRC's streamlined licensing process for new nuclear units allows utilities to seek regulatory approval at various stages. These stages include design certification, which is obtained by the reactor vendor, and the ESP and COL, which are each obtained by the owner-operators of the units. An ESP indicates site approval is obtained before a company decides to build and the COL provides regulatory approval for building and operating the plant. In addition, any generation by the Company must be certified by the Georgia PSC.

Southern Company also is participating in NuStart Energy Development, LLC (NuStart Energy), a broad-based nuclear industry consortium formed to share the cost of developing a COL and the related NRC review. NuStart Energy plans to complete detailed engineering design work and to prepare COL applications for two advanced reactor designs, then to choose one of the applications and file it for NRC review and approval. The COL ultimately is expected to be transferred to one or more of the consortium companies; however, at this time, none of them have committed to build a new nuclear plant.

Other Matters

In accordance with Financial Accounting Standards Board (FASB) Statement No. 87, Employers' Accounting for Pensions, the Company recorded non-cash pension income, before tax, of approximately $21 million, $35 million, and $54 million in 2005, 2004, and 2003, respectively. Postretirement benefit costs for the Company were $47 million, $44 million, and $41 million in 2005, 2004, and 2003, respectively. Both pension and postretirement costs are expected to trend upward. Such amounts are dependent on several factors including trust earnings and changes to the plans. A portion of pension income and postretirement benefit costs is capitalized based on construction-related labor charges. For the Company, pension income or expense and postretirement benefit costs are a component of the regulated rates and generally do not have a long-term effect on net income. For more information regarding pension and postretirement benefits, see Note 2 to the financial statements.

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

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

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

Electric Utility Regulation

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

As reflected in Note 1 to the financial statements under "Regulatory Assets and Liabilities," significant regulatory assets and liabilities have been recorded.

Management reviews the ultimate recoverability of these regulatory assets and liabilities based on applicable regulatory guidelines and accounting principles generally accepted in the United States. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

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

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

Unbilled Revenues

Revenues related to the sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated. Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, power delivery volume, and other operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.

New Accounting Standards

Income Taxes

In December 2004, the FASB issued FASB Staff Position 109-1, Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004 (FSP 109-1), which requires that the generation deduction be accounted for as a special tax deduction rather than as a tax rate reduction. The Company adopted FSP 109-1 in the first quarter of 2005 with no material impact on its financial statements.

Conditional Asset Retirement Obligations

Effective December 31, 2005, the Company adopted the provision of FASB Interpretation No. 47, Conditional Asset Retirement Obligations (FIN 47), which requires that an asset retirement obligation be recorded even though the timing and/or method of settlement are conditional on future events. Prior to December 2005, the Company did not recognize asset retirement obligations for asbestos removal because the timing of retirements was dependent on future events. For additional information, see Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal."

At December 31, 2005, the Company recorded additional asset retirement obligations (and assets) of approximately $91 million. The adoption of FIN 47 did not have any effect on the Company's income statement.

Stock Options

On January 1, 2006, the Company adopted FASB Statement No. 123R, Share-Based Payment, on a modified prospective basis. This statement requires that compensation cost relating to share-based payment transactions be recognized in financial statements. That cost will be measured based on the grant date fair value of the equity or liability instruments issued. Although the compensation expense required under the revised statement differs slightly, the impacts on the Company's financial statements are similar to the pro forma disclosures included in Note 1 to the financial statements under "Stock Options."

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition continued to be stable at December 31, 2005 with emphasis on cost control measures combined with significantly lower costs of capital, achieved through the refinancing and/or redemption of higher-cost securities. Cash flow from operations increased $56 million resulting primarily from increased retail operating revenues (see RESULTS OF OPERATIONS herein), partially offset by the increase in under recovered deferred fuel costs.

Fuel costs are generally recoverable in future periods and are reflected on the balance sheets as under recovered regulatory clause revenues. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information.

In 2005, gross utility plant additions were $906 million. These additions were primarily related to Plant McIntosh Units 10 and 11, transmission and distribution facilities, nuclear fuel, and equipment to comply with environmental standards. The majority of funds needed for gross property additions for the last several years have been provided from operating activities and capital contributions from Southern Company. The statements of cash flows provide additional details.

The Company's ratio of common equity to total capitalization -- including short-term debt -- was 48.3 percent in 2005, 47.7 percent in 2004, and 48.3 percent in 2003. The Company has received investment grade ratings from the major rating agencies.

Sources of Capital

The Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows. However, the type and timing of any future financings, if needed, will depend on market conditions, regulatory approval, and other factors.

The issuance of long-term securities by the Company is subject to the approval of the Georgia PSC. In addition, the issuance of short-term debt securities by the Company is subject to regulatory approval by the FERC following the repeal of the Public Utility Holding Company Act of 1935, as amended, on February 8, 2006. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the appropriate regulatory authorities, as well as the amounts registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company.

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

To meet short-term cash needs and contingencies, the Company had credit arrangements with banks totaling $780 million, of which $778 million was unused, at the beginning of 2006. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper and extendible commercial notes at the request and for the benefit of the Company and the other retail operating companies.

Proceeds from such issuances for the benefit of the Company are loaned directly to the Company and are not commingled with proceeds from issuances for the benefits of any other operating company. The obligations of each company under these arrangements are several; there is no cross affiliate credit support. As of December 31, 2005, the Company had outstanding $268 million of commercial paper and no extendible commercial notes.

At the beginning of 2006, bank credit arrangements were as follows:

		Expires		
Total	Unused	2006	2007	2010
		(in millions)		
$780	$778	$70	$350	$360

The credit arrangements that expire in 2006 allow for the execution of term loans for an additional two-year period.

Financing Activities

During 2005, the Company issued $810 million of long-term debt. The issuances were used to refund $635 million of long-term debt and to fund the Company's ongoing construction program.

Subsequent to December 31, 2005, the Company redeemed all of its outstanding preferred stock at a redemption price of $107 per share.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- or Baa3 or below. Generally, collateral may be provided for by a Southern Company guaranty, letter of credit, or cash. These contracts are primarily for physical electricity purchases and sales. At December 31, 2005, the maximum potential collateral requirements at a BBB- or Baa3 rating were approximately $6 million. The maximum potential collateral requirements at a rating below BBB- or Baa3 were approximately $245 million.

The Company is also party to certain derivative agreements that could require collateral and/or accelerated payment in the event of a credit rating change to below investment grade. These agreements are primarily for natural gas price risk management activities. At December 31, 2005, the Company had no material exposure related to these agreements.

Market Price Risk

Due to cost-based rate regulation, the Company has limited exposure to market rate 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 and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress tests, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company has entered into forward starting interest rate swaps that have been designated as hedges. These swaps have a notional amount of $300 million and are related to anticipated debt issuances over the next two years. The weighted average interest rate on outstanding variable long-term debt that has not been hedged at January 1, 2006 was 3.56 percent. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $3.3 million at January 1, 2006. For further information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

To mitigate residual risks relative to movements in electricity prices, the Company enters into fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, into similar contracts for gas purchases.

The Company has implemented a fuel hedging program at the instruction of the Georgia PSC. Fair

value of changes in energy-related derivative contracts and year-end valuations were as follows at December 31:

	Changes in Fair Value	
	2005	2004
	(in millions)	
Contracts beginning of year	**$5.8**	$ 3.2
Contracts realized or settled	**(40.0)**	(12.2)
Current period changes (a)	**60.8**	14.8
Contracts end of year	**$26.6**	$ 5.8

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

	Source of 2005 Year-End Valuation Prices		
	Total	Maturity	
	Fair Value	Year 1	1-3 Years
		(in millions)	
Actively quoted	**$26.8**	$16.4	$10.4
External sources	**(0.2)**	(0.2)	-
Contracts end of year	**$26.6**	$16.2	$10.4

Unrealized gains and losses from mark to market adjustments on derivative contracts related to the Company's fuel hedging programs are recorded as regulatory assets and liabilities. Realized gains and losses from these programs are included in fuel expense and are recovered through the Company's fuel cost recovery mechanism. Of the net gains, the Company is allowed to retain 25 percent in earnings. In 2005, the Company had a total net gain of $64.1 million, of which the Company retained $16.0 million. See Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Hedging Program" for additional information. Gains and losses on derivative contracts that are not designated as hedges are recognized in the statements of income as incurred. At December 31, 2005, the fair value of derivative energy contracts was reflected in the financial statements as follows:

	Amounts
	(in millions)
Regulatory liabilities, net	$26.7
Net income	(0.1)
Total fair value	$26.6

Unrealized gains (losses) recognized in income in 2005, 2004, and 2003 were not material. The Company is exposed to market price risk in the event of nonperformance by counterparties to the derivative energy contracts. The Company's policy is to enter into agreements with counterparties that have investment grade credit ratings by Moody's and Standard & Poor's or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to be $1.3 billion for 2006, $1.4 billion for 2007, and $1.3 billion for 2008. Environmental expenditures included in these amounts are $410 million, $674.6 million, and $515.8 million for 2006, 2007, and 2008, respectively. Actual construction costs may vary from this estimate because of changes in such factors as: business conditions; environmental regulations; nuclear plant regulations; FERC rules and transmission regulations; load projections; the cost and efficiency of construction labor, equipment, and materials; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

As a result of requirements by the NRC, the Company has established external trust funds for nuclear decommissioning costs. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning." Also as discussed in Note 1 to the financial statements under "Nuclear Fuel Disposal Costs," in 1993 the DOE implemented a special assessment over a 15-year period on utilities with nuclear plants to be used for the decontamination and decommissioning of its nuclear fuel enrichment facilities.

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the Georgia PSC and the FERC.

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

Amounts in the following chart exclude any effects on the Company of the Merger.

Contractual Obligations

	2006	2007-2008	2009-2010	After 2010	Total
			(in millions)		
Long-term debt [a] --					
Principal	$153	$306	$282	$4,563	$5,304
Interest	265	496	468	4,989	6,218
Preferred stock	15	-	-	-	15
Commodity derivative obligations[b]	12	-	-	-	12
Operating leases	34	58	44	58	194
Purchase commitments[c] --					
Capital [d]	1,251	2,738	2,421	-	6,410
Coal	1,579	2,220	694	40	4,533
Nuclear fuel	44	42	25	64	175
Natural gas[e]	577	525	511	2,047	3,660
Purchased power	343	689	559	994	2,585
Long-term service agreements	7	18	24	144	193
Trusts[f] --					
Nuclear decommissioning	7	14	14	117	152
Postretirement benefits	18	41	-	-	59
DOE assessments	4	-	-	-	4
Total	$4,309	$7,147	$5,042	$13,016	$29,514

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2006, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest risk.

(b) For additional information see Notes 1 and 6 to the financial statements herein.

(c) The Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses for the last three years were $1.5 billion, $1.4 billion, and $1.2 billion, respectively.

(d) The Company forecasts capital expenditures over a five-year period. Amounts represent current estimates of total expenditures, excluding those amounts related to contractual purchase commitments for uranium and nuclear fuel conversion, enrichment, and fabrication services. At December 31, 2005, significant purchase commitments were outstanding in connection with the construction program.

(e) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on the New York Mercantile Exchange future prices at December 31, 2005.

(f) Projections of nuclear decommissioning trust contributions are based on the 2004 Retail Rate Plan. The Company forecasts postretirement trust contributions over a three-year period. No contributions related to the Company's pension trust are currently expected during this period. See Note 2 to the financial statements for additional information related to the pension and postretirement plans, including estimated benefit payments. Certain benefit payments will be made through the related trusts. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2005 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales growth, storm cost recovery and repairs, environmental regulations and expenditures, the Company's projections for postretirement benefit trust contributions, financing activities, access to sources of capital, the proposed merger of Savannah Electric and the Company, the impacts of the adoption of new accounting rules, completion of construction projects, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will", "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory change, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, and implementation of the Energy Policy Act of 2005, and also changes in environmental, tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including FERC matters and the pending EPA civil action against the Company;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and population, and business growth (and declines);
- available sources and costs of fuels;
- ability to control costs;
- investment performance of the Company's employee benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate cases related to fuel cost recovery;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due;
- the ability to obtain new short- and long-term contracts with neighboring utilities;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents similar to the August 2003 power outage in the Northeast;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports, including the Form 10-K, filed by the Company from time to time with the Securities and Exchange Commission.

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

STATEMENTS OF INCOME

For the Years Ended December 31, 2005, 2004, and 2003

Georgia Power Company 2005 Annual Report

	2005	2004	2003
		(in thousands)	
Operating Revenues:			
Retail sales	**$5,642,812**	$4,776,985	$4,309,972
Sales for resale --			
Non-affiliates	**519,673**	246,545	259,376
Affiliates	**264,989**	166,245	174,855
Other revenues	**206,729**	181,033	169,304
Total operating revenues	**6,634,203**	5,370,808	4,913,507
Operating Expenses:			
Fuel	**1,830,829**	1,232,496	1,103,963
Purchased power --			
Non-affiliates	**408,563**	304,978	258,621
Affiliates	**761,466**	671,098	516,944
Other operations	**949,722**	902,167	827,972
Maintenance	**531,168**	498,114	419,206
Depreciation and amortization	**504,248**	275,488	349,984
Taxes other than income taxes	**259,825**	227,806	212,827
Total operating expenses	**5,245,821**	4,112,147	3,689,517
Operating Income	**1,388,382**	1,258,661	1,223,990
Other Income and (Expense):			
Allowance for equity funds used during construction	**26,808**	26,659	10,752
Interest income	**6,281**	6,657	15,625
Interest expense, net of amounts capitalized	**(221,199)**	(182,370)	(182,583)
Interest expense to affiliate trusts	**(59,510)**	(44,565)	-
Distributions on mandatorily redeemable preferred securities	**-**	(15,839)	(59,675)
Other income (expense), net	**5,742**	(11,362)	(10,551)
Total other income and (expense)	**(241,878)**	(220,820)	(226,432)
Earnings Before Income Taxes	**1,146,504**	1,037,841	997,558
Income taxes	**430,812**	379,170	366,311
Net Income	**715,692**	658,671	631,247
Dividends on Preferred Stock	**693**	670	670
Net Income After Dividends on Preferred Stock	**$714,999**	$658,001	$630,577

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2005, 2004, and 2003
Georgia Power Company 2005 Annual Report

	2005	2004	2003
		(in thousands)	
Operating Activities:			
Net income	**$ 715,692**	$ 658,671	$ 631,247
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization	**592,264**	361,958	424,321
Deferred income taxes and investment tax credits, net	**231,708**	251,623	199,265
Deferred expenses - affiliates	**1,268**	(10,563)	(7,399)
Allowance for equity funds used during construction	**(26,808)**	(26,659)	(10,752)
Pension, postretirement, and other employee benefits	**(19,468)**	(15,868)	(30,225)
Tax benefit of stock options	**15,711**	9,701	11,649
Other, net	**(11,068)**	(19,764)	18,929
Changes in certain current assets and liabilities --			
Receivables	**(591,498)**	(227,204)	(4,395)
Fossil fuel stock	**2,528**	(46,730)	(17,490)
Materials and supplies	**(53,942)**	618	(7,677)
Prepaid income taxes	**(43,626)**	14,358	(3,951)
Other current assets	**4,108**	(23,672)	1,599
Accounts payable	**110,118**	132,001	(62,553)
Accrued taxes	**85,098**	(64,563)	52,348
Accrued compensation	**3,822**	(6,664)	(3,111)
Other current liabilities	**33,289**	5,836	19,845
Net cash provided from operating activities	**1,049,196**	993,079	1,211,650
Investing Activities:			
Property additions	**(842,870)**	(741,151)	(717,993)
Nuclear decommissioning trust fund purchases	**(381,235)**	(541,048)	(656,806)
Nuclear decommissioning trust fund sales	**372,536**	532,349	648,107
Purchase of property from affiliates	**-**	(339,750)	(2)
Cost of removal net of salvage	**(29,428)**	(21,756)	(28,265)
Change in construction payables, net of joint owner portion	**4,037**	413	(32,223)
Other	**(315)**	(4,961)	1,008
Net cash used for investing activities	**(877,275)**	(1,115,904)	(786,174)
Financing Activities:			
Increase (decrease) in notes payable, net	**59,509**	70,956	(220,400)
Proceeds --			
Senior notes	**625,000**	600,000	1,000,000
Pollution control bonds	**185,000**	-	-
Mandatorily redeemable preferred securities	**-**	200,000	-
Capital contributions from parent company	**149,034**	260,068	40,809
Redemptions --			
Pollution control bonds	**(185,000)**	-	-
Senior notes	**(450,000)**	(200,000)	(665,000)
Mandatorily redeemable preferred securities	**-**	(200,000)	-
Payment of preferred stock dividends	**(546)**	(654)	(696)
Payment of common stock dividends	**(556,100)**	(565,500)	(565,800)
Other	**(21,679)**	(17,247)	(22,563)
Net cash provided from (used for) financing activities	**(194,782)**	147,623	(433,650)
Net Change in Cash and Cash Equivalents	**(22,861)**	24,798	(8,174)
Cash and Cash Equivalents at Beginning of Year	**33,497**	8,699	16,873
Cash and Cash Equivalents at End of Year	**$ 10,636**	$ 33,497	$ 8,699
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $10,871, $8,920, and $5,428 capitalized, respectively)	**$250,445**	$228,190	$215,463
Income taxes (net of refunds)	**207,973**	127,115	145,048

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

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BALANCE SHEETS

At December 31, 2005 and 2004

Georgia Power Company 2005 Annual Report

Assets	2005	2004
		(in thousands)
Current Assets:		
Cash and cash equivalents	**$ 10,636**	$ 33,497
Receivables --		
Customer accounts receivable	**418,154**	317,937
Unbilled revenues	**141,875**	140,027
Under recovered regulatory clause revenues	**454,683**	345,542
Other accounts and notes receivable	**110,397**	94,377
Affiliated companies	**84,597**	17,042
Accumulated provision for uncollectible accounts	**(8,647)**	(7,100)
Fossil fuel stock, at average cost	**181,739**	184,267
Vacation pay	**59,190**	57,372
Materials and supplies, at average cost	**323,908**	270,422
Prepaid expenses	**70,825**	32,695
Other	**50,248**	28,262
Total current assets	**1,897,605**	1,514,340
Property, Plant, and Equipment:		
In service	**19,603,249**	18,681,533
Less accumulated provision for depreciation	**7,575,926**	7,217,607
	12,027,323	11,463,926
Nuclear fuel, at amortized cost	**134,798**	124,745
Construction work in progress	**563,155**	766,140
Total property, plant, and equipment	**12,725,276**	12,354,811
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**68,188**	66,192
Nuclear decommissioning trusts, at fair value	**486,591**	459,194
Other	**71,468**	64,571
Total other property and investments	**626,247**	589,957
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**500,882**	505,664
Prepaid pension costs	**476,458**	450,270
Deferred under recovered regulatory clause revenues	**295,116**	-
Other regulatory assets	**330,483**	246,462
Other	**195,716**	160,834
Total deferred charges and other assets	**1,798,655**	1,363,230
Total Assets	**$17,047,783**	$15,822,338

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

BALANCE SHEETS
At December 31, 2005 and 2004
Georgia Power Company 2005 Annual Report

Liabilities and Stockholder's Equity	2005	2004
		(in thousands)
Current Liabilities:		
Securities due within one year	$ 167,317	$ 452,498
Notes payable	267,743	208,233
Accounts payable --		
Affiliated	285,019	194,253
Other	360,455	310,763
Customer deposits	129,293	115,661
Accrued taxes --		
Income taxes	150,896	78,269
Other	204,778	129,520
Accrued interest	88,885	74,529
Accrued vacation pay	45,602	44,894
Accrued compensation	137,303	127,340
Other	120,312	83,632
Total current liabilities	1,957,603	1,819,592
Long-term Debt (See accompanying statements)	4,179,218	3,709,852
Long-term Debt Payable to Affiliated Trusts (See accompanying statements)	969,073	969,073
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	2,730,303	2,556,040
Deferred credits related to income taxes	158,759	170,973
Accumulated deferred investment tax credits	287,726	300,018
Employee benefit obligations	358,137	331,002
Asset retirement obligations	627,465	504,515
Other cost of removal obligations	404,614	411,692
Other regulatory liabilities	97,015	84,678
Other	63,335	59,733
Total deferred credits and other liabilities	4,727,354	4,418,651
Total Liabilities	11,833,248	10,917,168
Preferred Stock (See accompanying statements)	-	14,609
Common Stockholder's Equity (See accompanying statements)	5,214,535	4,890,561
Total Liabilities and Stockholder's Equity	$17,047,783	$15,822,338
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2005 and 2004
Georgia Power Company 2005 Annual Report

	2005	2004	2005	2004
	(in thousands)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable --				
5.50% due December 1, 2005	$ -	$ 150,000		
Variable rate (1.66% to 1.96% at 1/1/05) due 2005	-	300,000		
6.20% due February 1, 2006	**150,000**	150,000		
4.875% due July 15, 2007	**300,000**	300,000		
4.10% due August 15, 2009	**125,000**	125,000		
Variable rate (4.53% at 1/1/06) due 2009	**150,000**	150,000		
4.00% to 6.00% due 2011-2045	**1,850,000**	1,225,000		
Total long-term notes payable	**2,575,000**	2,400,000		
Other long-term debt --				
Pollution control revenue bonds -- non-collateralized:				
2.83% to 5.45% due 2012-2034	**812,560**	812,560		
Variable rate (2.82% to 3.08% at 1/1/06) due 2011-2032	**873,330**	873,330		
Total other long-term debt	**1,685,890**	1,685,890		
Capitalized lease obligations	**74,484**	76,982		
Unamortized debt premium (discount), net	**(3,448)**	(522)		
Total long-term debt (annual interest requirement -- $205.5 million)	**4,331,926**	4,162,350		
Less amount due within one year	**152,708**	452,498		
Long-term debt excluding amount due within one year	**4,179,218**	3,709,852	**40.3%**	38.7%
Long-term Debt Payable to Affiliated Trusts:				
4.88% to 7.13% due 2042 (annual interest requirement -- $59.5 million)	**969,073**	**969,073**	**9.4**	10.1
Cumulative Preferred Stock:				
$100 stated value at 4.60%				
Authorized -- 5,000,000 shares				
Outstanding -- 145,689 shares (annual dividend requirement -- $0.7 million)	**14,609**	14,609		
Less amount due within one year	**14,609**	-		
Total cumulative preferred stock excluding amount due within one year	**-**	14,609	**0.0**	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	**2,643,012**	2,478,268		
Retained earnings	**2,261,698**	2,102,798		
Accumulated other comprehensive income (loss)	**(34,425)**	(34,755)		
Total common stockholder's equity	**5,214,535**	4,890,561	**50.3**	51.0
Total Capitalization	**$10,362,826**	$9,584,095	**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, 2005, 2004, and 2003

Georgia Power Company 2005 Annual Report

	Common Stock	Paid-In Capital	Retained Earnings	Other Comprehensive Income (loss)	Total
			(in thousands)		
Balance at December 31, 2002	$344,250	$2,156,080	$1,945,520	$(11,403)	$4,434,447
Net income after dividends on preferred stock	-	-	630,577	-	630,577
Capital contributions from parent company	-	52,458	-	-	52,458
Other comprehensive income (loss)	-	-	-	(11,471)	(11,471)
Cash dividends on common stock	-	-	(565,800)	-	(565,800)
Balance at December 31, 2003	**344,250**	**2,208,538**	**2,010,297**	**(22,874)**	**4,540,211**
Net income after dividends on preferred stock	-	-	658,001	-	658,001
Capital contributions from parent company	-	269,769	-	-	269,769
Other comprehensive income (loss)	-	-	-	(11,881)	(11,881)
Cash dividends on common stock	-	-	(565,500)	-	(565,500)
Other	-	(39)	-	-	(39)
Balance at December 31, 2004	**344,250**	**2,478,268**	**2,102,798**	**(34,755)**	**4,890,561**
Net income after dividends on preferred stock	-	-	**714,999**	-	**714,999**
Capital contributions from parent company	-	**164,745**	-	-	**164,745**
Other comprehensive income (loss)	-	-	-	**330**	**330**
Cash dividends on common stock	-	-	**(556,100)**	-	**(556,100)**
Other	-	**(1)**	**1**	-	-
Balance at December 31, 2005	**$344,250**	**$2,643,012**	**$2,261,698**	**$(34,425)**	**$5,214,535**

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

STATEMENTS OF COMPREHENSIVE INCOME

For the Years Ended December 31, 2005, 2004, and 2003

Georgia Power Company 2005 Annual Report

	2005	2004	2003
		(in thousands)	
Net income after dividends on preferred stock	**$714,999**	$658,001	$630,577
Other comprehensive income (loss):			
Change in additional minimum pension liability, net of tax of $(1,981), $(3,861) and $(5,133), respectively	**(3,140)**	(6,122)	(8,138)
Change in fair value of marketable securities, net of tax of $317 and $(114)	**501**	(181)	-
Changes in fair value of qualifying hedges, net of tax of $1,214, $(5,046) and $(3,241), respectively	**1,925**	(7,999)	(5,550)
Less: Reclassification adjustment for amounts included in net income, net of tax of $848, $1,528 and $1,208, respectively	**1,044**	2,421	2,217
Total other comprehensive income (loss)	**330**	(11,881)	(11,471)
Comprehensive Income	**$715,329**	$646,120	$619,106

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Georgia Power Company (Company) is a wholly owned subsidiary of Southern Company, which is the parent company of five retail operating companies, Southern Power Company (Southern Power), Southern Company Services (SCS), Southern Communications Services (SouthernLINC Wireless), Southern Company Holdings (Southern Holdings), Southern Nuclear Operating Company (Southern Nuclear), Southern Telecom, and other direct and indirect subsidiaries. The retail operating companies -- Alabama Power, the Company, Gulf Power, Mississippi Power, and Savannah Electric -- provide electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast. Southern Power constructs, owns, and manages Southern Company's competitive generation assets and sells electricity at market-based rates in the wholesale market. Contracts among the retail operating companies and Southern Power -- related to jointly owned generating facilities, interconnecting transmission lines, or the exchange of electric power -- are regulated by the Federal Energy Regulatory Commission (FERC). SCS -- the system service company -- provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications services to the retail operating companies and also markets these services to the public within the Southeast. Southern Telecom provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding subsidiary for Southern Company's investments in synthetic fuels and leveraged leases and various other energy-related businesses. Southern Nuclear operates and provides services to Southern Company's nuclear power plants. In January 2006, Southern Company completed the sale of substantially all the assets of Southern Company Gas, its competitive retail natural gas marketing subsidiary.

The equity method is used for subsidiaries in which the Company has significant influence but does not control and for variable interest entities where the Company is not the primary beneficiary. Certain prior years' data presented in the financial statements have been reclassified to conform to current year presentation.

Southern Company was registered as a holding company under the Public Utility Holding Company Act of 1935, as amended (PUHCA), until its repeal on February 8, 2006, and Southern Company and its subsidiaries, including the Company, were subject to the regulatory provisions of the PUHCA. The Company is subject to regulation by the FERC and the Georgia Public Service Commission (PSC). The Company follows accounting principles generally accepted in the United States and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires the use of estimates and the actual results may differ from those estimates.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, purchasing, accounting and statistical analysis, finance and treasury, tax, information resources, marketing, auditing, insurance and pension administration, human resources, systems and procedures, and other services with respect to business and operations and power pool operations. Costs for these services amounted to $330 million in 2005, $292 million in 2004, and $303 million in 2003. Cost allocation methodologies used by SCS were approved by the Securities and Exchange Commission prior to the repeal of the PUHCA 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 $328 million in 2005, $311 million in 2004, and $289 million in 2003.

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. Billings under these agreements with Southern Power amounted to $5.2 million in 2005, $4.8 million in 2004, and $5.3 million in 2003.

The Company has an agreement with SouthernLINC Wireless under which the Company receives digital wireless communications services and purchases digital equipment. Costs for these services amounted to $7.3 million in 2005, $7.7 million in 2004, and $7.4 million in 2003.

Southern Company holds a 30 percent ownership in Alabama Fuel Products, LLC (AFP), which produces synthetic fuel. The Company has an agreement with an indirect subsidiary of Southern Company that provides services for AFP. Under this agreement, the Company provides certain accounting functions, including processing and paying fuel transportation invoices, and the Company is reimbursed for its expenses. Amounts billed under this agreement totaled approximately $61 million in 2005, $53 million in 2004, and $38 million in 2003. In addition, the Company purchases synthetic fuel from AFP for use at plants Branch, McDonough, and Bowen. Fuel purchases totaled $216 million in 2005, $163 million in 2004, and $91 million in 2003.

The Company has entered into several purchased power agreements (PPAs) with Southern Power for capacity and energy. Expenses associated with these PPAs were $419 million, $282 million, and $203 million in 2005, 2004, and 2003, respectively. Additionally, the Company recorded a reduction of $1 million and an increase of $11 million of prepaid capacity expenses included on the balance sheets at December 31, 2005 and 2004, respectively. See Note 7 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, the Company operates Plant Scherer, and Gulf Power reimburses the Company for its proportionate share of the related expenses which were $4.3 million in 2005, $6.8 million in 2004, and $4.9 million in 2003. The Company has an agreement with Savannah Electric under which the Company jointly owns a portion of Plant McIntosh. Under this agreement, Savannah Electric operates Plant McIntosh, and the Company reimburses Savannah Electric for its proportionate share of the related expenses which were $5.5 million in 2005, $3.3 million in 2004, and $3.7 million in 2003. See Note 4 for additional information.

The Company provides incidental services to other Southern Company subsidiaries which are generally minor in duration and amount. However, with the hurricane damage experienced by Alabama Power, Gulf Power, and Mississippi Power in the last two years, assistance provided to aid in storm restoration, including company labor, contract labor, and materials, has caused an increase in these activities. The total amount of storm assistance provided to Alabama Power, Gulf Power, and Mississippi Power in 2005 was $4.1 million, $4.4 million, and $55 million, respectively. The total amount of storm assistance provided to Alabama Power and Gulf Power in 2004 was $4.1 million and $6.4 million, respectively. These activities were billed at cost.

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

The retail operating companies, including the Company, and Southern Power 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 7 under "Fuel Commitments" for additional information.

The Company has entered into an agreement to merge with Savannah Electric. See Note 3 under "Retail Regulatory Matters – Merger" 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.

Regulatory assets and (liabilities) reflected in the Company's balance sheets at December 31 relate to the following:

	2005	2004	Note
	(in millions)		
Deferred income tax charges	$ 501	$506	(a)
Premium on reacquired debt	170	177	(b)
Corporate building lease	52	53	(e)
Vacation pay	59	57	(d)
Postretirement benefits	18	20	(e)
DOE assessments	6	10	(c)
Generating plant outage costs	46	40	(g)
Other regulatory assets	33	11	(e)
Asset retirement obligation	65	(20)	(a)
Other cost of removal obligations	(404)	(412)	(a)
Deferred income tax credits	(159)	(171)	(a)
Environmental remediation	(19)	(22)	(f)
Purchased power	(33)	-	(f)
Other regulatory liabilities	(30)	(6)	(e)
Total	$ 305	$243	

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

(a) Asset retirement and removal liabilities are recorded, deferred income tax assets are recovered, and deferred tax liabilities are amortized over the related property lives, which may range up to 60 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities.

(b) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue which may range up to 50 years.

(c) Assessments for the decontamination and decommissioning of the DOE's nuclear fuel enrichment facilities are recorded annually from 1993 through 2006.

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

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

(f) Amortized over a three-year period ending in 2007. See Note 3 under "Retail Regulatory Matters - Rate Plans."

(g) See "Property, Plant, and Equipment" herein.

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, including plant, exists and, if impaired, write down the assets to their fair value. All regulatory assets and liabilities are reflected in rates.

Revenues

Energy and other revenues are recognized as services are provided. Unbilled revenues are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between the actual recoverable costs and amounts billed in current regulated rates.

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

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense includes the cost of purchased emission allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel. Total charges for nuclear fuel included in fuel expense amounted to $70 million in 2005, $73 million in 2004, and $74 million in 2003.

Nuclear Fuel Disposal Costs

The Company has contracts with the U.S. Department of Energy (DOE) that provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent nuclear fuel in 1998 as required by the contracts, and the Company is pursuing legal remedies against the government for breach of contract. Sufficient pool storage capacity for spent fuel is available at Plant Vogtle to maintain full-core discharge capability for both units into 2015. Construction of an on-site dry storage facility at Plant Vogtle is expected to begin in sufficient time to maintain pool full-core discharge capability. At Plant Hatch, an on-site dry storage facility is operational and can be expanded to accommodate spent fuel through the life of the plant.

Also, the Energy Policy Act of 1992 required the establishment of a Uranium Enrichment Decontamination and Decommissioning Fund, which is funded in part by a special assessment on utilities with nuclear plants. This assessment has been paid over a 15-

year period; the final installment is scheduled to occur in 2006. 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 interest, estimates its remaining liability at December 31, 2005 under this law to be approximately $4 million.

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.

Manufacturer's Tax Credits

The State of Georgia provides a tax credit for qualified investment property to manufacturing companies that construct new facilities. The credit ranges from 1 percent to 8 percent of qualified construction expenditures depending upon the county in which the new facility is located. The Company's policy is to recognize these credits when management believes that they are more likely than not to be allowed by the Georgia Department of Revenue. Manufacturer's tax credits of $12.5 million, $12.9 million, and $12.0 million were recorded in 2005, 2004, and 2003, respectively.

Property, Plant, and Equipment

The Company's property, plant, and equipment consisted of the following at December 31 (in millions):

	2005	2004
Generation	**$ 9,571**	$ 9,002
Transmission	**2,994**	2,870
Distribution	**5,953**	5,744
General	**1,057**	1,038
Plant acquisition adjustment	**28**	28
Total plant in service	**$ 19,603**	$18,682

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

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense as incurred or performed with the exception of certain generating plant maintenance costs. As mandated by the Georgia PSC, the Company defers and amortizes nuclear refueling costs over the unit's operating cycle before the next refueling. The refueling cycles are 18 and 24 months for plants Vogtle and Hatch, respectively. In accordance with the Georgia PSC 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.

Depreciation and Amortization

Depreciation of the original cost of plant in service is provided primarily by using composite straight-line rates, which approximated 2.6 percent in 2005, 2.6 percent in 2004, and 2.7 percent in 2003. Depreciation studies are conducted periodically to update the composite rates that are approved by the Georgia PSC. In connection with the new retail rate plan for the Company ending December 31, 2007 (2004 Retail Rate Plan), effective January 1, 2005, the depreciation rates were revised by the Georgia PSC. The revised depreciation rates had no material impact on the Company's financial statements.

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.

Under the three-year retail rate plan for the Company ending December 31, 2004 (2001 Retail Rate Plan), the Company discontinued recording accelerated depreciation and amortization. Also, the Company was ordered to amortize $333 million, the cumulative balance previously expensed, equally over three years as a credit to amortization expense beginning January

2002. Additionally, the Company was ordered to recognize new Georgia PSC certified purchased power costs in rates evenly over the three years covered by the 2001 Retail Rate Plan. As a result of the purchased power regulatory adjustment, the Company recorded amortization expenses of $14 million in 2003. The Company recorded a credit to amortization expense of $77 million in 2004. See Note 3 under "Retail Regulatory Matters - Rate Plans" for additional information.

Asset Retirement Obligations and Other Costs of Removal

Effective January 1, 2003, the Company adopted FASB Statement No. 143, Accounting for Asset Retirement Obligations. Statement No. 143 established new accounting and reporting standards for legal obligations associated with the ultimate costs of retiring long-lived assets. The present value of the ultimate costs for an asset's future retirement is recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In addition, effective December 31, 2005, the Company adopted the provisions of FASB Interpretation No. 47, Conditional Asset Retirement Obligations (FIN 47), which requires that an asset retirement obligation be recorded even though the timing and/or method of settlement are conditional on future events. Prior to December 2005, the Company did not recognize asset retirement obligations for asbestos removal because the timing of their retirements was dependent on future events. The Company has received approval from the Georgia PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations will continue to be reflected on the balance sheets as a regulatory liability. Therefore, the Company had no cumulative effect to net income resulting from the adoption of Statement No. 143 or FIN 47.

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. The fair value of assets legally restricted for settling retirement obligations related to nuclear facilities as of December 31, 2005 was $487 million. In addition, the Company has recognized retirement obligations related to various landfill sites, ash ponds, and underground storage tanks. The Company also recorded additional asset retirement obligations (and assets) of approximately $91 million related to asbestos removal. The Company has also identified retirement obligations related to certain transmission and distribution facilities, leasehold improvements, equipment on customer property, and property associated with the Company's rail lines. However, liabilities for the removal of these assets have not been 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 allowed removal costs in accordance with its regulatory treatment. Any difference between costs recognized under Statement No. 143 and FIN 47 and those reflected in rates are recognized as either a regulatory asset or liability in the balance sheets as ordered by the Georgia PSC. See "Nuclear Decommissioning" herein for further information on amounts included in rates.

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

	2005	2004
	(in millions)	
Balance beginning of year	**$505**	$476
Liabilities incurred	**91**	-
Liabilities settled	**(2)**	(2)
Accretion	**33**	31
Balance end of year	**$627**	$505

If FIN 47 had been adopted as of December 31, 2004, the pro forma asset retirement obligations would have been $591 million.

Nuclear Decommissioning

The Nuclear Regulatory Commission (NRC) requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has external trust funds to comply with the NRC's regulations. Use of the funds is restricted to nuclear decommissioning activities and the funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and state PSCs, as well as the Internal Revenue Service (IRS). The trust funds are invested in a tax-

efficient manner in a diversified mix of equity and fixed income securities and are classified as available-for-sale. The trust funds are included in the balance sheets at fair value, as obtained from quoted market prices for the same or similar investments. Details of the securities held in these trusts at December 31 are as follows:

2005	Unrealized Gains	Unrealized Losses	Fair Value
		(in millions)	
Equity	$76.7	$(6.3)	$325.5
Debt	2.8	(0.8)	135.3
Other	-	-	25.8
Total	**$79.5**	**$(7.1)**	**$486.6**

2004	Unrealized Gains	Unrealized Losses	Fair Value
		(in millions)	
Equity	$68.7	$(4.0)	$308.2
Debt	5.3	(0.1)	138.0
Other	-	-	13.0
Total	$74.0	$(4.1)	$459.2

The contractual maturities of debt securities at December 31, 2005 are as follows: $3.2 million in 2006; $34.9 million in 2007-2010; $32.4 million in 2011-2015; and $57.2 million thereafter.

Sales of the securities held in the trust funds resulted in proceeds of $372.5 million, $532.3 million, and $648.1 million in 2005, 2004, and 2003, respectively, all of which were re-invested. Net realized gains (losses) were $12.6 million, $14.1 million, and $21.3 million in 2005, 2004, and 2003, respectively. Realized gains and losses are determined on a specific identification basis. In accordance with regulatory guidance, all realized and unrealized gains and losses are included in the regulatory liability for Asset Retirement Obligations in the balance sheets and are not included in net income or other comprehensive income. Unrealized gains and losses are considered non-cash transactions for purposes of the statements of cash flow. Unrealized losses were not material in any period presented and do not represent any impairment of the underlying investments.

Amounts previously recorded in internal reserves are being transferred into the external trust funds over periods approved by the Georgia PSC. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed plans with the NRC to ensure that, over time -- the deposits and earnings of the external trust funds will provide the minimum funding amounts prescribed by the NRC. Annual provisions for nuclear decommissioning are based on an annuity method as approved by the Georgia PSC. The amount expensed in 2005 and fund balances were as follows:

	Plant Hatch	Plant Vogtle
	(in millions)	
Amount expensed in 2005	$ -	$ 7
Accumulated provisions:		
External trust funds, at fair value	$313	$174
Internal reserves	-	1
Total	$313	$175

Site study cost is the estimate to decommission a specific facility as of the site study year. The estimated costs of decommissioning based on the most current study performed in 2003 for the Company's ownership interests in plants Hatch and Vogtle were as follows:

	Plant Hatch	Plant Vogtle
Decommissioning periods:		
Beginning year	2034	2027
Completion year	2065	2048
	(in millions)	
Site study costs:		
Radiated structures	$497	$452
Non-radiated structures	49	58
Total	$546	$510

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

Under the 2001 Retail Rate Plan, the Georgia PSC approved the annual decommissioning costs for ratemaking of $9 million. This amount was based on the NRC generic estimate to decommission the radioactive

portion of the facilities as of 2000. The estimates were $383 million and $282 million for plants Hatch and Vogtle, respectively. Significant assumptions used to determine the costs for ratemaking included an estimated inflation rate of 4.7 percent and an estimated trust earnings rate of 6.5 percent.

Under the 2004 Retail Rate Plan, effective January 1, 2005, the Georgia PSC decreased the annual decommissioning costs for ratemaking to $7 million. This amount is based on the NRC generic estimate to decommission the radioactive portion of the facilities as of 2003. The estimates are $421 million and $326 million for plants Hatch and Vogtle, respectively. Significant assumptions used to determine the costs for ratemaking include an estimated inflation rate of 3.1 percent and an estimated trust earnings rate of 5.1 percent. Another significant assumption used was the change in the operating license for Plant Hatch. In January 2002, the NRC granted the Company a 20-year extension of the licenses for both units at Plant Hatch which permits the operation of units 1 and 2 until 2034 and 2038, respectively. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for the anticipated cost of decommissioning.

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

In accordance with regulatory treatment, the Company records AFUDC. AFUDC represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, it increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation expense. Interest related to the construction of new facilities not included in the Company's retail rates is capitalized in accordance with standard interest capitalization requirements. For the years 2005, 2004, and 2003, the average AFUDC rates were 8.02 percent, 8.22 percent, and 5.51 percent, respectively. AFUDC and interest capitalized, net of taxes, were 4.7 percent and 4.9 percent of net income after dividends on preferred stock for 2005 and 2004, respectively, and less than 3 percent for 2003.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment provision is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change. See Note 3 under "Retail Regulatory Matters" and "Plant McIntosh Construction Project" for information regarding a regulatory disallowance by the Georgia PSC in December 2004.

Storm Damage Reserve

The Company maintains a reserve for property damage to cover the cost of damages from major storms to its transmission and distribution lines and the cost of uninsured damages to its generation facilities and other property as mandated by the Georgia PSC. The Company accrues $6.3 million annually that is recoverable through base rates. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for storm damage costs.

Environmental Cost Recovery

Under Georgia PSC ratemaking provisions, $22 million has been deferred in a regulatory liability account related to certain environmental insurance settlements. Under the 2004 Retail Rate Plan, this regulatory liability is being amortized over a three-year period beginning January 1, 2005. However, the Georgia PSC also approved an annual environmental accrual of $5.4 million. Environmental remediation expenditures are charged against the reserve as they are incurred. The annual accrual amount will be reviewed and adjusted in future regulatory proceedings.

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 average costs 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.

Fuel Inventory

Fuel inventory includes the average costs of oil, coal, natural gas, and emission allowances. Fuel is charged to inventory when purchased and then expensed as used. Emission allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Stock Options

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

For pro forma purposes, the Company generally recognizes stock option expense on a straight-line basis over the vesting period. Stock options granted to employees who are eligible for retirement are expensed at the grant date.

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

Net Income	As Reported	Options Impact	Pro Forma
		(in millions)	
2005	**$715**	**$(3)**	**$712**
2004	$658	(3)	$655
2003	$631	(4)	$627

The estimated fair value of stock options granted in 2005, 2004, and 2003 was derived using the Black-Scholes stock option pricing model. The following table shows the assumptions and the weighted average fair values of stock options.

	2005	2004	2003
Interest rate	**3.90%**	3.10%	2.70%
Average expected life of stock options (in years)	**5.0**	5.0	4.3
Expected volatility of common stock	**17.90%**	19.60%	23.60%
Expected annual dividends on common stock	**$1.43**	$1.40	$1.37
Weighted average fair value of stock options granted	**$3.90**	$3.29	$3.59

See Note 8 for additional information.

Financial Instruments

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

through current period income and are recorded on a net basis in the statements of income.

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

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

	Carrying Amount	Fair Value
Long-term debt:	(in millions)	
2005	**$5,227**	**$5,195**
2004	$5,055	$5,125

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

Comprehensive Income

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

Variable Interest Entities

The primary beneficiary of a variable interest entity must consolidate the related assets and liabilities. The Company has established certain wholly-owned trusts to issue preferred securities. However, the Company is not the primary beneficiary of the trusts. Therefore, the investments in these trusts are reflected as Other Investments, and the related loans from the trusts are reflected as Long-Term Debt Payable to Affiliated Trusts on the balance sheets. See Note 6 under "Mandatorily Redeemable Preferred Securities/Long-Term Debt Payable to Affiliated Trusts" for additional information.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. The plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). In 2005, the plan was amended to provide an additional monthly supplement to certain retirees. No contributions to the plan are expected for the year ending December 31, 2006. The Company also provides certain non-qualified benefit plans for a selected group of management and highly compensated employees. Benefits under these non-qualified plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees. The Company funds related trusts to the extent required by the Georgia PSC and the FERC. For the year ended December 31, 2006, such contributions are expected to total approximately $18.4 million. The measurement date for plan assets and obligations is September 30 for each year presented.

Pension Plans

The accumulated benefit obligation for the pension plans was $1.9 billion in 2005 and $1.7 billion in 2004. Changes during the year in the projected benefit obligations, accumulated benefit obligations, and the fair value of plan assets was as follows:

	Projected Benefit Obligation	
	2005	2004
	(in millions)	
Balance at beginning of year	**$1,885**	$1,727
Service cost	**45**	42
Interest cost	**106**	101
Benefits paid	**(85)**	(85)
Plan amendments	**13**	1
Actuarial loss	**91**	99
Balance at end of year	**$2,055**	$1,885

	Plan Assets	
	2005	2004
	(in millions)	
Balance at beginning of year	**$2,181**	$2,055
Actual return on plan assets	**339**	207
Benefits paid	**(80)**	(81)
Balance at end of year	**$2,440**	$2,181

In 2005, the projected benefit obligations for the qualified and non-qualified pension plans were $1.945 billion and $110 million, respectively. All plan assets are related to the qualified plan.

Pension plan assets are managed and invested in accordance with all applicable requirements including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity, as described in the table below. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes.

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

	Plan Assets		
	Target	**2005**	2004
Domestic equity	36%	**40%**	36%
International equity	24	**24**	20
Fixed income	15	**17**	26
Real estate	15	**13**	10
Private equity	10	**6**	8
Total	100%	**100%**	100%

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

	2005	2004
	(in millions)	
Funded status	**$385**	$295
Unrecognized transition amount	**(4)**	(8)
Unrecognized prior service cost	**109**	108
Unrecognized net actuarial gain (loss)	**(54)**	21
Prepaid pension asset, net	**$436**	$416

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

	2005	2004
	(in millions)	
Prepaid pension asset	**$476**	$450
Employee benefit obligations	**(96)**	(89)
Other property and investments	**15**	19
Accumulated other comprehensive income	**41**	36
Prepaid pension asset, net	**$436**	$416

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

	2005	2004	2003
	(in millions)		
Service cost	**$ 45**	$ 42	$ 38
Interest cost	**106**	101	100
Expected return on plan assets	**(182)**	(180)	(179)
Recognized net (gain)/loss	**3**	(5)	(19)
Net amortization	**7**	7	6
Net pension (income)	**$(21)**	$(35)	$ (54)

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2005, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2006	$ 88
2007	91
2008	94
2009	97
2010	102
2011 to 2015	$607

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	
	2005	2004
	(in millions)	
Balance at beginning of year	**$726**	$723
Service cost	**10**	10
Interest cost	**41**	41
Benefits paid	**(32)**	(31)
Actuarial loss	**24**	42
Plan amendments	**-**	(59)
Balance at end of year	**$769**	$726

	Plan Assets	
	2005	2004
	(in millions)	
Balance at beginning of year	**$299**	$265
Actual return on plan assets	**38**	32
Employer contributions	**40**	33
Benefits paid	**(32)**	(31)
Balance at end of year	**$345**	$299

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

		Plan Assets	
	Target	**2005**	2004
Domestic equity	43%	**43%**	42%
International equity	21	**22**	23
Domestic fixed income	19	**19**	19
Global fixed income	11	**11**	11
Real estate	4	**3**	3
Private equity	2	**2**	2
Total	100%	**100%**	100%

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

	2005	2004
	(in millions)	
Funded status	**$(424)**	$(428)
Unrecognized transition obligation	**70**	78
Unrecognized prior service cost	**25**	27
Unrecognized net loss	**203**	203
Fourth quarter contributions	**21**	15
Employee benefit obligations recognized in the balance sheets	**$(105)**	$(105)

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

	2005	2004	2003
	(in millions)		
Service cost	**$10**	$ 10	$ 9
Interest cost	**41**	41	40
Expected return on plan assets	**(22)**	(25)	(24)
Net amortization	**18**	18	16
Net postretirement cost	**$47**	$ 44	$ 41

In the third quarter 2004, the Company prospectively adopted FASB Staff Position (FSP) 106-2, Accounting and Disclosure Requirements related to the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (Medicare Act). The Medicare Act provides a 28 percent prescription drug subsidy for Medicare eligible retirees. FSP 106-2 requires recognition of the impacts of the Medicare Act in the accumulated postretirement benefit obligation (APBO) and future cost of service for postretirement medical plans. The effect of the subsidy reduced the Company's expenses for the six months ended December 31, 2004 and for the year ended December 31, 2005 by approximately $5 million and $10 million, respectively, and is expected to have a similar impact on future expenses.

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the accumulated benefit obligation for the postretirement plans. Estimated benefit payments are reduced by drug

subsidy receipts expected as a result of the Medicare Act as follows:

	Benefit Payments	Subsidy Receipts	Total
	(in millions)		
2006	$ 37	$ (3)	$ 34
2007	39	(4)	35
2008	42	(4)	38
2009	46	(4)	42
2010	50	(5)	45
2011 to 2015	280	(34)	246

Actuarial Assumptions

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

	2005	2004	2003
Discount	**5.50%**	5.75%	6.00%
Annual salary increase	**3.00**	3.50	3.75
Long-term return on plan assets	**8.50**	8.50	8.50

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

An additional assumption used in measuring the APBO was a weighted average medical care cost trend rate of 10.25 percent for 2005, decreasing gradually to 4.75 percent through the year 2014, 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, 2005, as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$70	$62
Service and interest costs	5	4

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides a 75 percent matching contribution up to 6 percent of an employee's base salary. Total matching contributions made to the plan for the years 2005, 2004, and 2003 were $19 million, $18 million, and $18 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, and citizen enforcement of environmental requirements such as opacity and other air quality standards, 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 pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S District Court for the Northern District of Georgia against the Company and Alabama Power, alleging that the Company and Alabama Power had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws with respect to certain coal-fired generating facilities. Through subsequent amendments and other legal proceedings, the EPA added Savannah Electric as a defendant to the original action and filed a separate action against Alabama Power after it was dismissed from the original action. In these lawsuits, the

EPA alleges that NSR violations occurred at eight coal-fired generating facilities, including the Company's Plants Bowen and Scherer. The civil action requests penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. On June 3, 2005, the U.S. District for the Northern District of Alabama issued a decision in favor of Alabama Power on two primary legal issues in the case; however, the decision does not resolve the case, nor does it address other legal issues associated with the EPA's allegations. In accordance with a separate court order, Alabama Power and the EPA are currently participating in mediation with respect to the EPA's claims. The action against the Company and Savannah Electric has been administratively closed since the spring of 2001, and none of the parties has sought to reopen the case.

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $32,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in this case could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

Plant Wansley Environmental Litigation

In December 2002, the Sierra Club, Physicians for Social Responsibility, Georgia Forestwatch, and one individual filed a civil suit in the U.S. District Court for the Northern District of Georgia against the Company for alleged violations of the Clean Air Act at four of the units at Plant Wansley. 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. The liability phase of the case has concluded with the court ruling in favor of the Company in part and the plaintiffs in part. In March 2005, the U.S. Court of Appeals for the Eleventh Circuit accepted the Company's petition for review of the district court's order, and oral arguments were held on January 24, 2006. The district court case has been administratively closed pending that appeal. If necessary, the district court will hold a separate trial which will address civil penalties and possible injunctive relief requested by the plaintiffs. The ultimate outcome of this matter cannot currently be determined; however, an adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

Environmental Remediation

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. In 1995, the EPA designated the Company and four other unrelated entities as potentially responsible parties at a site in Brunswick, Georgia that is listed on the federal National Priorities List. As of December 31, 2005, the Company had recorded approximately $6 million in cumulative expenses associated with the Company's agreed-upon share of the removal and remedial investigation and feasibility study costs for the Brunswick site. Additional claims for recovery of natural resource damages at the site are anticipated. The Company has also recognized $36 million in cumulative expenses through December 31, 2005 for the assessment and anticipated cleanup of sites on the Georgia Hazardous Sites Inventory.

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 the Company'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.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates at market-based prices. The Company also has FERC authority to make short-term opportunity sales at market rates. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in that proceeding. In February 2005, Southern Company submitted responsive information. In February 2006, the FERC agreed to allow the parties to conduct settlement discussions. Any new market-based rate transactions in its retail service territory entered into after February 27, 2005 are subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. The impact of such sales through December 31, 2005 is not expected to exceed $4.9 million. The refund period covers 15 months. In the event that the FERC's default mitigation measures for entities that are found to have market power are ultimately applied, the Company may be required to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates. The final outcome of this matter will depend on the form in which the final methodology for assessing generation market power and mitigation rules may be ultimately adopted and cannot be determined at this time.

In addition, in May 2005, the FERC started an investigation to determine whether Southern Company satisfies the other three parts of the FERC's market-based rate analysis: transmission market power, barriers to entry, and affiliate abuse or reciprocal dealing. The FERC established a new refund period related to this expanded investigation. Any and all new market-based rate transactions both inside and outside Southern Company's retail service territory involving any Southern Company subsidiary, including the Company, will be subject to refund to the extent the FERC orders lower rates as a result of this new investigation, with the 15-month refund period beginning July 19, 2005. The impact of such sales through December 31, 2005 is not expected to exceed $10.9 million, of which $3.2 million relates to sales inside the retail service territory as discussed above. The FERC also directed that this expanded proceeding be held in abeyance pending the outcome of the proceeding on the IIC discussed below.

The Company believes that there is no meritorious basis for this proceeding and is vigorously defending itself in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in this proceeding, cannot now be determined.

Intercompany Interchange Contract

The Company's generation fleet in its retail service territory is operated under the IIC, as approved by the FERC. In May 2005, the FERC also initiated a new proceeding to examine (1) the provisions of the IIC among Alabama Power, the Company, Gulf Power, Mississippi Power, Savannah Electric, Southern Power, and SCS, as agent, under the terms of which the power pool of Southern Company is operated, and, in particular, the propriety of the continued inclusion of Southern Power as a party to the IIC, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining Southern Power as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of Southern Power, the FERC authorized Southern Power's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct. The FERC order directs that the administrative law judge who presided over the McIntosh PPA proceeding involving an approval of PPAs between Southern Power and the Company and Savannah Electric, be assigned to preside over the hearing in this proceeding and that the testimony and exhibits presented in that proceeding be preserved to the extent appropriate. Hearings are scheduled for September 2006. Effective July 19, 2005, revenues from transactions under the IIC involving any Southern Company subsidiaries, including the Company, are subject to refund to the extent the FERC orders any changes to the IIC.

The Company believes that there is no meritorious basis for this proceeding and is vigorously defending itself in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in this proceeding, cannot now be determined.

Generation Interconnection Agreements

In July 2003, the FERC issued its final rule on the standardization of generation interconnection agreements and procedures (Order 2003). Order 2003 shifts much of the financial burden of new transmission investment from the generator to the transmission provider. The FERC has indicated that Order 2003, which was effective January 20, 2004, is to be applied prospectively to interconnection

agreements. Subsidiaries of Tenaska, Inc., as counterparties to previously executed interconnection agreements with the Company and another Southern Company subsidiary, have filed complaints at the FERC requesting that the FERC modify the agreements and that the Company refund a total of $7.9 million previously paid for interconnection facilities, with interest. The Company has opposed such relief and the proceedings are still pending. The impact of Order 2003 and its subsequent rehearings on the Company and the final results of these matters cannot be determined at this time.

Race Discrimination Litigation

In July 2000, a lawsuit alleging race discrimination was filed by three of the Company's employees against the Company, Southern Company, and SCS in the Superior Court of Fulton County, Georgia. Shortly thereafter, the lawsuit was removed to the U.S. District Court for the Northern District of Georgia and amended to add four more plaintiffs. The lawsuit also raised claims on behalf of a purported class. The plaintiffs sought compensatory and punitive damages in an unspecified amount, as well as injunctive relief.

Following various court decisions in favor of the defendants and subsequent appeals by the plaintiffs, on July 13, 2005, the plaintiffs filed a petition for writ of certiorari to the U.S. Supreme Court. On October 17, 2005, the petition was denied. This matter is now concluded.

Right of Way Litigation

Southern Company and certain of its subsidiaries, including the Company, Gulf Power, Mississippi Power, and Southern Telecom, have been named as defendants in numerous lawsuits brought by landowners since 2001. 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 exceed the easements or other property rights held by defendants. The plaintiffs assert claims for, among other things, trespass and unjust enrichment, and seek compensatory and punitive damages and injunctive relief. Management believes that the Company has complied with applicable laws and that the plaintiffs' claims are without merit.

In January 2005, the Superior Court of Decatur County, Georgia granted partial summary judgment in a lawsuit brought by landowners against the Company based on the plaintiffs' declaratory judgment claim that the easements do not permit general telecommunications use. The Company appealed this ruling to the Georgia Court of Appeals. The Georgia Court of Appeals reversed, in part, the court's order and remanded the case to the trial court for the determination of further issues. After the Court of Appeals' decision, the plaintiffs filed a motion for reconsideration, which was denied, and a petition for certiorari to the Georgia Supreme Court, which is currently pending. The question of damages and other liabilities or remedies issues with respect to this action, if any, will be decided at a future trial. In the event of an adverse verdict in the case, the Company could appeal both liability and damages or other relief granted. An adverse outcome in these matters could result in substantial judgments; however, the final outcome cannot now be determined.

In addition, in late 2001, certain subsidiaries of Southern Company, including Alabama Power, the Company, Gulf Power, Mississippi Power, Savannah Electric, and Southern Telecom, were named as defendants in a lawsuit brought by a telecommunications company that uses certain of the defendants' rights of way. This lawsuit alleges, among other things, that the defendants are contractually obligated to indemnify, defend, and hold harmless the telecommunications company from any liability that may be assessed against it in pending and future right of way litigation. The Company believes that the plaintiff's claims are without merit. In the fall of 2004, the trial court stayed the case until resolution of the underlying landowner litigation discussed above. In January 2005, the Georgia Court of Appeals dismissed the telecommunications company's appeal of the trial court's order for lack of jurisdiction. An adverse outcome in this matter, combined with an adverse outcome against the telecommunications company in one or more of the right of way lawsuits, could result in substantial judgments; however, the final outcome of these matters cannot now be determined.

Property Tax Dispute

The Company is involved in a significant property tax dispute with Monroe County, Georgia (Monroe County). The Monroe County Board of Tax Assessors (Monroe Board) has issued assessments reflecting substantial

increases in the ad valorem tax valuation of the Company's 22.95 percent ownership interest in Plant Scherer, which is located in Monroe County, for tax years 2003, 2004, and 2005. The Company is aggressively pursuing administrative appeals in Monroe County and has filed notices of arbitration for all three years. The appeals are currently stayed, pending the outcome of the litigation discussed below.

In November 2004, the Company filed suit, on its behalf, against the Monroe Board in the Superior Court of Monroe County. The Company contends that Monroe County acted without statutory authority in changing the valuation of a centrally assessed utility as established by the Revenue Commissioner of the State of Georgia and requests injunctive relief prohibiting Monroe County and the Monroe Board from unlawfully changing the value of Plant Scherer and ultimately collecting additional ad valorem taxes from the Company. On December 22, 2005, the court granted Monroe County's motion for summary judgment. The Company has filed an appeal of the Superior Court's decision to the Georgia Supreme Court.

If the Company is not successful in its administrative appeals and if Monroe County is successful in defending the litigation, the Company could be subject to total additional taxes through December 31, 2005 of up to $13 million, plus penalties and interest. The ultimate outcome of this matter cannot currently be determined.

Retail Regulatory Matters

Merger

On December 13, 2005, the Company and Savannah Electric entered into an Agreement and Plan of Merger. Savannah Electric will merge into the Company, with the Company continuing as the surviving corporation (the Merger). At the effective time of the Merger, each share of the Company's common stock will remain issued and outstanding; each share of the Company's preferred stock issued and outstanding will have been redeemed prior to the Merger; the issued and outstanding shares of Savannah Electric common stock, all of which are held by Southern Company, will be converted into the right to receive 1,500,000 shares of the Company's common stock; and each share of Savannah Electric preferred stock issued and outstanding immediately prior to the Merger will be converted into the right to receive one share of a new series of the Company's Class A Preferred Stock. The Merger must be approved by the preferred shareholders of Savannah Electric and is subject to the receipt of certain regulatory approvals from the FERC, the Georgia PSC, and the Federal Communications Commission. Pending regulatory approvals, the Merger is expected to be completed by July 2006. The Merger is not expected to have a material impact on the Company's financial statements.

While the Georgia PSC does not have specific approval authority over the merger of electric utilities, the Company and Savannah Electric have filed an application with the Georgia PSC with respect to certain approvals that will be necessary to effectively complete the Merger. In particular, the Company and Savannah Electric plan to seek the approval of the Georgia PSC with respect to the following matters:

- the transfer of Savannah Electric's generating facilities and certification of the generating facilities as the Company's assets;
- amendments to the Company's Integrated Resource Plan to add the current Savannah Electric's customers and generating facilities;
- the transfer of Savannah Electric's assigned service territory to the Company;
- adoption of the Company's service rules and regulations to the current Savannah Electric customers;
- new fuel rate and base rate schedules that would apply to the Company's sale of electricity to the current Savannah Electric customers;
- adoption of a "merger transition adjustment" rate that would be used to more closely align Savannah Electric's existing base rates to those of the Company and a "merger transition credit" rate that would credit the additional revenues collected from former Savannah Electric customers to the Company's existing customers; and
- the issuance of additional shares of the Company's common stock to Southern Company in exchange for Southern Company's shares of Savannah Electric common stock.

Rate Plans

Under the terms of the 2004 Retail Rate Plan, which the Georgia PSC approved in December 2004, the Company's earnings are evaluated against a retail return on common equity (ROE) range of 10.25 percent to 12.25 percent. Two-thirds of any earnings

above 12.25 percent will be applied to rate refunds, with the remaining one-third retained by the Company. Retail rates were increased by approximately $194 million and customer fees by approximately $9 million effective January 1, 2005 to cover the higher costs of purchased power; operating and maintenance expenses; environmental compliance; and continued investment in new generation, transmission, and distribution facilities to support growth and ensure reliability. In 2005, the Company recorded $2.7 million in revenue subject to refund related to earnings in excess of 12.25 percent retail ROE.

The Company is required to file a general rate case by July 1, 2007, in response to which the Georgia PSC would be expected to determine whether the rate order should be continued, modified, or discontinued. Until then, the Company may not file for a general base rate increase unless its projected retail ROE falls below 10.25 percent.

Under the 2001 Retail Rate Plan, retail rates were decreased by $118 million effective January 1, 2002. Under the terms of the 2001 Retail Rate Plan, earnings were evaluated against a retail ROE range of 10 percent to 12.95 percent. Two-thirds of any earnings above the 12.95 percent return were to be applied to rate refunds, with the remaining one-third retained by the Company. The Company's earnings in 2004, 2003, and 2002 were within the retail ROE range.

Under the 2001 Retail Rate Plan, the Company discontinued recording accelerated depreciation and amortization and began amortizing the accumulated balance equally over three years as a credit to expense beginning in 2002. Also, the 2001 Retail Rate Plan required the Company to recognize capacity and operating and maintenance costs related to new Georgia PSC-certified PPAs evenly in rates over a three-year period ended December 31, 2004.

Fuel Hedging Program

In 2003, the Georgia PSC approved an order allowing the Company to implement a natural gas and oil procurement and hedging program. This order allows the Company to use financial instruments to hedge price and commodity risk associated with these fuels. 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 the Company retaining 25 percent of the total net gains. In 2005, the Company had a total net gain of $64.1 million, of which the Company retained $16 million.

Fuel Cost Recovery

On May 17, 2005, the Georgia PSC approved the Company's request to increase customer fuel rates by approximately 9.5 percent to recover under recovered fuel costs of approximately $508 million existing as of May 31, 2005 over a four-year period that began June 1, 2005. Based on the order, a portion of the under recovered regulatory clause revenues was reclassified from current assets to deferred charges and other assets in the balance sheet. Under recovered fuel amounts for the periods subsequent to June 1, 2005 totaled $327.5 million through December 31, 2005. The Georgia PSC's order instructs that such amounts be reviewed semi-annually beginning February 2006. If the amount under or over recovered exceeds $50 million at the evaluation date, the Company would be required to file for a temporary fuel rate change. In addition, Savannah Electric's under recovered fuel costs totaled $77.7 million at December 31, 2005. In accordance with the Georgia PSC order, Savannah Electric was scheduled to file an additional request for a fuel cost recovery increase in January 2006. The Company has agreed with a Georgia PSC staff recommendation to forego the temporary fuel rate process, and Savannah Electric has postponed its scheduled filing. Instead, the Company and Savannah Electric will file a combined request in March 2006 to increase the Company's fuel cost recovery rate.

The case will seek approval of a fuel cost recovery rate based upon future fuel cost projections for the combined Company and Savannah Electric generating fleet as well as the under recovered fuel balances existing at June 30, 2006. The new fuel cost recovery rate would be billed beginning in July 2006 to all of the Company's customers, including the existing Savannah Electric customers. Under recovered amounts as of the date of the Merger will be paid by the appropriate customer groups.

In August 2005, the Georgia PSC initiated an investigation of Savannah Electric's fuel practices. In February 2006, an investigation of the Company's fuel

practices was initiated. The Company and Savannah Electric are responding to data requests and cooperating in the investigations. The final outcome of this matter cannot now be determined.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable cost and amounts billed in current regulated rates. Accordingly, any increase in the billing factor would have no significant effect on the Company's revenues or net income, but would increase annual cash flow.

Nuclear Performance Standards

Through December 2004, the Georgia PSC had adopted a three-year performance standard for the Company's nuclear generating units. The performance standard was 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. For the period 2002-2004, the Company's performance fell within the criteria prescribed by the Georgia PSC; there was no associated award or penalty. Effective January 1, 2005, the Georgia PSC discontinued the nuclear performance standard.

Plant McIntosh Construction Project

In December 2002 after a competitive bidding process, the Georgia PSC certified PPAs between Southern Power and the Company and Savannah Electric for capacity from Plant McIntosh Units 10 and 11, construction of which was completed in June 2005. In April 2003, Southern Power applied for FERC approval of these PPAs. In July 2003, the FERC accepted the PPAs to become effective June 1, 2005, subject to refund, and ordered that hearings be held. Intervenors opposed the FERC's acceptance of the PPAs, alleging that they did not meet the applicable standards for market-based rates between affiliates. To ensure the timely completion of the Plant McIntosh construction project and the availability of the units in the summer of 2005 for their retail customers, in May 2004, the Company and Savannah Electric requested the Georgia PSC to direct them to acquire the Plant McIntosh construction project. The Georgia PSC issued such an order and the transfer occurred on May 24, 2004 at a total cost of approximately $415 million, including approximately $14 million of transmission interconnection facilities. Subsequently, Southern Power filed a request to withdraw the PPAs and to terminate the ongoing FERC proceedings. In August 2004, the FERC issued a notice accepting the request to withdraw the PPAs and permitting such request to become effective by operation of law. However, the FERC made no determination on what additional steps may need to be taken with respect to testimony provided in the proceedings. See "FERC Matters – Intercompany Interchange Contract" herein for additional information.

In connection with the 2004 Retail Rate Plan, the Georgia PSC approved the transfer of the Plant McIntosh construction project at a total fair market value of approximately $385 million. This value reflected an approximate $16 million disallowance, of which $13 million was attributable to the Company, and reduced the Company's net income by approximately $8 million. The Georgia PSC also certified a total completion cost not to exceed $547 million for the project. In June 2005, Plant McIntosh Units 10 and 11 were placed into service at a total cost that did not exceed the certified amount. Under the 2004 Retail Rate Plan, the Plant McIntosh revenue requirements impact is being reflected in the Company's rates evenly over the three years ending 2007. See "Retail Regulatory Matters—Rate Plans" herein for additional information regarding the transfer of the Plant McIntosh construction project.

4. JOINT OWNERSHIP AGREEMENTS

The Company and an affiliate, Alabama Power, own equally all of the outstanding capital stock of SEGCO which owns electric generating units with a total rated capacity of 1,020 megawatts, as well as associated transmission facilities. The capacity of 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:

	2005	2004	2003
		(in millions)	
Energy	$54	$51	$55
Capacity	38	36	34
Total	$92	$87	$89

The Company 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 (MEAG), the city of Dalton, Georgia, Florida Power & Light Company, Jacksonville Electric Authority, and Gulf Power. Under these agreements, the Company has contracted to operate and maintain the plants as agent for the co-owners and 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 combustion- turbine common facilities and Plant McIntosh combined cycle units with Savannah Electric who operates the plants. The Company and Progress Energy Florida, Inc. jointly own a combustion turbine unit (Intercession City) operated by Progress Energy Florida, Inc.

At December 31, 2005, 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%	$3,311*	$1,809
Plant Hatch (nuclear)	50.1	935	492
Plant Wansley (coal)	53.5	395	172
Plant Scherer (coal)			
Units 1 and 2	8.4	115	56
Unit 3	75.0	562	270
Plant McIntosh CC (combined cycle)	83.9	436	7
Plant McIntosh Common Facilities (combustion-turbine)	75.0	27	5
Rocky Mountain (pumped storage)	25.4	169*	92
Intercession City (combustion-turbine)	33.3	12	2

*Investment includes write-offs

At December 31, 2005, the portion of total construction work in progress related to Plants Wansley, Scherer, and Rocky Mountain was $8.3 million, $0.5 million, and $0.1 million, respectively, primarily for environmental projects.

The Company's proportionate share of its plant operating expenses is included in the corresponding operating expenses in the statements of income.

5. INCOME TAXES

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

In 2004, in order to avoid the loss of certain federal income tax credits related to the production of synthetic fuel, Southern Company chose to defer certain

deductions otherwise available to the subsidiaries. The cash flow benefit associated with the utilization of the tax credits was allocated to the subsidiary that otherwise would have claimed the available deductions on a separate company basis without the deferral. This allocation concurrently reduced the tax benefit of the credits allocated to those subsidiaries that generated the credits. As the deferred expenses are deducted, the benefit of the tax credits will be repaid to the subsidiaries that generated the tax credits. The Company has recorded $10 million payable to these subsidiaries in Accumulated Deferred Income Taxes on the balance sheets at December 31, 2005.

The transfer of the Plant McIntosh construction project from Southern Power to the Company resulted in a deferred gain to Southern Power for federal income tax purposes. The Company will reimburse Southern Power for the remaining balance of the related deferred taxes of $5.3 million reflected in Southern Power's future taxable income. $3.7 million of this payable to Southern Power is included in Other Deferred Credits and $1.6 million is included in Affiliated Accounts Payable in the balance sheet at December 31, 2005.

The transfer of the Dahlberg, Wansley, and Franklin projects to Southern Power from the Company in 2001 and 2002 also resulted in a deferred gain for federal income tax purposes. Southern Power will reimburse the Company for the remaining balance of the related deferred taxes of $12.2 million reflected in the Company's future taxable income. $10.8 million of this receivable from Southern Power is included in Other Deferred Debits and $1.4 million is included in Affiliated Accounts Receivable in the balance sheet at December 31, 2005.

At December 31, 2005, tax-related regulatory assets were $501 million and tax-related regulatory liabilities were $159 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:

	2005	2004	2003
Total provision for income taxes:		(in millions)	
Federal:			
Current	**$173**	$116	$143
Deferred	**203**	221	181
	376	337	324
State:			
Current	**26**	12	24
Deferred	**29**	30	16
Deferred investment tax credits	**-**	-	2
Total	**$431**	$379	$366

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:

	2005	2004
	(in millions)	
Deferred tax liabilities:		
Accelerated depreciation	**$2,177**	$2,050
Property basis differences	**558**	577
Employee benefit obligations	**163**	149
Fuel clause under recovery	**305**	141
Premium on reacquired debt	**69**	72
Storm damage reserve	**13**	6
Other	**74**	81
Total	**3,359**	3,076
Deferred tax assets:		
Federal effect of state deferred taxes	**116**	106
Other property basis differences	**139**	147
Other deferred costs	**126**	94
Employee benefit obligations	**51**	55
Other comprehensive income	**23**	22
Unbilled revenue	**13**	11
Other	**33**	19
Total	**501**	454
Total deferred tax liabilities, net	**2,858**	2,622
Portion included in current (liabilities) assets, net	**(128)**	(66)
Accumulated deferred income taxes in the balance sheets	**$2,730**	$2,556

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 2005, $12 million in 2004, and $15 million in 2003. At December 31, 2005, all investment tax credits available to reduce federal income taxes payable had been utilized.

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

	2005	2004	2003
Federal statutory rate	35%	35%	35%
State income tax, net of federal deduction	3	3	3
Non-deductible book depreciation	1	1	1
Other	(1)	(2)	(2)
Effective income tax rate	38%	37%	37%

6. FINANCING

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

The Company has formed certain wholly owned trust subsidiaries for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the Company through the issuance of junior subordinated notes totaling $969 million, which constitute substantially all of the assets of the trusts and are reflected in the balance sheets as Long-Term Debt Payable to Affiliated Trusts. The Company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the respective trusts' payment obligations with respect to these securities. At December 31, 2005, preferred securities of $940 million were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for these trusts and the related securities.

Securities Due Within One Year

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

	2005	2004
	(in millions)	
Capital lease	$ 3	$ 2
Senior notes	150	450
Preferred stock	15	-
Total	$168	$452

Serial maturities through 2010 applicable to total long-term debt and preferred stock are as follows: $168 million in 2006; $303 million in 2007; $3 million in 2008; $278 million in 2009; and $4 million in 2010.

Pollution Control Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such 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, 2005 was $1.7 billion.

Senior Notes

The Company issued a total of $625 million of unsecured senior notes in 2005. The proceeds of these issues were used to redeem or repay at maturity long-term debt, to repay short-term indebtedness, and for other general corporate purposes. At December 31, 2005 and 2004, the Company had $2.6 billion and $2.4 billion of senior notes outstanding, respectively. These senior notes are subordinate to all secured debt of the Company.

Capital Leases

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, 2005 and 2004, the Company had a capitalized lease obligation for its corporate headquarters

building of $74 million and $77 million, respectively, with an interest rate of 8.1 percent. For ratemaking purposes, the Georgia PSC 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 Georgia PSC. See Note 1 under "Regulatory Assets and Liabilities."

Bank Credit Arrangements

At the beginning of 2006, the Company had credit arrangements with banks totaling $780 million, of which $778 million was unused. Of these facilities, $70 million expires at various times throughout 2006; $350 million expires in 2007, with the remaining $360 million expiring in 2010. The facilities that expire in 2006 provide the option of converting borrowings into a two-year term loan. The Company expects to renew its facilities, as needed, prior to expiration. The agreements contain stated borrowing rates. All the agreements require payment of commitment fees based on the unused portion 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. A fee is also paid to the agent bank.

The credit arrangements contain covenants that limit the level of indebtedness to capitalization to 65 percent, as defined in the arrangements. For purposes of these definitions, indebtedness excludes the long-term debt payable to affiliated trusts. In addition, the credit arrangements contain cross default provisions that would trigger an event of default if the Company defaulted on other indebtedness above a specified threshold. At December 31, 2005, the Company was in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowings.

The $778 million 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, 2005 was $106 million. In addition, the Company borrows under a commercial paper program and an extendible commercial note program. The amount of commercial paper outstanding at December 31, 2005 was $268 million. The amount of commercial paper outstanding at December 31, 2004 was $208 million. There were no outstanding extendible commercial notes at December 31, 2005. Commercial paper is included in notes payable on the balance sheets.

During 2005, the peak amount of short-term debt outstanding was $549 million and the average amount outstanding was $242 million. The average annual interest rate on short-term debt in 2005 was 3.20 percent.

Financial Instruments

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. See Note 3 under "Retail Regulatory Matters – Fuel Hedging Program" for information on the Company's fuel hedging program. The Company also enters into hedges of forward electricity sales. There was no material ineffectiveness recorded in earnings in 2005, 2004, and 2003.

At December 31, 2005, the fair value of derivative energy contracts was reflected in the financial statements as follows:

	Amounts
	(in thousands)
Regulatory liabilities, net	$26,643
Other comprehensive income	-
Net income	(81)
Total fair value	$26,562

The fair value gain or loss for hedges that are recoverable through the regulatory fuel clauses are recorded in regulatory assets and liabilities and are recognized in earnings at the same time the hedged items affect earnings. The Company has energy-related hedges in place up to and including 2008.

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

addition to interest rate swaps, the Company has also entered into certain options agreements that effectively cap its interest rate exposure in return for payment of a premium. In some cases, costless collars have been used that effectively establish a floor and a ceiling to interest rate expense.

At December 31, 2005, the Company had $1.0 billion notional amounts of interest derivatives accounted for as cash flow hedges outstanding with net fair value gains as follows:

Maturity	Weighted Average Fixed Rate Paid	Notional Amount	Fair Value Gain / (Loss)
		(in millions)	
2007	2.67%	$300	$ 2.4
2006-2007	2.09% -3.85%*	$400	$ 1.2
2037	4.58% -5.75%**	$300	$(1.1)

*Series of interest rate caps and collars (showing the lowest floor and highest cap) with variable rate based on one-month LIBOR
**Interest rate collar

The fair value gain or loss for cash flow hedges is recorded in other comprehensive income and is reclassified into earnings at the same time the hedged items affect earnings. In 2005, 2004, and 2003, the Company settled gains (losses) totaling $0.9 million, $(12.4) million, and $(11.3) million, respectively, upon termination of certain interest derivatives at the same time it issued debt. For the years 2005, 2004, and 2003, approximately $1.9 million, $3.9 million, and $3.4 million, respectively, of pre-tax losses were reclassified from other comprehensive income to interest expense. For 2006, pre-tax losses of approximately $0.5 million are expected to be reclassified from other comprehensive income to interest expense. The Company has gains/losses that are being amortized through 2017.

7. COMMITMENTS

Construction Program

The Company currently estimates property additions to be approximately $1.3 billion, $1.4 billion, and $1.3 billion in 2006, 2007, and 2008, respectively. These amounts include $44 million, $28 million, and $14 million in 2006, 2007, and 2008, respectively, for construction expenditures related to contractual purchase commitments for uranium and nuclear fuel conversion, enrichment, and fabrication services included under "Fuel Commitments" herein. 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, changes in FERC rules and transmission regulations, 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, 2005, significant purchase commitments were outstanding in connection with the construction program.

The Company completed construction of Plant McIntosh Units 10 and 11 in June 2005 and has no other generating plants currently under construction. Construction related to new transmission and distribution facilities and capital improvements to existing generation, transmission and distribution facilities, including those needed to meet environmental standards, is ongoing.

Long-Term Service Agreements

The Company and Savannah Electric have entered into a Long-Term Service Agreement (LTSA) with General Electric (GE) for the purpose of securing maintenance support for the combustion turbines at the Plant McIntosh combined cycle facility. In summary, the LTSA stipulates that GE will perform all planned inspections on the covered equipment, which includes the cost of all labor and materials. GE is also obligated to cover the costs of unplanned maintenance on the covered equipment subject to a limit specified in each contract.

In general, this LTSA is in effect through two major inspection cycles per unit. Scheduled payments to GE are made at various intervals based on actual operating hours of the respective units. Total payments to GE under this agreement are currently estimated at $186 million over the remaining term of the agreement, which may range up to 30 years. However, the LTSA contains various cancellation provisions at the option of the Company.

The Company has also entered into an LTSA with GE through 2014 for neutron monitoring system parts and electronics at Plant Hatch. Total remaining payments to GE under this agreement are currently estimated at $13.1 million. The contract contains

cancellation provisions at the option of the Company.

Payments made to GE prior to the performance of any work are recorded as a prepayment in the balance sheets. Work performed by GE is capitalized or charged to expense as appropriate net of any joint owner billings, based on the nature of the work.

Fuel Commitments

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement of fossil and nuclear fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Coal commitments include forward contract purchases for sulfur dioxide emission allowances. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery. Amounts included in the chart below represent estimates based on New York Mercantile Exchange future prices at December 31, 2005.

Total estimated minimum long-term obligations at December 31, 2005 were as follows:

	Commitments		
	Natural Gas	Coal	Nuclear Fuel
		(in millions)	
2006	$577	$1,579	$ 44
2007	325	1,313	28
2008	200	907	14
2009	257	422	11
2010	254	272	14
2011 and thereafter	2,047	40	64
Total	$3,660	$4,533	$175

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

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other Southern Company retail operating companies, Southern Power, and Southern Company Gas. Under these agreements, each of the retail operating companies, Southern Power, and Southern Company Gas may be jointly and severally liable. The creditworthiness of Southern Power and Southern Company Gas is currently inferior to the creditworthiness of the retail operating companies. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the retail 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 Company Gas as a contracting party under these agreements.

Purchased Power Commitments

The Company has commitments regarding a portion of a 5 percent interest in Plant Vogtle owned by 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 $54 million, $55 million, and $57 million in 2005, 2004, and 2003, respectively. The current projected Plant Vogtle capacity payments are:

	Capacity Payments
	(in millions)
2006	$ 53
2007	52
2008	54
2009	54
2010	54
2011 and thereafter	261
Total	$528

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 at the time of the disallowance was written off.

The Company has entered into other various long-term commitments for the purchase of electricity. Estimated total long-term obligations under these

commitments at December 31, 2005 were as follows:

	Commitments	
	Affiliated	Non-Affiliated
	(in millions)	
2006	$205	$85
2007	205	86
2008	205	87
2009	205	68
2010	112	66
2011 and thereafter	455	278
Total	$1,387	$670

Operating Leases

The Company has entered into various operating leases with various terms and expiration dates. Rental expenses related to these operating leases totaled $38 million for 2005, $38 million for 2004, and $36 million for 2003.

At December 31, 2005, estimated minimum lease payments for these noncancelable operating leases were as follows:

	Minimum Lease Payments		
	Rail Cars	Other	Total
	(in millions)		
2006	$ 17	$ 17	$ 34
2007	17	14	31
2008	16	11	27
2009	15	9	24
2010	14	6	20
2011 and thereafter	48	10	58
Total	$127	$67	$194

In addition to the rental commitments above, the Company has obligations upon expiration of certain rail car leases with respect to the residual value of the leased property. These leases expire in 2011 and the Company's maximum obligation is $68 million. 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 rail car lease obligations is shared with the joint owners of plants Scherer and Wansley. Rental expenses related to the rail car leases are fully recoverable through the fuel cost recovery clause as ordered by the Georgia PSC.

Guarantees

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. Alabama Power has also guaranteed $50 million in senior notes issued by SEGCO. The Company has agreed to reimburse Alabama Power for the pro rata portion of such obligations corresponding to the Company'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.

8. STOCK OPTION PLAN

Southern Company provides non-qualified stock options to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2005, 1,551 current and former employees of the Company participated in the stock option plan. The maximum number of shares of Southern Company common stock that may be issued under this plan may not exceed 55 million. The prices of options granted to date have been at the fair market value of the shares on the dates of grant. Options granted to date become exercisable pro rata over a maximum period of three years from the date of grant. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the stock option plan. Activity from 2003 to 2005 for the options granted

to the Company's employees under the stock option plan is summarized below:

	Shares Subject To Option	Average Option Price Per Share
Balance at December 31, 2002	7,178,597	$19.73
Options granted	1,455,517	27.98
Options canceled	(54,860)	25.47
Options exercised	(1,428,273)	16.92
Balance at December 31, 2003	7,150,981	21.92
Options granted	1,434,915	29.50
Options canceled	(6,371)	25.99
Options exercised	(1,450,309)	18.25
Balance at December 31, 2004	**7,129,216**	**24.19**
Options granted	**1,427,618**	**32.71**
Options canceled	**(12,910)**	**23.75**
Options exercised	**(1,838,033)**	**21.23**
Balance at December 31, 2005	**6,705,891**	**$26.82**

Options exercisable:	
At December 31, 2003	3,956,234
At December 31, 2004	4,304,091
At December 31, 2005	**3,989,722**

The following table summarizes information about options outstanding at December 31, 2005:

	Dollar Price Range of Options		
	13-21	21-28	28-35
Outstanding:			
Shares (in thousands)	991	2,922	2,794
Average remaining life (in years)	4.2	6.0	8.5
Average exercise price	$17.25	$25.94	$31.13
Exercisable:			
Shares (in thousands)	991	2,496	503
Average exercise price	$17.25	$25.59	$29.75

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act, the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the Company's nuclear power plants. The Act provides funds up to $10.76 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 $101 million per incident for each licensed reactor it operates but not more than an aggregate of $15 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 $203 million per incident but not more than an aggregate of $30 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 up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. The Company purchases the maximum limit allowed by NEIL 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 NEIL policies would be $48 million.

Following the terrorist attacks of September 2001, both ANI and NEIL confirmed that terrorist acts against commercial nuclear power plants would, subject to the normal policy limits, be covered under their insurance. Both companies, however, revised their policy terms on

a prospective basis to include an industry aggregate for all "non-certified" terrorist acts i.e., acts that are not certified acts of terrorism pursuant to the Terrorism Risk Insurance Act of 2002, which was renewed in 2005. The aggregate for all NEIL policies, which applies to non-certified property claims stemming from terrorism within a 12-month duration, is $3.24 billion plus any amounts available through reinsurance or indemnity from an outside source. The non-certified ANI nuclear liability cap is a $300 million shared industry aggregate during the normal ANI policy period.

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

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

10. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2005 and 2004 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred Stock
		(in millions)	
March 2005	**$1,370**	**$286**	**$142**
June 2005	**1,459**	**311**	**158**
September 2005	**2,219**	**626**	**355**
December 2005	**1,586**	**165**	**60**
March 2004	$1,199	$285	$144
June 2004	1,353	322	156
September 2004	1,582	486	287
December 2004	1,237	166	71

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

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SELECTED FINANCIAL AND OPERATING DATA 2001-2005

Georgia Power Company 2005 Annual Report

	2005	2004	2003	2002	2001
Operating Revenues (in thousands)	$6,634,203	$5,370,808	$4,913,507	$4,822,460	$4,965,794
Net Income after Dividends on Preferred Stock (in thousands)	$714,999	$658,001	$630,577	$617,629	$610,335
Cash Dividends on Common Stock (in thousands)	$556,100	$565,500	$565,800	$542,900	$527,300
Return on Average Common Equity (percent)	14.15	13.95	14.05	13.99	14.12
Total Assets (in thousands)	$17,047,783	$15,822,338	$14,850,754	$14,342,656	$14,447,973
Gross Property Additions (in thousands)	$906,248	$1,126,064	$742,810	$883,968	$1,389,751
Capitalization (in thousands):					
Common stock equity	$5,214,535	$4,890,561	$4,540,211	$4,434,447	$4,397,485
Preferred stock	-	14,609	14,569	14,569	14,569
Mandatorily redeemable preferred securities	-	-	940,000	940,000	789,250
Long-term debt payable to affiliated trusts	969,073	969,073	-	-	-
Long-term debt	4,179,218	3,709,852	3,762,333	3,109,619	2,961,726
Total (excluding amounts due within one year)	$10,362,826	$9,584,095	$9,257,113	$8,498,635	$8,163,030
Capitalization Ratios (percent):					
Common stock equity	50.3	51.0	49.0	52.2	53.9
Preferred stock	-	0.2	0.2	0.2	0.2
Mandatorily redeemable preferred securities	-	-	10.2	11.1	9.6
Long-term debt payable to affiliated trusts	9.4	10.1	-	-	-
Long-term debt	40.3	38.7	40.6	36.5	36.3
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0
Security Ratings:					
Preferred Stock -					
Moody's	Baa1	Baa1	Baa1	Baa1	Baa1
Standard and Poor's	BBB+	BBB+	BBB+	BBB+	BBB+
Fitch	A	A	A	A	A
Unsecured Long-Term Debt -					
Moody's	A2	A2	A2	A2	A2
Standard and Poor's	A	A	A	A	A
Fitch	A+	A+	A+	A+	A+
Customers (year-end):					
Residential	1,832,520	1,801,426	1,768,662	1,734,430	1,698,407
Commercial	270,373	265,543	258,276	250,993	244,674
Industrial	8,206	7,676	7,899	8,240	8,046
Other	3,536	3,482	3,434	3,328	3,239
Total	2,114,635	2,078,127	2,038,271	1,996,991	1,954,366
Employees (year-end)	8,713	8,731	8,714	8,837	9,048

N/A = Not Applicable.

SELECTED FINANCIAL AND OPERATING DATA 2001-2005 (continued)
Georgia Power Company 2005 Annual Report

	2005	2004	2003	2002	2001
Operating Revenues (in thousands):					
Residential	$ 2,024,204	$1,736,072	$1,583,082	$1,600,438	$1,507,031
Commercial	2,206,252	1,812,096	1,661,054	1,631,130	1,682,918
Industrial	1,351,731	1,172,936	1,012,267	1,004,288	1,106,420
Other	60,625	55,881	53,569	52,241	52,943
Total retail	5,642,812	4,776,985	4,309,972	4,288,097	4,349,312
Sales for resale - non-affiliates	519,673	246,545	259,376	270,678	366,085
Sales for resale - affiliates	264,989	166,245	174,855	98,323	99,411
Total revenues from sales of electricity	6,427,474	5,189,775	4,744,203	4,657,098	4,814,808
Other revenues	206,729	181,033	169,304	165,362	150,986
Total	$6,634,203	$5,370,808	$4,913,507	$4,822,460	$4,965,794
Kilowatt-Hour Sales (in thousands):					
Residential	23,585,115	22,930,372	21,778,582	22,144,559	20,119,080
Commercial	29,768,402	28,014,357	26,940,572	26,954,922	26,493,255
Industrial	25,027,371	26,357,271	25,703,421	25,739,785	25,349,477
Other	601,330	602,202	595,742	593,202	583,007
Total retail	78,982,218	77,904,202	75,018,317	75,432,468	72,544,819
Sales for resale - non-affiliates	11,234,527	5,969,983	8,835,804	8,069,375	8,110,096
Sales for resale - affiliates	4,854,914	4,782,873	5,844,196	3,962,559	3,133,485
Total	95,071,659	88,657,058	89,698,317	87,464,402	83,788,400
Average Revenue Per Kilowatt-Hour (cents):					
Residential	8.58	7.57	7.27	7.23	7.49
Commercial	7.41	6.47	6.17	6.05	6.35
Industrial	5.40	4.45	3.94	3.90	4.36
Total retail	7.14	6.13	5.75	5.68	6.00
Sales for resale	4.88	3.84	2.96	3.07	4.14
Total sales	6.76	5.85	5.29	5.32	5.75
Residential Average Annual Kilowatt-Hour Use Per Customer	12,974	12,838	12,421	12,867	11,933
Residential Average Annual Revenue Per Customer	$1,113	$972	$903	$930	$894
Plant Nameplate Capacity Ratings (year-end) (megawatts)	15,097	13,978	13,980	14,059	14,474
Maximum Peak-Hour Demand (megawatts):					
Winter	13,501	12,208	13,153	11,873	11,977
Summer	15,953	15,180	14,826	14,597	14,294
Annual Load Factor (percent)	59.7	61.5	61.0	60.4	61.7
Plant Availability (percent):					
Fossil-steam	90.7	90.3	87.6	80.9	88.5
Nuclear	89.3	94.8	94.2	88.8	94.4
Source of Energy Supply (percent):					
Coal	60.8	57.9	58.6	59.5	58.5
Nuclear	15.1	17.3	16.8	16.2	18.1
Hydro	1.9	1.5	2.1	0.9	1.1
Oil and gas	2.9	0.1	0.3	0.3	0.4
Purchased power -					
From non-affiliates	5.7	7.0	7.5	6.3	7.8
From affiliates	13.6	16.2	14.7	16.8	14.1
Total	100.0	100.0	100.0	100.0	100.0

DIRECTORS AND OFFICERS
Georgia Power Company 2005 Annual Report

Directors

Juanita Powell Baranco
Executive Vice President
Baranco Acura
(Resigned effective 2/21/2006)

Gus H. Bell, III – *Nominee*
Chairman, President and Chief Executive Officer
Hussey, Gay, Bell and DeYoung - A Bell Company

Robert L. Brown, Jr.
President and Chief Executive Officer
R. L. Brown & Associates, Inc.

Ronald D. Brown
President and Chief Executive Officer
Atlanta Life Financial Group

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

Michael D. Garrett
President and Chief Executive Officer
Georgia Power Company

David M. Ratcliffe
President and Chief Executive Officer
The Southern Company

D. Gary Thompson
Retired from
Wachovia Corporation

Richard W. Ussery
Retired from
Total System Services (TSYS)

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

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

Officers

Michael D. Garrett
President and Chief Executive Officer
Georgia Power Company

William C. Archer, III
Executive Vice President
External Affairs
(Retirement effective 3/19/2006)

Mickey A. Brown
Executive Vice President
Customer Service Organization

Cliff S. Thrasher
Executive Vice President, Chief Financial Officer
and Treasurer

Christopher C. Womack
Executive Vice President (Effective 3/11/2006)
External Affairs

Judy M. Anderson
Senior Vice President
Charitable Giving

Richard L. Holmes
Senior Vice President
Metro Region

E. Lamont Houston
Senior Vice President (Effective 1/14/2006)
Customer Service and Sales

Douglas E. Jones
Senior Vice President (Effective 3/11/2006)
Fossil and Hydro Generation

James H. Miller III
Senior Vice President and
General Counsel

Leslie R. Sibert
Vice President
Transmission

Gene L. Ussery
Vice President
Distribution

DIRECTORS AND OFFICERS

Georgia Power Company 2005 Annual Report

Michael K. Anderson
Vice President (Effective 1/14/2006)
Corporate Services

W. Craig Barrs
Vice President

Robert A. Bell
Vice President (Effective 2/15/2006)
Human Resources

Rebecca A. Blalock
Vice President
Information Technology

P. Mike Clanton
Vice President (Effective 1/14/2006)
Customer Service

Ann P. Daiss
Vice President, Comptroller and
Chief Accounting Officer (Effective 3/11/2006)

Walter Dukes
Region Vice President
East

A. Bryan Fletcher
Vice President
Supply Chain Management

J. Kevin Fletcher
Vice President
Community and Economic Development

Jeff G. Franklin
Region Vice President
Northwest

Oscar C. Harper IV
Vice President (Effective 2/11/2006)
Resource Planning and Nuclear Development

O. Ben Harris
Vice President
Land

W. Ron Hinson
Vice President, Comptroller and
Chief Accounting Officer (Resigned effective
3/11/2006)

Ed F. Holcombe
Vice President
Governmental and Regulatory Affairs

Charles H. Huling
Vice President
Environmental Affairs

Anne H. Kaiser
Vice President
Sales

Ellen N. Lindemann
Vice President (Resigned effective 2/1/2006)
Human Resources

Jacki W. Lowe
Region Vice President
West

Daniel M. Lowery
Corporate Secretary

Terri H. Lupo
Region Vice President
South

Frank J. McCloskey
Vice President
Diversity

Robert B. Morris
Assistant Comptroller and Assistant Secretary

James E. Sykes, Jr.
Region Vice President
Northeast

Mark K. Tate
Assistant Comptroller

Jeff L. Wallace
Vice President (Resigned effective 2/11/2006)
Planning and Utility Relations

Thomas J. Wicker
Region Vice President
Central

W. Tal Wright
Vice President
Corporate Communication

Wayne Boston
Assistant Secretary and
Assistant Treasurer

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

Profile
The Company produces and delivers electricity as an integrated utility to retail customers within the State of Georgia and to wholesale customers in the Southeast. The Company sells electricity to approximately 2.1 million customers within its service area of approximately 57,000 square miles. In 2005, retail energy sales accounted for 83 percent of the Company's total sales of 95.1 billion kilowatt-hours.

The Company is a wholly owned subsidiary of The Southern Company, which is the parent company of five retail operating companies and a wholesale generation subsidiary, as well as other direct and indirect subsidiaries. There is no established public trading market for the Company's common stock.

Trustee, Registrar and Interest Paying Agent
All series of Senior Notes and Trust Preferred Securities
JPMorgan Chase Bank, N.A.
Institutional Trust Services
4 New York Plaza, 15th Floor
New York, NY 10004

Number of Preferred Shareholders of record as of December 31, 2005, was 1,003.

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

Georgia Power Company
241 Ralph McGill Boulevard, N.E.
Atlanta, GA 30308-3374
(404) 506-6526

Auditors
Deloitte & Touche LLP
Suite 1500
191 Peachtree Street, N.E.
Atlanta, GA 30303

Legal Counsel
Troutman Sanders LLP
600 Peachtree Street, N.E.
Suite 5200
Atlanta, GA 30308

GEORGIA POWER
A SOUTHERN COMPANY

July 28, 2006

Docket Nos.: 50-321 50-424
50-366 50-425
72-36

NL-06-1486

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
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 2005.

2. A set of quarterly financial statements for the period ending June 30, 2006.

3. A one year projected Cash Flows Statement for period January 1, 2007, through December 31, 2007.

Should you have any questions in connection with our response, please contact me at (404) 506-7952 or Jan Miller at (404) 506-6690. This letter contains no NRC commitments.

Sincerely,

Robert A. Aubuchon

Enclosures

cc: Southern Nuclear Operating Company
Mr. J. T. Gasser, Executive Vice President
Mr. L. M. Stinson, Vice President, Plant Hatch
Mr. D. E. Grissette, Vice President, Plant Vogtle
Mr. D. R. Madison, General Manager – Plant Hatch
Mr. T. E. Tynan, General Manager – Plant Vogtle
RType: CHA02.004; CVC7000

U. S. Nuclear Regulatory Commission
Dr. W. D. Travers, Regional Administrator
Mr. C. Gratton, NRR Project Manager – Hatch
Mr. C. Gratton, NRR Project Manager – Vogtle
Mr. D. S. Simpkins, Senior Resident Inspector – Hatch
Mr. G. J. McCoy, Senior Resident Inspector – Vogtle

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2006	2005	2006	2005
OPERATING REVENUES:				
Retail sales	$1,420,762	$1,227,087	$2,687,718	$2,412,323
Sales for resale–				
Non-affiliates	132,557	126,000	265,921	238,852
Affiliates	85,674	54,743	120,616	80,374
Other revenues	59,745	51,358	111,932	98,069
Total operating revenues	1,698,738	1,459,188	3,186,187	2,829,618
OPERATING EXPENSES:				
Operation–				
Fuel	556,691	412,050	991,465	721,316
Purchased power–				
Non-affiliates	82,321	64,523	138,876	117,497
Affiliates	145,518	140,800	336,037	360,804
Other	226,256	223,471	444,976	425,550
Maintenance	119,876	123,575	239,176	240,225
Depreciation and amortization	117,590	124,999	235,447	248,099
Taxes other than income taxes	68,945	58,648	136,090	119,407
Total operating expenses	1,317,197	1,148,066	2,522,067	2,232,898
OPERATING INCOME	381,541	311,122	664,120	596,720
OTHER INCOME (EXPENSE):				
Allowance for equity funds used during construction	6,338	7,935	12,123	17,192
Interest income	199	31	515	502
Interest expense, net of amounts capitalized	(61,322)	(55,174)	(121,529)	(105,594)
Interest expense to affiliate trusts	(14,877)	(14,877)	(29,755)	(29,755)
Other income (expense), net	3,370	2,821	2,376	(21)
Total other income and (expense)	(66,292)	(59,264)	(136,270)	(117,676)
EARNINGS BEFORE INCOME TAXES	315,249	251,858	527,850	479,044
Income taxes	119,059	94,140	199,003	178,794
NET INCOME	196,190	157,718	328,847	300,250
DIVIDENDS ON PREFERRED STOCK	-	167	1,010	335
NET INCOME AFTER DIVIDENDS ON PREFERRED STOCK	$196,190	$157,551	$327,837	$299,915

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, 2006	At June 30, 2005
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$11,422	$9,294
Receivables --		
Customer accounts receivable	416,118	361,605
Unbilled revenues	176,184	168,392
Under recovered regulatory clause revenue	372,587	153,301
Other accounts and notes receivable	85,136	185,223
Affiliated companies	55,814	31,350
Accumulated provision for uncollectible accounts	(8,521)	(6,575)
Fossil fuel stock, at average cost	262,620	207,959
Materials and supplies, at average cost	352,866	286,446
Other	174,706	91,819
Total Current Assets	1,898,932	1,488,814
PROPERTY, PLANT AND EQUIPMENT:		
In service	19,957,393	19,327,416
Less accumulated provision for depreciation	7,775,166	7,392,744
	12,182,227	11,934,672
Nuclear fuel, at amortized cost	148,604	129,567
Construction work in progress	599,874	443,904
Total Property, Plant and Equipment	12,930,705	12,508,143
OTHER PROPERTY AND INVESTMENTS:		
Equity investments in unconsolidated subsidiaries	68,470	65,949
Nuclear decommissioning trusts	499,868	466,656
Other	70,800	64,472
Total Other Property and Investments	639,138	597,077
DEFERRED CHARGES AND OTHER ASSETS:		
Deferred charges related to income taxes	497,775	506,259
Prepaid pension costs	487,462	460,865
Unamortized debt issuance expense	84,515	88,638
Unamortized loss on reacquired debt	165,650	172,961
Deferred under recovered regulatory clause revenues	477,611	362,692
Other	255,106	170,698
Total Deferred Charges and Other Assets	1,968,119	1,762,113
TOTAL ASSETS	$17,436,894	$16,356,147

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

	At June 30, 2006	At June 30, 2005
LIABILITIES AND STOCKHOLDER'S EQUITY		
CURRENT LIABILITIES:		
Securities due within one year	$2,822	$402,603
Notes payable	657,559	379,902
Accounts payable --		
Affiliated companies	207,585	157,765
Other	292,313	248,786
Customer deposits	140,292	122,446
Taxes accrued		
Income taxes	313,302	183,985
Other	146,254	115,596
Interest accrued	74,533	78,595
Vacation pay accrued	45,692	44,179
Other	210,770	186,640
Total Current Liabilities	2,091,122	1,920,497
LONG-TERM DEBT	4,177,916	3,931,825
LONG-TERM DEBT PAYABLE TO AFFILIATED TRUSTS	969,073	969,073
DEFERRED CREDITS AND OTHER LIABILITIES:		
Accumulated deferred income taxes	2,693,006	2,598,783
Deferred credits related to income taxes	153,196	164,588
Accumulated deferred investment tax credits	281,581	293,872
Employee benefits provisions	379,656	346,916
Asset retirement obligations	647,003	520,298
Other	548,023	581,077
Total Deferred Credits and Other Liabilities	4,702,465	4,505,534
PREFERRED STOCK	-	14,609
COMMON STOCKHOLDER'S EQUITY:		
Common stock	344,250	344,250
Paid-in capital	2,880,563	2,589,121
Retained earnings	2,288,285	2,124,641
Accumulated other comprehensive income	(16,780)	(43,403)
Total Common Stockholder's Equity	5,496,318	5,014,609
TOTAL LIABILITIES AND STOCKHOLDER'S EQUITY	$17,436,894	$16,356,147

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

	FOR THE SIX MONTHS ENDED JUNE 2006	2005
OPERATING ACTIVITIES:		
Net income	$328,847	$300,250
Adjustments to reconcile net income to net cash provided by operating activities --		
Depreciation and amortization	276,048	292,447
Deferred income taxes and investment tax credits, net	13,433	89,724
Deferred expenses - affiliated	18,717	20,302
Allowance for funds used during construction	(12,123)	(17,192)
Pension, postretirement, and other employee benefits	(1,225)	5,318
Stock option expense	4,330	-
Other, net	8,729	(1,058)
Changes in certain current assets and liabilities --		
Receivables, net	(89,773)	(247,991)
Fossil fuel stock	(80,881)	(23,692)
Materials and supplies	(28,885)	(16,024)
Other current assets	49,999	14,055
Accounts payable	(128,890)	(59,236)
Taxes accrued	38,209	43,098
Other current liabilities	(76,833)	(42,595)
NET CASH PROVIDED FROM OPERATING ACTIVITIES	319,702	357,406
INVESTING ACTIVITIES:		
Gross property additions	(448,857)	(381,191)
Nuclear decommissioning trust fund purchases	(241,021)	(205,261)
Nuclear decommissioning trust fund sales	234,141	196,562
Cost of removal net of salvage	(10,658)	(10,359)
Other	(9,099)	(33,274)
NET CASH USED FOR INVESTING ACTIVITIES	(475,494)	(433,523)
FINANCING ACTIVITIES:		
Increase (decrease) in notes payable, net	389,817	171,669
Proceeds --		
Senior notes	-	375,000
Pollution control bonds	10,125	185,000
Capital contributions from parent company	232,328	100,000
Gross excess tax benefit of stock options	611	-
Redemptions --		
Pollution control bonds	(10,125)	(85,000)
Senior notes	(150,000)	(300,000)
Preferred stock	(14,569)	
Special deposits - redemption funds	-	(100,000)
Payment of preferred stock dividends	(12)	(211)
Payment of common stock dividends	(301,250)	(278,050)
Other	(347)	(16,494)
NET CASH PROVIDED FROM FINANCING ACTIVITIES	156,578	51,914
NET CHANGE IN CASH AND CASH EQUIVALENTS	786	(24,203)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	10,636	33,497
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$11,422	$9,294

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

GEORGIA POWER COMPANY
PROJECTED STATEMENT OF CASH FLOWS
2007 FORECAST
(Stated in Thousands of Dollars)

	2007 FORECAST
OPERATING ACTIVITIES	
Net income before preferred dividends	$831,346
Principal noncash items-	
Depreciation and amortization	622,394
Deferred income taxes, net	(26,943)
Allowance for equity funds used during construction	(71,263)
Pension, postretirement and other employee benefits	(16,032)
Other, net	230,590
Change in current assets & liabilities-	
Receivables	(36,755)
Inventories	10,331
Accounts payable	9,114
Other current assets and liabilities	95,611
NET CASH PROVIDED FROM OPERATING ACTIVITIES	1,648,393
INVESTING ACTIVITIES	
Gross property additions	(1,485,481)
Cost of removal, net of salvage	(34,695)
Allowance for equity funds used during construction	71,263
Other property and investments	(6,514)
NET CASH USED FOR INVESTING ACTIVITIES	(1,455,427)
FINANCING ACTIVITIES	
Increase in notes payable, net	(8,860)
Proceeds -	
Senior notes	675,000
Preferred stock	300,000
Capital contributions from parent company	126,619
Redemptions -	
Senior notes	(300,000)
Trust preferred securities	(300,000)
Capitalized leases	(2,550)
Stock Option Expense	12,399
Payment of preferred stock dividends	(3,370)
Payment of common stock dividends	(678,100)
Other	(13,702)
NET CASH USED FOR FINANCING ACTIVITIES	(192,564)
NET INC (DEC) IN CASH AND TEMPORARY CASH INVESTMENTS	$402
CASH AND TEMPORARY CASH INVESTMENTS AT BEG OF PERIOD	$15,750
CASH AND TEMPORARY CASH INVESTMENTS AT END OF PERIOD	$16,152

2005 *Annual Report*

GEORGIA POWER COMPANY

GEORGIA POWER

A SOUTHERN COMPANY

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Georgia Power Company 2005 Annual Report

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SUMMARY

	2005	2004	Percent Change
Financial Highlights *(in millions):*			
Operating revenues	**$6,634**	$5,371	23.5
Operating expenses	**$5,246**	$4,112	27.6
Net income after dividends on preferred stock	**$715**	$658	8.7
Operating Data:			
Kilowatt-hour sales *(in millions):*			
Retail	**78,982**	77,904	1.4
Sales for resale - non-affiliates	**11,235**	5,970	88.2
Sales for resale - affiliates	**4,855**	4,783	1.5
Total	**95,072**	88,657	7.2
Customers served at year-end *(in thousands)*	**2,115**	2,078	1.8
Peak-hour demand *(in megawatts)*	**15,953**	15,180	5.1
Capitalization Ratios *(percent):*			
Common stock equity	**50.3**	51.0	
Preferred stock	-	0.2	
Long-term debt payable to affiliated trusts	**9.4**	10.1	
Long-term debt	**40.3**	38.7	
Return on Average Common Equity *(percent)*	**14.15**	13.95	
Ratio of Earnings to Fixed Charges *(times)*	**4.92**	5.11	

LETTER TO INVESTORS
Georgia Power 2005 Annual Report

Georgia Power employees' extraordinary response after Hurricane Katrina and other storms hit the Gulf Coast last year is just one of the highlights in what was a remarkable year for the company.

Whether we're responding to storms in our own back yard or to the needs of fellow Southern Company employees and customers, it's extensive pre-planning and excellent execution that makes us so successful – it really is what we do best.

That's why we were honored when the Edison Electric Institute recognized us with its Emergency Assistance Award for the outstanding assistance we provided other utilities recovering last year from hurricanes Katrina, Rita and Wilma.

Our financial results mirror our operational success. With operating revenues of $6.6 billion, Georgia Power's 2005 earnings totaled $715 million, a $57 million, or 8.7 percent, increase from 2004. We earned a 14.15 percent total company return on average common equity during 2005. Georgia Power had net plant in service of $12.0 billion at the end of 2005, with total assets of $17.0 billion.

In 2005, we announced plans to merge one of our sister companies into Georgia Power; we made significant progress on the environmental front; and we overhauled our organizational structure to bring us even closer to our customers.

Late last year, the boards of directors of Southern Company, Savannah Electric and Georgia Power approved a plan to merge Savannah Electric into Georgia Power. This move should result in operational efficiencies and cost savings for Georgia Power.

Savannah Electric customers also are expected to benefit from Georgia Power's more diverse and cost-efficient generating fleet. We anticipate completing the merger by July 2006.

We continued our efforts last year to reduce the environmental impact of our operations by:

- Turning on selective catalytic reduction systems at plants Bowen, Hammond and Wansley. This is expected to reduce the company's emissions of nitrogen oxides and, therefore, its contribution to metro Atlanta's ozone from 15 percent to 6 percent.

- Filing applications for four more scrubbers – two for Plant Wansley and two additional scrubbers for Plant Bowen. Two scrubbers are already under construction at Plant Bowen. Not only will the scrubbers, which remove sulfur dioxide (SO_2) from power plant emissions, reduce SO_2 emissions on each of these generating units by as much as 95 percent, but they also will reduce emissions of fine particulates and mercury. This is important because the Environmental Protection Agency issued its first mercury rule last year requiring significant reductions in mercury emissions from power plants.

- Working closely with DeKalb County in metro Atlanta, which approved the development of a landfill gas generation plant and a 10-year contract to sell the energy to Georgia Power for our voluntary Green Energy program.

In the past 10 years, we have invested $1 billion in environmental controls, and we'll continue to invest in environmental improvement technologies. In fact, over the next five years, Georgia Power's additional environmental investment is expected to total at least $2.4 billion.

In 2005, we also implemented a new organizational structure that moves key company leaders closer to our customers, employees and the communities we serve. We now have officer positions in major cities around the state, including Athens, Augusta, Columbus, Macon, Rome, Valdosta and, following the merger, Savannah.

Our new structure allows us to enhance efficiencies and operate consistently around the state while providing multiple cross-company leadership development opportunities within Southern Company – a key priority as we work to further develop the diversity and strength of our management ranks.

We believe improving diversity in every facet of our business is, simply put, good for business. That's why last year, for example, we launched a Hispanic Resources Web site, a one-stop shop for information to assist Spanish-speaking customers.

After all our hard work, it's nice to be recognized for our success. *Profiles in Diversity Journal* named Georgia Power to its top-10 list of diversity innovation award winners. We also were one of the Fortune 500 companies recognized as the nation's "Best Workplaces for Commuters," in large part because of SmartRide, our company commuter program that has become more popular than ever because of rising fuel prices. *Site Selection* magazine also recognized us as one of the best company's in North America for economic development.

We're especially proud of our linemen, who really shined at the International Lineman's Rodeo last year in Kansas City, winning first place in the overall, overall apprentice, investor-owned utility and senior divisions, along with a handful of individual event awards.

Continued economic vitality in Georgia helped boost electricity sales and was a key contributor to our strong financial results last year. Businesses and individuals were drawn to the state, increasing the number of customers Georgia Power serves to 2.1 million in 2005, a 1.8 percent increase from the previous year. Our retail sales of electricity climbed 1.4 percent in 2005.

It's clear to me that the work our employees do day in and day out and their commitment to the company are what make us successful – they are our greatest asset.

The changes we made and initiatives we launched last year will help ensure that we continue doing what's best for our employees, customers and communities – that we live up to our motto of being a "Citizen Wherever We Serve" – as we work to meet the state's growing demand for energy.

Sincerely,

Michael D. Garrett
April 17, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Georgia Power Company:

We have audited the accompanying balance sheets and statements of capitalization of Georgia Power Company (the "Company") (a wholly owned subsidiary of Southern Company) as of December 31, 2005 and 2004, 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, 2005. 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 the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements (pages 25 to 57) present fairly, in all material respects, the financial position of Georgia Power Company at December 31, 2005 and 2004, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
February 27, 2006

OVERVIEW

Business Activities

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

Many factors affect the opportunities, challenges, and risks of the Company's primary business of selling electricity. These factors include the ability to maintain a stable regulatory environment, to achieve energy sales growth while containing costs, and to recover rising costs. These costs include those related to growing demand, increasingly stringent environmental standards, and fuel prices. In December 2004, the Company completed a major retail rate proceeding that is expected to provide earnings stability (2004 Retail Rate Plan). This regulatory action also enables the recovery of substantial capital investments to facilitate the continued reliability of the transmission and distribution network and continued environmental improvements at the generating plants. Appropriately balancing environmental expenditures with customer prices will continue to challenge the Company for the foreseeable future. The Company expects further rate proceedings in 2006 to address fuel cost recovery due to higher than expected fuel costs for coal and natural gas.

On December 13, 2005, the Company and Savannah Electric and Power Company (Savannah Electric) entered into a merger agreement, under which Savannah Electric will merge into the Company, with the Company continuing as the surviving corporation (the Merger). The Merger must be approved by Savannah Electric's preferred shareholders and is subject to receipt of certain regulatory approvals from the Federal Energy Regulatory Commission (FERC), the Georgia Public Service Commission (PSC), and the Federal Communications Commission. Pending regulatory approvals, the Merger is expected to be completed by July 2006. See FUTURE EARNINGS POTENTIAL – "Merger" and Note 3 to the financial statements under "Retail Regulatory Matters – Merger" for additional information.

Key Performance Indicators

In striving to maximize shareholder value while providing low-cost energy to more than two million customers, the Company continues to focus on several key indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income. The Company's financial success is directly tied to the satisfaction of its customers. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance, expected weather conditions, and expected capital expenditures. Net income is the primary component of the Company's contribution to Southern Company's earnings per share goal.

The Company's 2005 results compared to its targets for some of these indicators are reflected in the following chart.

Key Performance Indicator	2005 Target Performance	**2005 Actual Performance**
Customer Satisfaction	Top quartile in customer surveys	**Top quartile**
Peak Season EFOR	2.75% or less	**1.42%**
Net Income	$678 million	**$715 million**

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The strong financial performance achieved in 2005 reflects the focus that management places on these indicators, as well as the commitment shown by the employees in achieving or exceeding management's expectations.

Earnings

The Company's 2005 earnings totaled $715 million representing a $57 million (8.7 percent) increase over 2004. Operating income increased in 2005 due to higher base retail revenues resulting from the retail rate increase

effective January 1, 2005 and more favorable weather, as well as higher wholesale revenues resulting from new contracts effective January 1, 2005, partially offset by increased non-fuel operating expenses. The Company's 2004 earnings totaled $658 million representing a $27 million (4.3 percent) increase over 2003. Operating income increased in 2004 due to higher base retail revenues attributable to more favorable weather and customer growth during the year, partially offset by higher non-fuel operating expenses. In addition, lower depreciation and amortization expense resulting from a Georgia PSC three-year retail rate plan approved in 2001 (2001 Retail Rate Plan) significantly offset increased purchased power capacity expenses. The Company's 2003 earnings totaled $631 million, representing a $13 million (2.1 percent) increase over 2002 despite lower base retail revenues resulting from the extremely mild summer weather. Higher wholesale revenues and lower non-fuel operating expenses contributed to the 2003 increase.

RESULTS OF OPERATIONS

A condensed income statement for the Company is as follows:

	Amount	Increase (Decrease) From Prior Year		
	2005	**2005**	2004	2003
		(in millions)		
Operating revenues	**$6,634**	**$1,263**	$457	$ 92
Fuel	**1,831**	**598**	128	101
Purchased power	**1,170**	**194**	200	92
Other operation and maintenance	**1,481**	**81**	153	(78)
Depreciation and amortization	**504**	**229**	(74)	(54)
Taxes other than income taxes	**260**	**32**	15	11
Total operating expenses	**5,246**	**1,134**	422	72
Operating income	**1,388**	**129**	35	20
Total other income and (expense)	**(241)**	**(20)**	5	2
Income taxes	**431**	**52**	13	9
Net income	**716**	**57**	27	13
Dividends on preferred stock	**1**	**-**	-	-
Net income after dividends on preferred stock	**$ 715**	**$ 57**	$ 27	$ 13

Revenues

Operating revenues in 2005, 2004, and 2003 and the percent of change from the prior year are as follows:

	Amount		
	2005	2004	2003
		(in millions)	
Retail – prior year	**$4,777**	$4,310	$4,288
Change in -			
Base rates	**195**	-	-
Sales growth	**135**	151	30
Weather	**21**	32	(66)
Fuel cost recovery and other	**515**	284	58
Retail – current year	**$5,643**	4,777	4,310
Sales for resale -			
Non-affiliates	**519**	247	260
Affiliates	**265**	166	175
Total sales for resale	**784**	413	435
Other operating revenues	**207**	181	169
Total operating revenues	**$6,634**	$5,371	$4,914
Percent change	**23.5%**	9.3%	1.9%

Retail base revenues of $3.6 billion in 2005 increased by $351 million (10.9 percent) from 2004 primarily due to the retail rate increase effective January 1, 2005, sustained economic strength, customer growth, more favorable weather, and generally higher prices to large business customers. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information. Retail base revenues of $3.2 billion in 2004 increased by $183 million (6.0 percent) from 2003 primarily due to an improved economy, customer growth, generally higher prices to the Company's large business customers, and more favorable weather. Retail base revenues of $3 billion in 2003 decreased by $36 million (1.2 percent) from 2002 primarily due to extremely mild summer temperatures and the sluggish economy.

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. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information.

Wholesale revenues from sales to non-affiliated utilities were:

	2005	2004	2003
		(in millions)	
Unit power sales --			
Capacity	$ 33	$ 31	$ 34
Energy	31	33	31
Other power sales --			
Capacity and other	155	75	93
Energy	300	108	102
Total	$519	$247	$260

Revenues from unit power sales contracts remained relatively constant in 2005 and 2004. Revenues from unit power sales contracts decreased slightly in 2003 due to decreased energy sales. Revenues from other non-affiliated sales increased $272 million (148.6 percent) in 2005 and decreased $12 million (6.2 percent) and $8 million (3.9 percent) in 2004 and 2003, respectively. The increase in 2005 is due to new contracts with thirty electric membership corporation customers that went into effect in January 2005 which increased the demand for energy. The capacity component of these transactions increased $73.2 million in 2005 over 2004.

Revenues from sales to affiliated companies within the Southern Company electric system, as well as purchases of energy, will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliated sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the FERC. In 2005, kilowatt-hour (KWH) energy sales to affiliates increased 1.5 percent due to higher demand, while the increase in associated revenues was 59.4 percent due to higher fuel prices. In 2004, KWH energy sales to affiliates decreased 18.2 percent due to lower demand. However, the decline in associated revenues was only 4.9 percent due to higher fuel prices. In 2003, KWH energy sales to affiliates increased 47.5 percent due to the combination of increased demand by Southern Power to meet contractual obligations and the availability of power due to milder-than-normal weather in the Company's service territory. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost.

Other operating revenues increased $25.7 million (14.2 percent) in 2005 from 2004 primarily due to higher transmission revenues of $16 million related to work performed for the other owners of the integrated transmission system in the State of Georgia and higher revenues under the open access tariff agreement, higher outdoor lighting revenues of $5.4 million, and higher customer fees that went into effect in January 2005 of $5.9 million. Other operating revenues increased $11.7 million (6.9 percent) in 2004 over 2003 primarily due to higher revenues from outdoor lighting of $4.2 million and pole attachment rentals of $4.9 million and higher gains on sales of emission allowances of $2 million. Other operating revenues increased $4 million (2.4 percent) in 2003 from the prior year primarily due to an increase in the open access transmission tariff rate, which increased revenues $7 million, and higher revenues from increased customer demand for outdoor lighting services of $4 million, partially offset by lower revenues from the rental of electric property of $4 million.

Energy Sales

KWH sales for 2005 and the percent change by year were as follows:

	KWH	Percent Change		
	2005	2005	2004	2003
	(in billions)			
Residential	23.6	2.9%	5.3%	(1.7)%
Commercial	29.8	6.3	4.0	(0.1)
Industrial	25.0	(5.0)	2.5	(0.1)
Other	0.6	(0.1)	1.1	0.4
Total retail	79.0	1.4	3.8	(0.5)
Sales for resale -				
Non-affiliates	11.2	88.2	(32.5)	9.5
Affiliates	4.9	1.5	(18.2)	47.5
Total sales for resale	16.1	49.6	(26.8)	22.0
Total sales	95.1	7.2	(1.2)	2.6

Residential KWH sales increased 2.9 percent in 2005 over 2004 due to more favorable weather, customer growth of 1.7 percent, and a 1.1 percent increase in the average energy consumption per customer. Commercial KWH sales increased 6.3 percent due to more favorable weather, sustained economic strength, customer growth of 1.8 percent, and a reclassification of customers from industrial to commercial to be consistent with the rate structure approved by the Georgia PSC when compared

to 2004. Industrial sales decreased 5.0 percent primarily due to this reclassification of customers.

Residential KWH sales increased 5.3 percent in 2004 from 2003 due to more favorable weather and a 1.9 percent increase in residential customers. Commercial KWH sales increased 4.0 percent in 2004 due to an improved economy and a 2.8 percent increase in commercial customers. Industrial sales increased 2.5 percent in 2004 due to the improved economy.

Residential KWH sales decreased 1.7 percent in 2003 from 2002 due to the effect of the milder summer weather, despite the 2.0 percent increase in residential customers. Commercial KWH sales in 2003 declined slightly due to the milder summer weather, while industrial KWH sales declined slightly due to the sluggish economy. Average retail sales growth assuming normal weather is expected to be 2.1 percent from 2006 to 2010.

Fuel and Purchased Power 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 generating units. The amount and sources of generation, the average cost of fuel per net KWH generated, and the average cost of purchased power per net KWH were as follows:

	2005	2004	2003
Total generation (billions of KWH)	**80.5**	71.5	73.1
Sources of generation (percent) --			
Coal	**75.3**	75.4	75.4
Nuclear	**18.6**	22.5	21.6
Hydro	**2.4**	2.0	2.7
Oil and gas	**3.7**	0.1	0.3
Average cost of fuel per net KWH generated (cents) --	**2.04**	1.55	1.46
Average cost of purchased power per net KWH (cents) --	**7.25**	5.17	4.03

Fuel expense increased 48.5 percent in 2005 from the prior year primarily due to an increase in the average cost of fuel, particularly natural gas, and a 12.3 percent increase in generation to meet higher demand. Fuel expense increased 11.6 percent in 2004 over 2003 primarily due to an increase in the average cost of coal and natural gas. Fuel expense increased 10.1 percent in 2003 over 2002 due to an increase in generation of 3.9 percent because of higher wholesale energy demands and a 2.8 percent higher average cost of fuel due to the higher prices of coal and natural gas in 2003.

Purchased power expense increased $194 million (19.9 percent) in 2005, $200 million (25.9 percent) in 2004, and $92 million (13.3 percent) in 2003. These increases are primarily the result of new purchased power agreements (PPAs) between the Company and Southern Power that went into effect in each of 2004, 2003, and 2002. Additional capacity expenses associated with these PPAs were $30 million, $65 million, and $75 million in 2005, 2004, and 2003, respectively. The increases in purchased power expenses also reflect the impact of the significant increases in fuel costs discussed previously.

A significant upward trend in the cost of coal and natural gas has emerged since 2003, and volatility in these markets is expected to continue. Increased coal prices have been influenced by a worldwide increase in demand as a result of rapid economic growth in China as well as by increases in mining costs. Higher natural gas prices in the United States are the result of increased demand and slightly lower gas supplies despite increased drilling activity. Natural gas supply interruptions, such as those caused by the 2005 and 2004 hurricanes, result in an immediate market response; however, the long-term impact of this price volatility may be reduced by imports of natural gas and liquefied natural gas. Fuel expenses generally do not affect net income, since they are offset by fuel revenues under the Company's fuel cost recovery provisions.

Other Operating Expenses

In 2005, other operations and maintenance expenses increased $81 million (5.8 percent). Maintenance for generating plant and transmission and distribution increased $23.5 million and $13.9 million, respectively, as a result of scheduled outages and, to a lesser extent, certain flexible projects planned for other periods. Increased employee benefit expense of $18.4 million related to pension and medical benefits and higher property insurance costs of $5.3 million resulting from storm damage also contributed to the increase. Customer

assistance expense and uncollectible account expense also increased an additional $9.3 million in 2005 over 2004, primarily as a result of promotional expenses related to an energy efficiency program and an increased number of customer bankruptcies, respectively. In 2004, other operations and maintenance expenses increased $153 million (12.3 percent) due to the timing of generating plant maintenance of $39 million and transmission and distribution maintenance of $39 million. Increased employee benefit expense of $30 million related to pension and medical benefits and higher workers compensation expense of $8 million also contributed to the increase. In 2003, other operations and maintenance expenses decreased $78 million (5.9 percent) due to the timing of generating plant maintenance of $46 million and transmission and distribution maintenance of $8 million and lower severance costs of $8 million.

Depreciation and amortization increased $229 million (83 percent) in 2005 over 2004 primarily due to the expiration at the end of 2004 of certain provisions of the Company's 2001 Retail Rate Plan. In accordance with the 2001 Retail Rate Plan, the Company amortized an accelerated cost recovery liability as a credit to amortization expense and recognized new Georgia PSC-certified purchased power costs in rates evenly over the three years ended December 31, 2004. This treatment resulted in a credit to amortization expense of $187.1 million in 2004 and a total decrease in depreciation and amortization of $74 million and $54 million in 2004 and 2003, respectively. See Note 3 to the financial statements under "Retail Regulatory Matters -- Rate Plans" for additional information.

Taxes other than income taxes increased $32 million (14.1 percent) primarily due to higher municipal gross receipts taxes of $18.1 million resulting from increased operating revenues and higher property taxes of $14.0 million. Taxes other than income taxes increased $15 million (7.0 percent) in 2004 due to higher municipal gross receipts taxes associated with increased operating revenues. Taxes other than income taxes increased $11 million (5.4 percent) in 2003 due mainly to a favorable true-up of state property tax valuations in 2002.

Other Income and (Expense)

Allowance for equity funds used during construction remained relatively constant in 2005 and increased $15.9 million in 2004, primarily due to the construction of the McIntosh combined cycle Units 10 and 11 which were placed in service in June 2005.

Interest income remained relatively constant in 2005. Interest income decreased $9 million in 2004 and increased $12 million in 2003 when compared to the prior year primarily due to interest on a favorable income tax settlement of $14.5 million in 2003.

Interest expense increased $38.8 million (21.3 percent) in 2005 from 2004 primarily due to the issuance of additional senior notes in 2005 and generally higher interest rates on variable rate debt and commercial paper. Interest expense remained relatively constant in 2004. Interest expense increased in 2003 primarily due to an increase in senior notes outstanding that was partially offset by a reduction in short-term debt outstanding. The Company refinanced or retired $635 million, $400 million, and $665 million of securities in 2005, 2004, and 2003, respectively. Interest capitalized increased in 2005 and 2004 due to the Plant McIntosh construction referenced above and decreased in 2003 due to the transfer of a project to Southern Power in 2002.

Other income and (expense), net increased $17.1 million in 2005 from 2004 primarily due to $14.2 million of additional gas hedge gains. Other income and (expense), net decreased in 2004 primarily due to the $13 million disallowance of Plant McIntosh construction costs in December 2004, partially offset by a $7.5 million decrease in donations and $3.4 million in increased income from a customer pricing program. See Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Hedging Program" and "Plant McIntosh Construction Project" for additional information.

Effects of Inflation

The Company is subject to rate regulation that is based on the recovery of historical costs. In addition, the income tax laws are based on historical costs. Therefore, inflation creates an economic loss because the Company is recovering its costs of investments in dollars that have less purchasing power. While the inflation rate has been relatively low in recent years, it continues to have an adverse effect on the Company because of the large investment in utility plant with long economic lives. Conventional accounting for historical cost does not recognize this economic loss nor the partially offsetting gain that arises through financing facilities with fixed-

money obligations such as long-term debt, preferred stock, and preferred securities. Any recognition of inflation by regulatory authorities is reflected in the rate of return allowed in the Company's approved electric rates.

FUTURE EARNINGS POTENTIAL

General

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

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability of the Company to maintain a stable regulatory environment that continues to allow for the recovery of all prudently incurred costs. Future earnings in the near term will depend, in part, upon growth in energy sales, which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth in the Company's service area.

Environmental Matters

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S District Court for the Northern District of Georgia against the Company and Alabama Power, alleging that the Company and Alabama Power had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws with respect to certain coal-fired generating facilities. Through subsequent amendments and other legal proceedings, the EPA added Savannah Electric as a defendant to the original action and filed a separate action against Alabama Power after it was dismissed from the original action. In these lawsuits, the EPA alleges that NSR violations occurred at eight coal-fired generating facilities, including the Company's Plants Bowen and Scherer. The civil action requests penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. On June 3, 2005, the U.S. District for the Northern District of Alabama issued a decision in favor of Alabama Power on two primary legal issues in the case; however, the decision does not resolve the case, nor does it address other legal issues associated with the EPA's allegations. In accordance with a separate court order, Alabama Power and the EPA are currently participating in mediation with respect to the EPA's claims. The action against the Company and Savannah Electric has been administratively closed since the spring of 2001, and none of the parties has sought to reopen the case. See Note 3 to the financial statements under "Environmental Matters - New Source Review Actions."

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $32,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in this matter could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

In December 2002 and October 2003, the EPA issued final revisions to its NSR regulations under the Clean Air Act. A coalition of states and environmental organizations filed petitions for review of these regulations. On June 24, 2005, the U.S. Court of Appeals for the District of Columbia Circuit upheld, in part, the EPA's December 2002 revisions to its NSR regulations, which included changes to the regulatory exclusions and

methods of calculating emissions increases. However, the court vacated portions of those revisions, including those addressing the exclusion of certain pollution control projects. The October 2003 revisions, which clarified the scope of the existing Routine Maintenance, Repair and Replacement exclusion, have been stayed by the Court of Appeals pending its review of the rules. On October 20, 2005, the EPA also published a proposed rule clarifying the test for determining when an emissions increase subject to the NSR requirements has occurred. The impact of these revisions and proposed rules will depend on adoption of the final rules by the EPA and the State of Georgia's implementation of such rules, as well as the outcome of any additional legal challenges, and, therefore, cannot be determined at this time.

Carbon Dioxide Litigation

In July 2004, attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed a complaint in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. A nearly identical complaint was filed by three environmental groups in the same court. The complaints allege that the companies' emissions of carbon dioxide, a greenhouse gas, contribute to global warming, which the plaintiffs assert is a public nuisance. Under common law public and private nuisance theories, the plaintiffs seek a judicial order (1) holding each defendant jointly and severally liable for creating, contributing to, and/or maintaining global warming and (2) requiring each of the defendants to cap its emissions of carbon dioxide and then reduce those emissions by a specified percentage each year for at least a decade. Plaintiffs have not, however, requested that damages be awarded in connection with their claims. Southern Company believes these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2005, the U.S. District Court for the Southern District of New York granted Southern Company's and the other defendants' motions to dismiss these cases. The plaintiffs filed an appeal to the U.S. Court of Appeals for the Second Circuit on October 19, 2005. The ultimate outcome of these matters cannot be determined at this time.

Plant Wansley Environmental Litigation

In December 2002, the Sierra Club, Physicians for Social Responsibility, Georgia Forestwatch, and one individual filed a civil suit in the U.S. District Court for the Northern District of Georgia against the Company for alleged violations of the Clean Air Act at four of the units at Plant Wansley. 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. The liability phase of the case has concluded with the court ruling in favor of the Company in part and the plaintiffs in part. In March 2005, the U.S. Court of Appeals for the Eleventh Circuit accepted the Company's petition for review of the district court's order, and oral arguments were held on January 24, 2006. The district court case has been administratively closed pending that appeal. If necessary, the district court will hold a separate trial which will address civil penalties and possible injunctive relief requested by the plaintiffs. The ultimate outcome of this matter cannot currently be determined; however, an adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require the payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

Environmental Statutes and Regulations

General

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. Applicable statutes 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 these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2005, the Company had invested approximately $1.2 billion in

capital projects to comply with these requirements, with annual costs of $117.4 million, $47.4 million, and $105.7 million for 2005, 2004, and 2003, respectively. Over the next decade, the Company expects that capital expenditures could exceed an additional $3.3 billion to assure compliance with existing and new regulations, including $410 million, $674.6 million, and $515.8 million for 2006, 2007, and 2008, respectively. Because the Company's compliance strategy is impacted by changes to existing environmental laws and regulations, the cost, availability, and existing inventory of emission allowances, and the Company's fuel mix, the ultimate outcome cannot be determined at this time. Environmental costs that are known and estimable at this time are included in capital expenditures discussed under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein.

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

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Through 2005, the Company had spent approximately $787.9 million in reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions and in monitoring emissions pursuant to the Clean Air Act. Additional controls have been announced and are currently being installed at several plants to further reduce SO_2 and NO_x emissions, maintain compliance with existing regulations, and to meet new requirements.

Approximately $699.8 million of these expenditures are related to reducing NO_x emissions pursuant to state and federal requirements in connection with the EPA's one-hour ozone standard and the 1998 regional NO_x reduction rules. Although the State of Georgia was originally included in the states subject to the regional NO_x rules, the EPA, in August 2005, stayed compliance with these requirements and initiated rulemakings to address issues raised in a petition for reconsideration filed by a coalition of Georgia industries. The impact of the 1998 regional NO_x reduction rules for Georgia will depend on the outcome of the petition for reconsideration and/or any subsequent development and approval of the State of Georgia's state implementation plan.

In 2005, the EPA revoked the one-hour ozone standard and published the final set of rules for implementation of the new, more stringent eight-hour ozone standard. Areas within the Company's service area that have been designated as nonattainment under the eight-hour ozone standard include Macon (Georgia) and a 20-county area within metropolitan Atlanta. State implementation plans, including new emission control regulations necessary to bring those areas into attainment are required for most areas by June 2007. These state implementation plans could require further reductions in NO_x emissions from power plants.

During 2005, the EPA's fine particulate matter "nonattainment" designations became effective for several areas within the Company's service area in Georgia, and the EPA proposed a rule for the implementation of the fine particulate matter standard. The EPA plans to finalize the proposed implementation rule in 2006. State plans for addressing the nonattainment designations are required by April 2008 and could require further reductions in SO_2 and NO_x emissions from power plants. The EPA has also published proposed revisions to lower the level of particulate matter currently allowed.

The EPA issued the final Clean Air Interstate Rule on March 10, 2005. This cap-and-trade rule addresses power plant SO_2 and NO_x emissions that were found to contribute to nonattainment of the eight-hour ozone and fine particulate matter standards in downwind states. Twenty-eight eastern states, including the State of Georgia, are subject to the requirements of the rule. The rule calls for additional reductions of NO_x and/or SO_2 to be achieved in two phases, 2009/2010 and 2015. These reductions will be accomplished by the installation of additional emission controls at the Company's coal-fired facilities or by the purchase of emission allowances from a cap-and-trade program.

The Clean Air Visibility Rule (formerly called the Regional Haze Rule) was finalized on July 6, 2005. The goal of this rule is to restore natural visibility conditions in certain areas (primarily national parks

and wilderness areas) by 2064. The rule involves the application of Best Available Retrofit Technology (BART) requirements and a review each decade, beginning in 2018, of progress toward the goal. BART requires that sources that contribute to visibility impairment implement additional emission reductions, if necessary, to make progress toward remedying current visibility concerns. For power plants, the Clean Air Visibility Rule allows states to determine that the Clean Air Interstate Rule satisfies BART requirements for SO_2 and NO_x. However, additional requirements could be imposed. By December 17, 2007, states must submit implementation plans that contain emission reduction strategies for implementing BART requirements and for achieving sufficient and reasonable progress toward the goal.

On March 15, 2005, the EPA announced the final Clean Air Mercury Rule, a cap-and-trade program for the reduction of mercury emissions from coal-fired power plants. The rule sets caps on mercury emissions to be implemented in two phases, 2010 and 2018, and provides for an emission allowance trading market. The Company anticipates that emission controls installed to achieve compliance with the Clean Air Interstate Rule and the eight-hour ozone and fine-particulate standards will also result in mercury emission reductions. However, the long-term capability of emission control equipment to reduce mercury emissions is still being evaluated, and the installation of additional control technologies may be required.

The impacts of the eight-hour ozone standard, the fine particulate matter nonattainment designations, the Clean Air Interstate Rule, the Clean Air Visibility Rule, and the Clear Air Mercury Rule on the Company, will depend on the development and implementation of rules at the state level. States implementing the Clean Air Mercury Rule and the Clear Air Interstate Rule, in particular, have the option not to participate in the national cap-and-trade programs and could require reductions greater than those mandated by the federal rules. Such impacts will also depend on resolution of pending legal challenges to the Clean Air Interstate Rule, the Clean Air Mercury Rule and a related petition from the State of North Carolina under section 126 of the Clean Air Act, also related to the interstate transport of air pollutants. Therefore, the full impacts of these regulations on the Company cannot be determined at this time. The Company has developed and continually updates a comprehensive environmental compliance strategy to comply with the continuing and new environmental requirements discussed above. As part of this strategy, the Company plans to install additional SO_2, NO_x, and mercury emission controls within the next several years to assure continued compliance with applicable air quality requirements.

Water Quality

In July 2004, the EPA published final rules under the Clean Water Act for the purpose of reducing impingement and entrainment of fish and fish larvae at power plants' cooling water intake structures. The new rules require baseline biological information and, perhaps, installation of fish protection technology near some intake structures at existing power plants.

The Company is installing cooling towers at additional facilities under the Clean Water Act to cool water prior to discharge. Near Atlanta, a cooling tower for one plant was completed in 2004 and two others are scheduled for completion in 2008. The total estimated cost of these projects is $173 million, with $85 million remaining to be spent. The Company is also conducting a study of the aquatic environment at another facility to determine if further thermal controls are necessary at that plant.

The full impact of these new rules will depend on the results of studies and analyses performed as part of the rules' implementation and the actual requirements established by the State of Georgia, and therefore, cannot be determined at this time

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and release 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 and monitor known sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Remediation" for additional information.

Under Georgia PSC ratemaking provisions, $22 million has been deferred in a regulatory liability account related to certain environmental insurance settlements. Under the 2004 Retail Rate Plan, this regulatory liability is being amortized as a credit to expense over a three-year period that began January 1, 2005. However, the Georgia PSC also approved an annual environmental accrual of $5.4 million. Environmental remediation expenditures are being charged against the resulting reserve as they are incurred. The annual accrual amount will be reviewed and adjusted in future regulatory proceedings.

Global Climate Issues

Domestic efforts to limit greenhouse gas emissions have been spurred by international discussions surrounding the Framework Convention on Climate Change, and specifically the Kyoto Protocol -- which proposes constraints on the emissions of greenhouse gases for a group of industrialized countries. The Bush Administration has not supported U.S. ratification of the Kyoto Protocol or other mandatory carbon dioxide reduction legislation; however, in 2002, it did announce a goal to reduce the greenhouse gas intensity of the U.S. – the ratio of greenhouse gas emissions to the value of U.S. economic output -- by 18 percent by 2012. A year later, the Department of Energy (DOE) announced the Climate VISION program to support this goal. Energy-intensive industries, including electricity generation, are the initial focus of this program. Southern Company is involved in the development of a voluntary electric utility sector climate change initiative in partnership with the government. In a memorandum of understanding signed in December 2004 with the DOE under Climate VISION, the utility sector pledged to reduce its greenhouse gas emissions rate by 3 percent to 5 percent by 2010-2012. The Company is continuing to evaluate future energy and emissions profiles relative to the Climate VISION program and is analyzing voluntary programs to support the industry initiative.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates at market-based prices. The Company also has FERC authority to make short-term opportunity sales at market rates. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in that proceeding. In February 2005, Southern Company submitted responsive information. In February 2006, the FERC suspended the proceeding. Any new market-based rate transactions in its retail service territory entered into after February 27, 2005 are subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. The impact of such sales through December 31, 2005 is not expected to exceed $4.9 million. The refund period covers 15 months. In the event that the FERC's default mitigation measures for entities that are found to have market power are ultimately applied, the Company may be required to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates. The final outcome of this matter will depend on the form in which the final methodology for assessing generation market power and mitigation rules may be ultimately adopted and cannot be determined at this time.

In addition, in May 2005, the FERC started an investigation to determine whether Southern Company satisfies the other three parts of the FERC's market-based rate analysis: transmission market power, barriers to entry, and affiliate abuse or reciprocal dealing. The FERC established a new refund period related to this expanded investigation. Any and all new market-based rate transactions both inside and outside Southern Company's retail service territory involving any Southern Company subsidiary, including the Company, will be subject to refund to the extent the FERC orders lower rates as a result of this new investigation, with the 15-month refund period beginning July 19, 2005. The impact of such sales through December 31, 2005 is not expected to exceed $10.9 million, of which $3.2 million relates to sales inside the retail service territory as discussed above. The FERC also directed that this expanded proceeding be held in abeyance pending the outcome of the proceeding on the IIC discussed below.

The Company believes that there is no meritorious basis for this proceeding and is vigorously defending itself in this matter. However, the final outcome of this

matter, including any remedies to be applied in the event of an adverse ruling in this proceeding, cannot now be determined.

Intercompany Interchange Contract

The Company's generation fleet in its retail service territory is operated under the IIC, as approved by the FERC. In May 2005, the FERC also initiated a new proceeding to examine (1) the provisions of the IIC among Alabama Power, the Company, Gulf Power, Mississippi Power, Savannah Electric, Southern Power, and Southern Company Services, Inc., as agent, under the terms of which the power pool of Southern Company is operated, and, in particular, the propriety of the continued inclusion of Southern Power as a party to the IIC, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining Southern Power as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of Southern Power, the FERC authorized Southern Power's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct. The FERC order directs that the administrative law judge who presided over the McIntosh PPA proceeding discussed herein under "PSC Matters – Plant McIntosh Construction Project", be assigned to preside over the hearing in this proceeding and that the testimony and exhibits presented in that proceeding be preserved to the extent appropriate. Hearings are scheduled for September 2006. Effective July 19, 2005, revenues from transactions under the IIC involving any Southern Company subsidiaries, including the Company, are subject to refund to the extent the FERC orders any changes to the IIC.

The Company believes that there is no meritorious basis for this proceeding and is vigorously defending itself in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in this proceeding, cannot now be determined.

Generation Interconnection Agreements

In July 2003, the FERC issued its final rule on the standardization of generation interconnection agreements and procedures (Order 2003). Order 2003 shifts much of the financial burden of new transmission investment from the generator to the transmission provider. The FERC has indicated that Order 2003, which was effective January 20, 2004, is to be applied prospectively to interconnection agreements. Subsidiaries of Tenaska, Inc., as counterparties to three previously executed interconnection agreements with subsidiaries of Southern Company, including the Company, have filed complaints at the FERC requesting that the FERC modify the agreements and that the Company refund a total of $7.9 million previously paid for interconnection facilities, with interest. The Company has opposed all such requests, and the proceedings are still pending. The impact of Order 2003 and its subsequent rehearings on the Company and the final results of these matters cannot be determined at this time.

Transmission

In December 1999, the FERC issued its final rule on Regional Transmission Organizations (RTOs). Since that time, there have been a number of additional proceedings at the FERC designed to encourage further voluntary formation of RTOs or to mandate their formation. However, at the current time, there are no active proceedings that would require the Company to participate in an RTO. Current FERC efforts that may potentially change the regulatory and/or operational structure of transmission include rules related to the standardization of generation interconnection, as well as an inquiry into, among other things, market power by vertically integrated utilities. See "Generation Interconnection Agreements" and "Market-Based Rate Authority" herein for additional information. The final outcome of these proceedings cannot now be determined. However, the Company's financial condition, results of operations, and cash flows could be adversely affected by future changes in the federal regulatory or operational structure of transmission.

PSC Matters

Merger

In connection with the Merger, the Company and Savannah Electric plan to establish a coastal regional organization for the Company that will be operating following completion of the Merger. Management expects that current Savannah Electric employees will fill most of the positions in the new regional organization.

While the Georgia PSC does not have specific approval authority over the merger of electric utilities, in January 2006, the Company and Savannah Electric filed an application with the Georgia PSC for certain approvals necessary to complete the Merger. In particular, the Company and Savannah Electric are seeking the approval of the Georgia PSC with respect to the following matters:

- the transfer of Savannah Electric's generating facilities and certification of the generating facilities as the Company's assets;
- amendments to the Company's Integrated Resource Plan to add the current Savannah Electric's customers and generating facilities;
- the transfer of Savannah Electric's assigned service territory to the Company;
- adoption of the Company's service rules and regulations to the current Savannah Electric customers;
- new fuel rate and base rate schedules that would apply to the Company's sale of electricity to the current Savannah Electric customers;
- adoption of a "merger transition adjustment" rate that would be used to more closely align Savannah Electric's existing base rates to those of the Company and a "merger transition credit" rate that would credit the additional revenues collected from former Savannah Electric customers to the Company's existing customers; and
- the issuance of additional shares of the Company's common stock to Southern Company in exchange for Southern Company's shares of Savannah Electric common stock.

The Company has also requested the Georgia PSC to better align the rates for Savannah Electric's customers with those of the Company. Currently, Savannah Electric customers pay slightly lower base rates and significantly higher fuel rates than the Company's customers. The overall effect is that Savannah Electric customers pay substantially higher overall costs for electricity. See "Fuel Cost Recovery" herein for additional information.

Rate Plans

In December 2004, the Georgia PSC approved the 2004 Retail Rate Plan for the three-year period ending December 31, 2007. Under the terms of the 2004 Retail Rate Plan, earnings are being evaluated annually against a retail return on common equity (ROE) range of 10.25 percent to 12.25 percent. Two-thirds of any earnings above 12.25 percent will be applied to rate refunds, with the remaining one-third retained by the Company. Retail rates were increased by approximately $194 million and customer fees were increased by approximately $9 million effective January 1, 2005 to cover the higher costs of purchased power; operation and maintenance expenses; environmental compliance; and continued investment in new generation, transmission and distribution facilities to support growth and ensure reliability. In 2005 the Company recorded $2.7 million revenue subject to refund for estimated earnings above 12.25 percent retail ROE.

The Company is required to file a general rate case by July 1, 2007, in response to which the Georgia PSC would be expected to determine whether the 2004 Retail Rate Plan should be continued, modified, or discontinued. Until then, the Company will not file for a general base rate increase unless its projected retail ROE falls below 10.25 percent. However, in connection with the Merger, the Company has requested Georgia PSC approval of a "merger transition adjustment" that would be used to adjust Savannah Electric's existing base rates to more closely match the existing base rates for the Company. See Note 3 to the financial statements under "Retail Regulatory Matters - Rate Plans" for additional information.

Plant McIntosh Construction Project

In December 2002 after a competitive bidding process, the Georgia PSC certified PPAs between Southern Power and the Company and Savannah Electric for capacity from Plant McIntosh Units 10 and 11, construction of which was completed in June 2005. In April 2003, Southern Power applied for FERC approval of these PPAs. In July 2003, the FERC accepted the PPAs to become effective June 1, 2005, subject to refund, and ordered that hearings be held. Intervenors opposed the FERC's acceptance of the PPAs, alleging that they did not meet the applicable standards for market-based rates between affiliates. To ensure the timely completion of the Plant McIntosh construction project and the availability of the units in the summer of 2005 for their retail customers, in May 2004, the Company and Savannah Electric requested the Georgia PSC to direct them to acquire the Plant McIntosh construction project. The Georgia PSC issued such an order and the transfer occurred on May 24, 2004 at a total cost of approximately $415 million, including

$14 million of transmission interconnection facilities. Subsequently, Southern Power filed a request to withdraw the PPAs and to terminate the ongoing FERC proceedings. In August 2004, the FERC issued a notice accepting the request to withdraw the PPAs and permitting such request to become effective by operation of law. However, the FERC made no determination on what additional steps may need to be taken with respect to testimony provided in the proceedings. See "FERC Matters - Intercompany Interchange Contract" above for additional information.

In connection with the 2004 Retail Rate Plan, the Georgia PSC approved the transfer of the Plant McIntosh construction project at a total fair market value of approximately $385 million. This value reflected an approximate $16 million disallowance, of which $13 million was attributable to the Company, and reduced the Company's 2004 net income by approximately $8 million. The Georgia PSC also certified a total completion cost of $547 million for the project. In June 2005, Plant McIntosh Units 10 and 11 were placed in service at a total cost that did not exceed the certified amount. Under the 2004 Retail Rate Plan, the Plant McIntosh revenue requirements impact will be reflected in the Company's rates evenly over the three years ending 2007. See Note 3 to the financial statements under "Retail Regulatory Matters -- Rate Plans" and "Plant McIntosh Construction Project" for additional information.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. In recent months, the Company has experienced higher than expected fuel costs for coal and natural gas. Those higher fuel costs have increased the under recovered fuel costs included in the balance sheets herein.

In May 2005, the Georgia PSC approved the Company's request to increase customer fuel rates by approximately 9.5 percent to recover under recovered fuel costs of approximately $508 million existing as of May 31, 2005 over a four-year period that began June 1, 2005. Under recovered fuel amounts for the period subsequent to June 1, 2005 totaled $327.5 million through December 31, 2005. The Georgia PSC's order instructed that such amounts be reviewed semi-annually beginning February 2006. If the amount under or over recovered exceeds $50 million at the evaluation date, the Company would be required to file for a temporary fuel rate change. In addition, Savannah Electric's under recovered fuel costs totaled $77.7 million at December 31, 2005. In accordance with the Georgia PSC order, Savannah Electric was scheduled to file an additional request for a fuel cost recovery increase in January 2006. The Company has agreed with a Georgia PSC staff recommendation to forego the temporary fuel rate process, and Savannah Electric has postponed its scheduled filing. Instead, the Company and Savannah Electric will file a combined request in March 2006 to increase the Company's fuel cost recovery rate.

The case will seek approval of a fuel cost recovery rate based upon future fuel cost projections for the combined Company and Savannah Electric generating fleet as well as the under recovered fuel balances existing at June 30, 2006. The new fuel cost recovery rate would be billed beginning in July 2006 to all of the Company's customers, including the existing Savannah Electric customers. Under recovered amounts as of the date of the Merger will be paid by the appropriate customer groups.

In August 2005, the Georgia PSC initiated an investigation of Savannah Electric's fuel practices. In February 2006, an investigation of the Company's fuel practices was initiated. The Company and Savannah Electric are responding to data requests and cooperating in the investigations. The final outcome of this matter cannot now be determined.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable cost and amounts billed in current regulated rates. Accordingly, any increase in the billing factor would have no significant effect on the Company's revenues or net income, but would increase annual cash flow.

Nuclear

As part of a potential expansion of Plant Vogtle, the Company and Southern Nuclear have notified the Nuclear Regulatory Commission (NRC) of their intent to apply for an early site permit (ESP) this year and a combined construction and operating license (COL) in 2008. In addition, a reactor design from Westinghouse Electric Company has been selected and a purchase agreement is being negotiated. Participation agreements have been reached with each of the existing Plant Vogtle co-owners. See Note 4 to the financial statements for additional information on

these co-owners. At this point, no final decision has been made regarding actual construction. The NRC's streamlined licensing process for new nuclear units allows utilities to seek regulatory approval at various stages. These stages include design certification, which is obtained by the reactor vendor, and the ESP and COL, which are each obtained by the owner-operators of the units. An ESP indicates site approval is obtained before a company decides to build and the COL provides regulatory approval for building and operating the plant. In addition, any generation by the Company must be certified by the Georgia PSC.

Southern Company also is participating in NuStart Energy Development, LLC (NuStart Energy), a broad-based nuclear industry consortium formed to share the cost of developing a COL and the related NRC review. NuStart Energy plans to complete detailed engineering design work and to prepare COL applications for two advanced reactor designs, then to choose one of the applications and file it for NRC review and approval. The COL ultimately is expected to be transferred to one or more of the consortium companies; however, at this time, none of them have committed to build a new nuclear plant.

Other Matters

In accordance with Financial Accounting Standards Board (FASB) Statement No. 87, Employers' Accounting for Pensions, the Company recorded non-cash pension income, before tax, of approximately $21 million, $35 million, and $54 million in 2005, 2004, and 2003, respectively. Postretirement benefit costs for the Company were $47 million, $44 million, and $41 million in 2005, 2004, and 2003, respectively. Both pension and postretirement costs are expected to trend upward. Such amounts are dependent on several factors including trust earnings and changes to the plans. A portion of pension income and postretirement benefit costs is capitalized based on construction-related labor charges. For the Company, pension income or expense and postretirement benefit costs are a component of the regulated rates and generally do not have a long-term effect on net income. For more information regarding pension and postretirement benefits, see Note 2 to the financial statements.

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

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

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

Electric Utility Regulation

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

As reflected in Note 1 to the financial statements under "Regulatory Assets and Liabilities," significant regulatory assets and liabilities have been recorded.

Management reviews the ultimate recoverability of these regulatory assets and liabilities based on applicable regulatory guidelines and accounting principles generally accepted in the United States. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

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

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

Unbilled Revenues

Revenues related to the sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated. Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, power delivery volume, and other operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.

New Accounting Standards

Income Taxes

In December 2004, the FASB issued FASB Staff Position 109-1, Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004 (FSP 109-1), which requires that the generation deduction be accounted for as a special tax deduction rather than as a tax rate reduction. The Company adopted FSP 109-1 in the first quarter of 2005 with no material impact on its financial statements.

Conditional Asset Retirement Obligations

Effective December 31, 2005, the Company adopted the provision of FASB Interpretation No. 47, Conditional Asset Retirement Obligations (FIN 47), which requires that an asset retirement obligation be recorded even though the timing and/or method of settlement are conditional on future events. Prior to December 2005, the Company did not recognize asset retirement obligations for asbestos removal because the timing of retirements was dependent on future events. For additional information, see Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal."

At December 31, 2005, the Company recorded additional asset retirement obligations (and assets) of approximately $91 million. The adoption of FIN 47 did not have any effect on the Company's income statement.

Stock Options

On January 1, 2006, the Company adopted FASB Statement No. 123R, Share-Based Payment, on a modified prospective basis. This statement requires that compensation cost relating to share-based payment transactions be recognized in financial statements. That cost will be measured based on the grant date fair value of the equity or liability instruments issued. Although the compensation expense required under the revised statement differs slightly, the impacts on the Company's financial statements are similar to the pro forma disclosures included in Note 1 to the financial statements under "Stock Options."

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition continued to be stable at December 31, 2005 with emphasis on cost control measures combined with significantly lower costs of capital, achieved through the refinancing and/or redemption of higher-cost securities. Cash flow from operations increased $56 million resulting primarily from increased retail operating revenues (see RESULTS OF OPERATIONS herein), partially offset by the increase in under recovered deferred fuel costs.

Fuel costs are generally recoverable in future periods and are reflected on the balance sheets as under recovered regulatory clause revenues. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information.

In 2005, gross utility plant additions were $906 million. These additions were primarily related to Plant McIntosh Units 10 and 11, transmission and distribution facilities, nuclear fuel, and equipment to comply with environmental standards. The majority of funds needed for gross property additions for the last several years have been provided from operating activities and capital contributions from Southern Company. The statements of cash flows provide additional details.

The Company's ratio of common equity to total capitalization -- including short-term debt -- was 48.3 percent in 2005, 47.7 percent in 2004, and 48.3 percent in 2003. The Company has received investment grade ratings from the major rating agencies.

Sources of Capital

The Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows. However, the type and timing of any future financings, if needed, will depend on market conditions, regulatory approval, and other factors.

The issuance of long-term securities by the Company is subject to the approval of the Georgia PSC. In addition, the issuance of short-term debt securities by the Company is subject to regulatory approval by the FERC following the repeal of the Public Utility Holding Company Act of 1935, as amended, on February 8, 2006. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the appropriate regulatory authorities, as well as the amounts registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company.

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

To meet short-term cash needs and contingencies, the Company had credit arrangements with banks totaling $780 million, of which $778 million was unused, at the beginning of 2006. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper and extendible commercial notes at the request and for the benefit of the Company and the other retail operating companies.

Proceeds from such issuances for the benefit of the Company are loaned directly to the Company and are not commingled with proceeds from issuances for the benefits of any other operating company. The obligations of each company under these arrangements are several; there is no cross affiliate credit support. As of December 31, 2005, the Company had outstanding $268 million of commercial paper and no extendible commercial notes.

At the beginning of 2006, bank credit arrangements were as follows:

		Expires		
Total	Unused	2006	2007	2010
		(in millions)		
$780	$778	$70	$350	$360

The credit arrangements that expire in 2006 allow for the execution of term loans for an additional two-year period.

Financing Activities

During 2005, the Company issued $810 million of long-term debt. The issuances were used to refund $635 million of long-term debt and to fund the Company's ongoing construction program.

Subsequent to December 31, 2005, the Company redeemed all of its outstanding preferred stock at a redemption price of $107 per share.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- or Baa3 or below. Generally, collateral may be provided for by a Southern Company guaranty, letter of credit, or cash. These contracts are primarily for physical electricity purchases and sales. At December 31, 2005, the maximum potential collateral requirements at a BBB- or Baa3 rating were approximately $6 million. The maximum potential collateral requirements at a rating below BBB- or Baa3 were approximately $245 million.

The Company is also party to certain derivative agreements that could require collateral and/or accelerated payment in the event of a credit rating change to below investment grade. These agreements are primarily for natural gas price risk management activities. At December 31, 2005, the Company had no material exposure related to these agreements.

Market Price Risk

Due to cost-based rate regulation, the Company has limited exposure to market rate 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 and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress tests, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company has entered into forward starting interest rate swaps that have been designated as hedges. These swaps have a notional amount of $300 million and are related to anticipated debt issuances over the next two years. The weighted average interest rate on outstanding variable long-term debt that has not been hedged at January 1, 2006 was 3.56 percent. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $3.3 million at January 1, 2006. For further information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

To mitigate residual risks relative to movements in electricity prices, the Company enters into fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, into similar contracts for gas purchases.

The Company has implemented a fuel hedging program at the instruction of the Georgia PSC. Fair

value of changes in energy-related derivative contracts and year-end valuations were as follows at December 31:

	Changes in Fair Value	
	2005	2004
	(in millions)	
Contracts beginning of year	**$5.8**	$ 3.2
Contracts realized or settled	**(40.0)**	(12.2)
Current period changes (a)	**60.8**	14.8
Contracts end of year	**$26.6**	$ 5.8

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

	Source of 2005 Year-End Valuation Prices		
	Total	Maturity	
	Fair Value	Year 1	1-3 Years
		(in millions)	
Actively quoted	**$26.8**	$16.4	$10.4
External sources	**(0.2)**	(0.2)	-
Contracts end of year	**$26.6**	$16.2	$10.4

Unrealized gains and losses from mark to market adjustments on derivative contracts related to the Company's fuel hedging programs are recorded as regulatory assets and liabilities. Realized gains and losses from these programs are included in fuel expense and are recovered through the Company's fuel cost recovery mechanism. Of the net gains, the Company is allowed to retain 25 percent in earnings. In 2005, the Company had a total net gain of $64.1 million, of which the Company retained $16.0 million. See Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Hedging Program" for additional information. Gains and losses on derivative contracts that are not designated as hedges are recognized in the statements of income as incurred. At December 31, 2005, the fair value of derivative energy contracts was reflected in the financial statements as follows:

	Amounts
	(in millions)
Regulatory liabilities, net	$26.7
Net income	(0.1)
Total fair value	$26.6

Unrealized gains (losses) recognized in income in 2005, 2004, and 2003 were not material. The Company is exposed to market price risk in the event of nonperformance by counterparties to the derivative energy contracts. The Company's policy is to enter into agreements with counterparties that have investment grade credit ratings by Moody's and Standard & Poor's or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to be $1.3 billion for 2006, $1.4 billion for 2007, and $1.3 billion for 2008. Environmental expenditures included in these amounts are $410 million, $674.6 million, and $515.8 million for 2006, 2007, and 2008, respectively. Actual construction costs may vary from this estimate because of changes in such factors as: business conditions; environmental regulations; nuclear plant regulations; FERC rules and transmission regulations; load projections; the cost and efficiency of construction labor, equipment, and materials; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

As a result of requirements by the NRC, the Company has established external trust funds for nuclear decommissioning costs. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning." Also as discussed in Note 1 to the financial statements under "Nuclear Fuel Disposal Costs," in 1993 the DOE implemented a special assessment over a 15-year period on utilities with nuclear plants to be used for the decontamination and decommissioning of its nuclear fuel enrichment facilities.

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the Georgia PSC and the FERC.

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

Amounts in the following chart exclude any effects on the Company of the Merger.

Contractual Obligations

	2006	2007-2008	2009-2010	After 2010	Total
			(in millions)		
Long-term debt [a] --					
Principal	$153	$306	$282	$4,563	$5,304
Interest	265	496	468	4,989	6,218
Preferred stock	15	-	-	-	15
Commodity derivative obligations[b]	12	-	-	-	12
Operating leases	34	58	44	58	194
Purchase commitments[c] --					
Capital [d]	1,251	2,738	2,421	-	6,410
Coal	1,579	2,220	694	40	4,533
Nuclear fuel	44	42	25	64	175
Natural gas[e]	577	525	511	2,047	3,660
Purchased power	343	689	559	994	2,585
Long-term service agreements	7	18	24	144	193
Trusts[f] --					
Nuclear decommissioning	7	14	14	117	152
Postretirement benefits	18	41	-	-	59
DOE assessments	4	-	-	-	4
Total	$4,309	$7,147	$5,042	$13,016	$29,514

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2006, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest risk.

(b) For additional information see Notes 1 and 6 to the financial statements herein.

(c) The Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses for the last three years were $1.5 billion, $1.4 billion, and $1.2 billion, respectively.

(d) The Company forecasts capital expenditures over a five-year period. Amounts represent current estimates of total expenditures, excluding those amounts related to contractual purchase commitments for uranium and nuclear fuel conversion, enrichment, and fabrication services. At December 31, 2005, significant purchase commitments were outstanding in connection with the construction program.

(e) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on the New York Mercantile Exchange future prices at December 31, 2005.

(f) Projections of nuclear decommissioning trust contributions are based on the 2004 Retail Rate Plan. The Company forecasts postretirement trust contributions over a three-year period. No contributions related to the Company's pension trust are currently expected during this period. See Note 2 to the financial statements for additional information related to the pension and postretirement plans, including estimated benefit payments. Certain benefit payments will be made through the related trusts. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2005 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales growth, storm cost recovery and repairs, environmental regulations and expenditures, the Company's projections for postretirement benefit trust contributions, financing activities, access to sources of capital, the proposed merger of Savannah Electric and the Company, the impacts of the adoption of new accounting rules, completion of construction projects, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will", "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory change, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, and implementation of the Energy Policy Act of 2005, and also changes in environmental, tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including FERC matters and the pending EPA civil action against the Company;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and population, and business growth (and declines);
- available sources and costs of fuels;
- ability to control costs;
- investment performance of the Company's employee benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate cases related to fuel cost recovery;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due;
- the ability to obtain new short- and long-term contracts with neighboring utilities;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents similar to the August 2003 power outage in the Northeast;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports, including the Form 10-K, filed by the Company from time to time with the Securities and Exchange Commission.

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

STATEMENTS OF INCOME

For the Years Ended December 31, 2005, 2004, and 2003

Georgia Power Company 2005 Annual Report

	2005	2004	2003
		(in thousands)	
Operating Revenues:			
Retail sales	**$5,642,812**	$4,776,985	$4,309,972
Sales for resale --			
Non-affiliates	**519,673**	246,545	259,376
Affiliates	**264,989**	166,245	174,855
Other revenues	**206,729**	181,033	169,304
Total operating revenues	**6,634,203**	5,370,808	4,913,507
Operating Expenses:			
Fuel	**1,830,829**	1,232,496	1,103,963
Purchased power --			
Non-affiliates	**408,563**	304,978	258,621
Affiliates	**761,466**	671,098	516,944
Other operations	**949,722**	902,167	827,972
Maintenance	**531,168**	498,114	419,206
Depreciation and amortization	**504,248**	275,488	349,984
Taxes other than income taxes	**259,825**	227,806	212,827
Total operating expenses	**5,245,821**	4,112,147	3,689,517
Operating Income	**1,388,382**	1,258,661	1,223,990
Other Income and (Expense):			
Allowance for equity funds used during construction	**26,808**	26,659	10,752
Interest income	**6,281**	6,657	15,625
Interest expense, net of amounts capitalized	**(221,199)**	(182,370)	(182,583)
Interest expense to affiliate trusts	**(59,510)**	(44,565)	-
Distributions on mandatorily redeemable preferred securities	**-**	(15,839)	(59,675)
Other income (expense), net	**5,742**	(11,362)	(10,551)
Total other income and (expense)	**(241,878)**	(220,820)	(226,432)
Earnings Before Income Taxes	**1,146,504**	1,037,841	997,558
Income taxes	**430,812**	379,170	366,311
Net Income	**715,692**	658,671	631,247
Dividends on Preferred Stock	**693**	670	670
Net Income After Dividends on Preferred Stock	**$714,999**	$658,001	$630,577

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2005, 2004, and 2003
Georgia Power Company 2005 Annual Report

	2005	2004	2003
		(in thousands)	
Operating Activities:			
Net income	**$ 715,692**	$ 658,671	$ 631,247
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization	**592,264**	361,958	424,321
Deferred income taxes and investment tax credits, net	**231,708**	251,623	199,265
Deferred expenses - affiliates	**1,268**	(10,563)	(7,399)
Allowance for equity funds used during construction	**(26,808)**	(26,659)	(10,752)
Pension, postretirement, and other employee benefits	**(19,468)**	(15,868)	(30,225)
Tax benefit of stock options	**15,711**	9,701	11,649
Other, net	**(11,068)**	(19,764)	18,929
Changes in certain current assets and liabilities --			
Receivables	**(591,498)**	(227,204)	(4,395)
Fossil fuel stock	**2,528**	(46,730)	(17,490)
Materials and supplies	**(53,942)**	618	(7,677)
Prepaid income taxes	**(43,626)**	14,358	(3,951)
Other current assets	**4,108**	(23,672)	1,599
Accounts payable	**110,118**	132,001	(62,553)
Accrued taxes	**85,098**	(64,563)	52,348
Accrued compensation	**3,822**	(6,664)	(3,111)
Other current liabilities	**33,289**	5,836	19,845
Net cash provided from operating activities	**1,049,196**	993,079	1,211,650
Investing Activities:			
Property additions	**(842,870)**	(741,151)	(717,993)
Nuclear decommissioning trust fund purchases	**(381,235)**	(541,048)	(656,806)
Nuclear decommissioning trust fund sales	**372,536**	532,349	648,107
Purchase of property from affiliates	**-**	(339,750)	(2)
Cost of removal net of salvage	**(29,428)**	(21,756)	(28,265)
Change in construction payables, net of joint owner portion	**4,037**	413	(32,223)
Other	**(315)**	(4,961)	1,008
Net cash used for investing activities	**(877,275)**	(1,115,904)	(786,174)
Financing Activities:			
Increase (decrease) in notes payable, net	**59,509**	70,956	(220,400)
Proceeds --			
Senior notes	**625,000**	600,000	1,000,000
Pollution control bonds	**185,000**	-	-
Mandatorily redeemable preferred securities	**-**	200,000	-
Capital contributions from parent company	**149,034**	260,068	40,809
Redemptions --			
Pollution control bonds	**(185,000)**	-	-
Senior notes	**(450,000)**	(200,000)	(665,000)
Mandatorily redeemable preferred securities	**-**	(200,000)	-
Payment of preferred stock dividends	**(546)**	(654)	(696)
Payment of common stock dividends	**(556,100)**	(565,500)	(565,800)
Other	**(21,679)**	(17,247)	(22,563)
Net cash provided from (used for) financing activities	**(194,782)**	147,623	(433,650)
Net Change in Cash and Cash Equivalents	**(22,861)**	24,798	(8,174)
Cash and Cash Equivalents at Beginning of Year	**33,497**	8,699	16,873
Cash and Cash Equivalents at End of Year	**$ 10,636**	$ 33,497	$ 8,699
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $10,871, $8,920, and $5,428 capitalized, respectively)	**$250,445**	$228,190	$215,463
Income taxes (net of refunds)	**207,973**	127,115	145,048

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

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BALANCE SHEETS
At December 31, 2005 and 2004
Georgia Power Company 2005 Annual Report

Assets	2005	2004
		(in thousands)
Current Assets:		
Cash and cash equivalents	$ 10,636	$ 33,497
Receivables --		
Customer accounts receivable	418,154	317,937
Unbilled revenues	141,875	140,027
Under recovered regulatory clause revenues	454,683	345,542
Other accounts and notes receivable	110,397	94,377
Affiliated companies	84,597	17,042
Accumulated provision for uncollectible accounts	(8,647)	(7,100)
Fossil fuel stock, at average cost	181,739	184,267
Vacation pay	59,190	57,372
Materials and supplies, at average cost	323,908	270,422
Prepaid expenses	70,825	32,695
Other	50,248	28,262
Total current assets	1,897,605	1,514,340
Property, Plant, and Equipment:		
In service	19,603,249	18,681,533
Less accumulated provision for depreciation	7,575,926	7,217,607
	12,027,323	11,463,926
Nuclear fuel, at amortized cost	134,798	124,745
Construction work in progress	563,155	766,140
Total property, plant, and equipment	12,725,276	12,354,811
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	68,188	66,192
Nuclear decommissioning trusts, at fair value	486,591	459,194
Other	71,468	64,571
Total other property and investments	626,247	589,957
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	500,882	505,664
Prepaid pension costs	476,458	450,270
Deferred under recovered regulatory clause revenues	295,116	-
Other regulatory assets	330,483	246,462
Other	195,716	160,834
Total deferred charges and other assets	1,798,655	1,363,230
Total Assets	$17,047,783	$15,822,338

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

BALANCE SHEETS
At December 31, 2005 and 2004
Georgia Power Company 2005 Annual Report

Liabilities and Stockholder's Equity	2005	2004
		(in thousands)
Current Liabilities:		
Securities due within one year	$ 167,317	$ 452,498
Notes payable	267,743	208,233
Accounts payable --		
Affiliated	285,019	194,253
Other	360,455	310,763
Customer deposits	129,293	115,661
Accrued taxes --		
Income taxes	150,896	78,269
Other	204,778	129,520
Accrued interest	88,885	74,529
Accrued vacation pay	45,602	44,894
Accrued compensation	137,303	127,340
Other	120,312	83,632
Total current liabilities	1,957,603	1,819,592
Long-term Debt (See accompanying statements)	4,179,218	3,709,852
Long-term Debt Payable to Affiliated Trusts (See accompanying statements)	969,073	969,073
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	2,730,303	2,556,040
Deferred credits related to income taxes	158,759	170,973
Accumulated deferred investment tax credits	287,726	300,018
Employee benefit obligations	358,137	331,002
Asset retirement obligations	627,465	504,515
Other cost of removal obligations	404,614	411,692
Other regulatory liabilities	97,015	84,678
Other	63,335	59,733
Total deferred credits and other liabilities	4,727,354	4,418,651
Total Liabilities	11,833,248	10,917,168
Preferred Stock (See accompanying statements)	-	14,609
Common Stockholder's Equity (See accompanying statements)	5,214,535	4,890,561
Total Liabilities and Stockholder's Equity	$17,047,783	$15,822,338
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2005 and 2004
Georgia Power Company 2005 Annual Report

	2005	2004	2005	2004
	(in thousands)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable --				
5.50% due December 1, 2005	**$ -**	$ 150,000		
Variable rate (1.66% to 1.96% at 1/1/05) due 2005	**-**	300,000		
6.20% due February 1, 2006	**150,000**	150,000		
4.875% due July 15, 2007	**300,000**	300,000		
4.10% due August 15, 2009	**125,000**	125,000		
Variable rate (4.53% at 1/1/06) due 2009	**150,000**	150,000		
4.00% to 6.00% due 2011-2045	**1,850,000**	1,225,000		
Total long-term notes payable	**2,575,000**	2,400,000		
Other long-term debt --				
Pollution control revenue bonds -- non-collateralized:				
2.83% to 5.45% due 2012-2034	**812,560**	812,560		
Variable rate (2.82% to 3.08% at 1/1/06) due 2011-2032	**873,330**	873,330		
Total other long-term debt	**1,685,890**	1,685,890		
Capitalized lease obligations	**74,484**	76,982		
Unamortized debt premium (discount), net	**(3,448)**	(522)		
Total long-term debt (annual interest requirement -- $205.5 million)	**4,331,926**	4,162,350		
Less amount due within one year	**152,708**	452,498		
Long-term debt excluding amount due within one year	**4,179,218**	3,709,852	**40.3%**	38.7%
Long-term Debt Payable to Affiliated Trusts:				
4.88% to 7.13% due 2042 (annual interest requirement -- $59.5 million)	**969,073**	**969,073**	**9.4**	10.1
Cumulative Preferred Stock:				
$100 stated value at 4.60%				
Authorized -- 5,000,000 shares				
Outstanding -- 145,689 shares (annual dividend requirement -- $0.7 million)	**14,609**	14,609		
Less amount due within one year	**14,609**	-		
Total cumulative preferred stock excluding amount due within one year	**-**	14,609	**0.0**	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	**2,643,012**	2,478,268		
Retained earnings	**2,261,698**	2,102,798		
Accumulated other comprehensive income (loss)	**(34,425)**	(34,755)		
Total common stockholder's equity	**5,214,535**	4,890,561	**50.3**	51.0
Total Capitalization	**$10,362,826**	$9,584,095	**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, 2005, 2004, and 2003

Georgia Power Company 2005 Annual Report

	Common Stock	Paid-In Capital	Retained Earnings	Other Comprehensive Income (loss)	Total
			(in thousands)		
Balance at December 31, 2002	$344,250	$2,156,080	$1,945,520	$(11,403)	$4,434,447
Net income after dividends on preferred stock	-	-	630,577	-	630,577
Capital contributions from parent company	-	52,458	-	-	52,458
Other comprehensive income (loss)	-	-	-	(11,471)	(11,471)
Cash dividends on common stock	-	-	(565,800)	-	(565,800)
Balance at December 31, 2003	**344,250**	**2,208,538**	**2,010,297**	**(22,874)**	**4,540,211**
Net income after dividends on preferred stock	-	-	658,001	-	658,001
Capital contributions from parent company	-	269,769	-	-	269,769
Other comprehensive income (loss)	-	-	-	(11,881)	(11,881)
Cash dividends on common stock	-	-	(565,500)	-	(565,500)
Other	-	(39)	-	-	(39)
Balance at December 31, 2004	**344,250**	**2,478,268**	**2,102,798**	**(34,755)**	**4,890,561**
Net income after dividends on preferred stock	-	-	**714,999**	-	**714,999**
Capital contributions from parent company	-	**164,745**	-	-	**164,745**
Other comprehensive income (loss)	-	-	-	**330**	**330**
Cash dividends on common stock	-	-	**(556,100)**	-	**(556,100)**
Other	-	**(1)**	**1**	-	-
Balance at December 31, 2005	**$344,250**	**$2,643,012**	**$2,261,698**	**$(34,425)**	**$5,214,535**

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

STATEMENTS OF COMPREHENSIVE INCOME

For the Years Ended December 31, 2005, 2004, and 2003

Georgia Power Company 2005 Annual Report

	2005	2004	2003
		(in thousands)	
Net income after dividends on preferred stock	**$714,999**	$658,001	$630,577
Other comprehensive income (loss):			
Change in additional minimum pension liability, net of tax of $(1,981), $(3,861) and $(5,133), respectively	**(3,140)**	(6,122)	(8,138)
Change in fair value of marketable securities, net of tax of $317 and $(114)	**501**	(181)	-
Changes in fair value of qualifying hedges, net of tax of $1,214, $(5,046) and $(3,241), respectively	**1,925**	(7,999)	(5,550)
Less: Reclassification adjustment for amounts included in net income, net of tax of $848, $1,528 and $1,208, respectively	**1,044**	2,421	2,217
Total other comprehensive income (loss)	**330**	(11,881)	(11,471)
Comprehensive Income	**$715,329**	$646,120	$619,106

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Georgia Power Company (Company) is a wholly owned subsidiary of Southern Company, which is the parent company of five retail operating companies, Southern Power Company (Southern Power), Southern Company Services (SCS), Southern Communications Services (SouthernLINC Wireless), Southern Company Holdings (Southern Holdings), Southern Nuclear Operating Company (Southern Nuclear), Southern Telecom, and other direct and indirect subsidiaries. The retail operating companies -- Alabama Power, the Company, Gulf Power, Mississippi Power, and Savannah Electric -- provide electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast. Southern Power constructs, owns, and manages Southern Company's competitive generation assets and sells electricity at market-based rates in the wholesale market. Contracts among the retail operating companies and Southern Power -- related to jointly owned generating facilities, interconnecting transmission lines, or the exchange of electric power -- are regulated by the Federal Energy Regulatory Commission (FERC). SCS -- the system service company -- provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications services to the retail operating companies and also markets these services to the public within the Southeast. Southern Telecom provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding subsidiary for Southern Company's investments in synthetic fuels and leveraged leases and various other energy-related businesses. Southern Nuclear operates and provides services to Southern Company's nuclear power plants. In January 2006, Southern Company completed the sale of substantially all the assets of Southern Company Gas, its competitive retail natural gas marketing subsidiary.

The equity method is used for subsidiaries in which the Company has significant influence but does not control and for variable interest entities where the Company is not the primary beneficiary. Certain prior years' data presented in the financial statements have been reclassified to conform to current year presentation.

Southern Company was registered as a holding company under the Public Utility Holding Company Act of 1935, as amended (PUHCA), until its repeal on February 8, 2006, and Southern Company and its subsidiaries, including the Company, were subject to the regulatory provisions of the PUHCA. The Company is subject to regulation by the FERC and the Georgia Public Service Commission (PSC). The Company follows accounting principles generally accepted in the United States and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires the use of estimates and the actual results may differ from those estimates.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, purchasing, accounting and statistical analysis, finance and treasury, tax, information resources, marketing, auditing, insurance and pension administration, human resources, systems and procedures, and other services with respect to business and operations and power pool operations. Costs for these services amounted to $330 million in 2005, $292 million in 2004, and $303 million in 2003. Cost allocation methodologies used by SCS were approved by the Securities and Exchange Commission prior to the repeal of the PUHCA 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 $328 million in 2005, $311 million in 2004, and $289 million in 2003.

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. Billings under these agreements with Southern Power amounted to $5.2 million in 2005, $4.8 million in 2004, and $5.3 million in 2003.

The Company has an agreement with SouthernLINC Wireless under which the Company receives digital wireless communications services and purchases digital equipment. Costs for these services amounted to $7.3 million in 2005, $7.7 million in 2004, and $7.4 million in 2003.

Southern Company holds a 30 percent ownership in Alabama Fuel Products, LLC (AFP), which produces synthetic fuel. The Company has an agreement with an indirect subsidiary of Southern Company that provides services for AFP. Under this agreement, the Company provides certain accounting functions, including processing and paying fuel transportation invoices, and the Company is reimbursed for its expenses. Amounts billed under this agreement totaled approximately $61 million in 2005, $53 million in 2004, and $38 million in 2003. In addition, the Company purchases synthetic fuel from AFP for use at plants Branch, McDonough, and Bowen. Fuel purchases totaled $216 million in 2005, $163 million in 2004, and $91 million in 2003.

The Company has entered into several purchased power agreements (PPAs) with Southern Power for capacity and energy. Expenses associated with these PPAs were $419 million, $282 million, and $203 million in 2005, 2004, and 2003, respectively. Additionally, the Company recorded a reduction of $1 million and an increase of $11 million of prepaid capacity expenses included on the balance sheets at December 31, 2005 and 2004, respectively. See Note 7 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, the Company operates Plant Scherer, and Gulf Power reimburses the Company for its proportionate share of the related expenses which were $4.3 million in 2005, $6.8 million in 2004, and $4.9 million in 2003. The Company has an agreement with Savannah Electric under which the Company jointly owns a portion of Plant McIntosh. Under this agreement, Savannah Electric operates Plant McIntosh, and the Company reimburses Savannah Electric for its proportionate share of the related expenses which were $5.5 million in 2005, $3.3 million in 2004, and $3.7 million in 2003. See Note 4 for additional information.

The Company provides incidental services to other Southern Company subsidiaries which are generally minor in duration and amount. However, with the hurricane damage experienced by Alabama Power, Gulf Power, and Mississippi Power in the last two years, assistance provided to aid in storm restoration, including company labor, contract labor, and materials, has caused an increase in these activities. The total amount of storm assistance provided to Alabama Power, Gulf Power, and Mississippi Power in 2005 was $4.1 million, $4.4 million, and $55 million, respectively. The total amount of storm assistance provided to Alabama Power and Gulf Power in 2004 was $4.1 million and $6.4 million, respectively. These activities were billed at cost.

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

The retail operating companies, including the Company, and Southern Power 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 7 under "Fuel Commitments" for additional information.

The Company has entered into an agreement to merge with Savannah Electric. See Note 3 under "Retail Regulatory Matters – Merger" 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.

Regulatory assets and (liabilities) reflected in the Company's balance sheets at December 31 relate to the following:

	2005	2004	Note
	(in millions)		
Deferred income tax charges	$ 501	$506	(a)
Premium on reacquired debt	170	177	(b)
Corporate building lease	52	53	(e)
Vacation pay	59	57	(d)
Postretirement benefits	18	20	(e)
DOE assessments	6	10	(c)
Generating plant outage costs	46	40	(g)
Other regulatory assets	33	11	(e)
Asset retirement obligation	65	(20)	(a)
Other cost of removal obligations	(404)	(412)	(a)
Deferred income tax credits	(159)	(171)	(a)
Environmental remediation	(19)	(22)	(f)
Purchased power	(33)	-	(f)
Other regulatory liabilities	(30)	(6)	(e)
Total	$ 305	$243	

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

(a) Asset retirement and removal liabilities are recorded, deferred income tax assets are recovered, and deferred tax liabilities are amortized over the related property lives, which may range up to 60 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities.

(b) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue which may range up to 50 years.

(c) Assessments for the decontamination and decommissioning of the DOE's nuclear fuel enrichment facilities are recorded annually from 1993 through 2006.

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

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

(f) Amortized over a three-year period ending in 2007. See Note 3 under "Retail Regulatory Matters - Rate Plans."

(g) See "Property, Plant, and Equipment" herein.

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, including plant, exists and, if impaired, write down the assets to their fair value. All regulatory assets and liabilities are reflected in rates.

Revenues

Energy and other revenues are recognized as services are provided. Unbilled revenues are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between the actual recoverable costs and amounts billed in current regulated rates.

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

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense includes the cost of purchased emission allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel. Total charges for nuclear fuel included in fuel expense amounted to $70 million in 2005, $73 million in 2004, and $74 million in 2003.

Nuclear Fuel Disposal Costs

The Company has contracts with the U.S. Department of Energy (DOE) that provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent nuclear fuel in 1998 as required by the contracts, and the Company is pursuing legal remedies against the government for breach of contract. Sufficient pool storage capacity for spent fuel is available at Plant Vogtle to maintain full-core discharge capability for both units into 2015. Construction of an on-site dry storage facility at Plant Vogtle is expected to begin in sufficient time to maintain pool full-core discharge capability. At Plant Hatch, an on-site dry storage facility is operational and can be expanded to accommodate spent fuel through the life of the plant.

Also, the Energy Policy Act of 1992 required the establishment of a Uranium Enrichment Decontamination and Decommissioning Fund, which is funded in part by a special assessment on utilities with nuclear plants. This assessment has been paid over a 15-

year period; the final installment is scheduled to occur in 2006. 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 interest, estimates its remaining liability at December 31, 2005 under this law to be approximately $4 million.

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.

Manufacturer's Tax Credits

The State of Georgia provides a tax credit for qualified investment property to manufacturing companies that construct new facilities. The credit ranges from 1 percent to 8 percent of qualified construction expenditures depending upon the county in which the new facility is located. The Company's policy is to recognize these credits when management believes that they are more likely than not to be allowed by the Georgia Department of Revenue. Manufacturer's tax credits of $12.5 million, $12.9 million, and $12.0 million were recorded in 2005, 2004, and 2003, respectively.

Property, Plant, and Equipment

The Company's property, plant, and equipment consisted of the following at December 31 (in millions):

	2005	2004
Generation	**$ 9,571**	$ 9,002
Transmission	**2,994**	2,870
Distribution	**5,953**	5,744
General	**1,057**	1,038
Plant acquisition adjustment	**28**	28
Total plant in service	**$ 19,603**	$18,682

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

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense as incurred or performed with the exception of certain generating plant maintenance costs. As mandated by the Georgia PSC, the Company defers and amortizes nuclear refueling costs over the unit's operating cycle before the next refueling. The refueling cycles are 18 and 24 months for plants Vogtle and Hatch, respectively. In accordance with the Georgia PSC 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.

Depreciation and Amortization

Depreciation of the original cost of plant in service is provided primarily by using composite straight-line rates, which approximated 2.6 percent in 2005, 2.6 percent in 2004, and 2.7 percent in 2003. Depreciation studies are conducted periodically to update the composite rates that are approved by the Georgia PSC. In connection with the new retail rate plan for the Company ending December 31, 2007 (2004 Retail Rate Plan), effective January 1, 2005, the depreciation rates were revised by the Georgia PSC. The revised depreciation rates had no material impact on the Company's financial statements.

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.

Under the three-year retail rate plan for the Company ending December 31, 2004 (2001 Retail Rate Plan), the Company discontinued recording accelerated depreciation and amortization. Also, the Company was ordered to amortize $333 million, the cumulative balance previously expensed, equally over three years as a credit to amortization expense beginning January

2002. Additionally, the Company was ordered to recognize new Georgia PSC certified purchased power costs in rates evenly over the three years covered by the 2001 Retail Rate Plan. As a result of the purchased power regulatory adjustment, the Company recorded amortization expenses of $14 million in 2003. The Company recorded a credit to amortization expense of $77 million in 2004. See Note 3 under "Retail Regulatory Matters - Rate Plans" for additional information.

Asset Retirement Obligations and Other Costs of Removal

Effective January 1, 2003, the Company adopted FASB Statement No. 143, Accounting for Asset Retirement Obligations. Statement No. 143 established new accounting and reporting standards for legal obligations associated with the ultimate costs of retiring long-lived assets. The present value of the ultimate costs for an asset's future retirement is recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In addition, effective December 31, 2005, the Company adopted the provisions of FASB Interpretation No. 47, Conditional Asset Retirement Obligations (FIN 47), which requires that an asset retirement obligation be recorded even though the timing and/or method of settlement are conditional on future events. Prior to December 2005, the Company did not recognize asset retirement obligations for asbestos removal because the timing of their retirements was dependent on future events. The Company has received approval from the Georgia PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations will continue to be reflected on the balance sheets as a regulatory liability. Therefore, the Company had no cumulative effect to net income resulting from the adoption of Statement No. 143 or FIN 47.

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. The fair value of assets legally restricted for settling retirement obligations related to nuclear facilities as of December 31, 2005 was $487 million. In addition, the Company has recognized retirement obligations related to various landfill sites, ash ponds, and underground storage tanks. The Company also recorded additional asset retirement obligations (and assets) of approximately $91 million related to asbestos removal. The Company has also identified retirement obligations related to certain transmission and distribution facilities, leasehold improvements, equipment on customer property, and property associated with the Company's rail lines. However, liabilities for the removal of these assets have not been 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 allowed removal costs in accordance with its regulatory treatment. Any difference between costs recognized under Statement No. 143 and FIN 47 and those reflected in rates are recognized as either a regulatory asset or liability in the balance sheets as ordered by the Georgia PSC. See "Nuclear Decommissioning" herein for further information on amounts included in rates.

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

	2005	2004
	(in millions)	
Balance beginning of year	**$505**	$476
Liabilities incurred	**91**	-
Liabilities settled	**(2)**	(2)
Accretion	**33**	31
Balance end of year	**$627**	$505

If FIN 47 had been adopted as of December 31, 2004, the pro forma asset retirement obligations would have been $591 million.

Nuclear Decommissioning

The Nuclear Regulatory Commission (NRC) requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has external trust funds to comply with the NRC's regulations. Use of the funds is restricted to nuclear decommissioning activities and the funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and state PSCs, as well as the Internal Revenue Service (IRS). The trust funds are invested in a tax-

efficient manner in a diversified mix of equity and fixed income securities and are classified as available-for-sale. The trust funds are included in the balance sheets at fair value, as obtained from quoted market prices for the same or similar investments. Details of the securities held in these trusts at December 31 are as follows:

2005	Unrealized Gains	Unrealized Losses	Fair Value
		(in millions)	
Equity	$76.7	$(6.3)	$325.5
Debt	2.8	(0.8)	135.3
Other	-	-	25.8
Total	**$79.5**	**$(7.1)**	**$486.6**

2004	Unrealized Gains	Unrealized Losses	Fair Value
		(in millions)	
Equity	$68.7	$(4.0)	$308.2
Debt	5.3	(0.1)	138.0
Other	-	-	13.0
Total	$74.0	$(4.1)	$459.2

The contractual maturities of debt securities at December 31, 2005 are as follows: $3.2 million in 2006; $34.9 million in 2007-2010; $32.4 million in 2011-2015; and $57.2 million thereafter.

Sales of the securities held in the trust funds resulted in proceeds of $372.5 million, $532.3 million, and $648.1 million in 2005, 2004, and 2003, respectively, all of which were re-invested. Net realized gains (losses) were $12.6 million, $14.1 million, and $21.3 million in 2005, 2004, and 2003, respectively. Realized gains and losses are determined on a specific identification basis. In accordance with regulatory guidance, all realized and unrealized gains and losses are included in the regulatory liability for Asset Retirement Obligations in the balance sheets and are not included in net income or other comprehensive income. Unrealized gains and losses are considered non-cash transactions for purposes of the statements of cash flow. Unrealized losses were not material in any period presented and do not represent any impairment of the underlying investments.

Amounts previously recorded in internal reserves are being transferred into the external trust funds over periods approved by the Georgia PSC. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed plans with the NRC to ensure that, over time -- the deposits and earnings of the external trust funds will provide the minimum funding amounts prescribed by the NRC. Annual provisions for nuclear decommissioning are based on an annuity method as approved by the Georgia PSC. The amount expensed in 2005 and fund balances were as follows:

	Plant Hatch	Plant Vogtle
	(in millions)	
Amount expensed in 2005	$ -	$ 7
Accumulated provisions:		
External trust funds, at fair value	$313	$174
Internal reserves	-	1
Total	$313	$175

Site study cost is the estimate to decommission a specific facility as of the site study year. The estimated costs of decommissioning based on the most current study performed in 2003 for the Company's ownership interests in plants Hatch and Vogtle were as follows:

	Plant Hatch	Plant Vogtle
Decommissioning periods:		
Beginning year	2034	2027
Completion year	2065	2048
	(in millions)	
Site study costs:		
Radiated structures	$497	$452
Non-radiated structures	49	58
Total	$546	$510

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

Under the 2001 Retail Rate Plan, the Georgia PSC approved the annual decommissioning costs for ratemaking of $9 million. This amount was based on the NRC generic estimate to decommission the radioactive

portion of the facilities as of 2000. The estimates were $383 million and $282 million for plants Hatch and Vogtle, respectively. Significant assumptions used to determine the costs for ratemaking included an estimated inflation rate of 4.7 percent and an estimated trust earnings rate of 6.5 percent.

Under the 2004 Retail Rate Plan, effective January 1, 2005, the Georgia PSC decreased the annual decommissioning costs for ratemaking to $7 million. This amount is based on the NRC generic estimate to decommission the radioactive portion of the facilities as of 2003. The estimates are $421 million and $326 million for plants Hatch and Vogtle, respectively. Significant assumptions used to determine the costs for ratemaking include an estimated inflation rate of 3.1 percent and an estimated trust earnings rate of 5.1 percent. Another significant assumption used was the change in the operating license for Plant Hatch. In January 2002, the NRC granted the Company a 20-year extension of the licenses for both units at Plant Hatch which permits the operation of units 1 and 2 until 2034 and 2038, respectively. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for the anticipated cost of decommissioning.

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

In accordance with regulatory treatment, the Company records AFUDC. AFUDC represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, it increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation expense. Interest related to the construction of new facilities not included in the Company's retail rates is capitalized in accordance with standard interest capitalization requirements. For the years 2005, 2004, and 2003, the average AFUDC rates were 8.02 percent, 8.22 percent, and 5.51 percent, respectively. AFUDC and interest capitalized, net of taxes, were 4.7 percent and 4.9 percent of net income after dividends on preferred stock for 2005 and 2004, respectively, and less than 3 percent for 2003.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment provision is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change. See Note 3 under "Retail Regulatory Matters" and "Plant McIntosh Construction Project" for information regarding a regulatory disallowance by the Georgia PSC in December 2004.

Storm Damage Reserve

The Company maintains a reserve for property damage to cover the cost of damages from major storms to its transmission and distribution lines and the cost of uninsured damages to its generation facilities and other property as mandated by the Georgia PSC. The Company accrues $6.3 million annually that is recoverable through base rates. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for storm damage costs.

Environmental Cost Recovery

Under Georgia PSC ratemaking provisions, $22 million has been deferred in a regulatory liability account related to certain environmental insurance settlements. Under the 2004 Retail Rate Plan, this regulatory liability is being amortized over a three-year period beginning January 1, 2005. However, the Georgia PSC also approved an annual environmental accrual of $5.4 million. Environmental remediation expenditures are charged against the reserve as they are incurred. The annual accrual amount will be reviewed and adjusted in future regulatory proceedings.

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 average costs 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.

Fuel Inventory

Fuel inventory includes the average costs of oil, coal, natural gas, and emission allowances. Fuel is charged to inventory when purchased and then expensed as used. Emission allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Stock Options

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

For pro forma purposes, the Company generally recognizes stock option expense on a straight-line basis over the vesting period. Stock options granted to employees who are eligible for retirement are expensed at the grant date.

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

Net Income	As Reported	Options Impact	Pro Forma
		(in millions)	
2005	**$715**	**$(3)**	**$712**
2004	$658	(3)	$655
2003	$631	(4)	$627

The estimated fair value of stock options granted in 2005, 2004, and 2003 was derived using the Black-Scholes stock option pricing model. The following table shows the assumptions and the weighted average fair values of stock options.

	2005	2004	2003
Interest rate	**3.90%**	3.10%	2.70%
Average expected life of stock options (in years)	**5.0**	5.0	4.3
Expected volatility of common stock	**17.90%**	19.60%	23.60%
Expected annual dividends on common stock	**$1.43**	$1.40	$1.37
Weighted average fair value of stock options granted	**$3.90**	$3.29	$3.59

See Note 8 for additional information.

Financial Instruments

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

through current period income and are recorded on a net basis in the statements of income.

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

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

	Carrying Amount	Fair Value
Long-term debt:	(in millions)	
2005	**$5,227**	**$5,195**
2004	$5,055	$5,125

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

Comprehensive Income

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

Variable Interest Entities

The primary beneficiary of a variable interest entity must consolidate the related assets and liabilities. The Company has established certain wholly-owned trusts to issue preferred securities. However, the Company is not the primary beneficiary of the trusts. Therefore, the investments in these trusts are reflected as Other Investments, and the related loans from the trusts are reflected as Long-Term Debt Payable to Affiliated Trusts on the balance sheets. See Note 6 under "Mandatorily Redeemable Preferred Securities/Long-Term Debt Payable to Affiliated Trusts" for additional information.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. The plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). In 2005, the plan was amended to provide an additional monthly supplement to certain retirees. No contributions to the plan are expected for the year ending December 31, 2006. The Company also provides certain non-qualified benefit plans for a selected group of management and highly compensated employees. Benefits under these non-qualified plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees. The Company funds related trusts to the extent required by the Georgia PSC and the FERC. For the year ended December 31, 2006, such contributions are expected to total approximately $18.4 million. The measurement date for plan assets and obligations is September 30 for each year presented.

Pension Plans

The accumulated benefit obligation for the pension plans was $1.9 billion in 2005 and $1.7 billion in 2004. Changes during the year in the projected benefit obligations, accumulated benefit obligations, and the fair value of plan assets was as follows:

Projected Benefit Obligation	**2005**	2004
	(in millions)	
Balance at beginning of year	**$1,885**	$1,727
Service cost	**45**	42
Interest cost	**106**	101
Benefits paid	**(85)**	(85)
Plan amendments	**13**	1
Actuarial loss	**91**	99
Balance at end of year	**$2,055**	$1,885

	Plan Assets	
	2005	2004
	(in millions)	
Balance at beginning of year	**$2,181**	$2,055
Actual return on plan assets	**339**	207
Benefits paid	**(80)**	(81)
Balance at end of year	**$2,440**	$2,181

In 2005, the projected benefit obligations for the qualified and non-qualified pension plans were $1.945 billion and $110 million, respectively. All plan assets are related to the qualified plan.

Pension plan assets are managed and invested in accordance with all applicable requirements including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity, as described in the table below. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes.

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

	Plan Assets		
	Target	**2005**	2004
Domestic equity	36%	**40%**	36%
International equity	24	**24**	20
Fixed income	15	**17**	26
Real estate	15	**13**	10
Private equity	10	**6**	8
Total	100%	**100%**	100%

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

	2005	2004
	(in millions)	
Funded status	**$385**	$295
Unrecognized transition amount	**(4)**	(8)
Unrecognized prior service cost	**109**	108
Unrecognized net actuarial gain (loss)	**(54)**	21
Prepaid pension asset, net	**$436**	$416

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

	2005	2004
	(in millions)	
Prepaid pension asset	**$476**	$450
Employee benefit obligations	**(96)**	(89)
Other property and investments	**15**	19
Accumulated other comprehensive income	**41**	36
Prepaid pension asset, net	**$436**	$416

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

	2005	2004	2003
	(in millions)		
Service cost	**$ 45**	$ 42	$ 38
Interest cost	**106**	101	100
Expected return on plan assets	**(182)**	(180)	(179)
Recognized net (gain)/loss	**3**	(5)	(19)
Net amortization	**7**	7	6
Net pension (income)	**$(21)**	$(35)	$ (54)

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2005, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2006	$ 88
2007	91
2008	94
2009	97
2010	102
2011 to 2015	$607

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	
	2005	2004
	(in millions)	
Balance at beginning of year	**$726**	$723
Service cost	**10**	10
Interest cost	**41**	41
Benefits paid	**(32)**	(31)
Actuarial loss	**24**	42
Plan amendments	**-**	(59)
Balance at end of year	**$769**	$726

	Plan Assets	
	2005	2004
	(in millions)	
Balance at beginning of year	**$299**	$265
Actual return on plan assets	**38**	32
Employer contributions	**40**	33
Benefits paid	**(32)**	(31)
Balance at end of year	**$345**	$299

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

	Plan Assets		
	Target	**2005**	2004
Domestic equity	43%	**43%**	42%
International equity	21	**22**	23
Domestic fixed income	19	**19**	19
Global fixed income	11	**11**	11
Real estate	4	**3**	3
Private equity	2	**2**	2
Total	100%	**100%**	100%

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

	2005	2004
	(in millions)	
Funded status	**$(424)**	$(428)
Unrecognized transition obligation	**70**	78
Unrecognized prior service cost	**25**	27
Unrecognized net loss	**203**	203
Fourth quarter contributions	**21**	15
Employee benefit obligations recognized in the balance sheets	**$(105)**	$(105)

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

	2005	2004	2003
	(in millions)		
Service cost	**$10**	$ 10	$ 9
Interest cost	**41**	41	40
Expected return on plan assets	**(22)**	(25)	(24)
Net amortization	**18**	18	16
Net postretirement cost	**$47**	$ 44	$ 41

In the third quarter 2004, the Company prospectively adopted FASB Staff Position (FSP) 106-2, Accounting and Disclosure Requirements related to the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (Medicare Act). The Medicare Act provides a 28 percent prescription drug subsidy for Medicare eligible retirees. FSP 106-2 requires recognition of the impacts of the Medicare Act in the accumulated postretirement benefit obligation (APBO) and future cost of service for postretirement medical plans. The effect of the subsidy reduced the Company's expenses for the six months ended December 31, 2004 and for the year ended December 31, 2005 by approximately $5 million and $10 million, respectively, and is expected to have a similar impact on future expenses.

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the accumulated benefit obligation for the postretirement plans. Estimated benefit payments are reduced by drug

subsidy receipts expected as a result of the Medicare Act as follows:

	Benefit Payments	Subsidy Receipts	Total
	(in millions)		
2006	$ 37	$ (3)	$ 34
2007	39	(4)	35
2008	42	(4)	38
2009	46	(4)	42
2010	50	(5)	45
2011 to 2015	280	(34)	246

Actuarial Assumptions

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

	2005	2004	2003
Discount	**5.50%**	5.75%	6.00%
Annual salary increase	**3.00**	3.50	3.75
Long-term return on plan assets	**8.50**	8.50	8.50

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

An additional assumption used in measuring the APBO was a weighted average medical care cost trend rate of 10.25 percent for 2005, decreasing gradually to 4.75 percent through the year 2014, 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, 2005, as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$70	$62
Service and interest costs	5	4

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides a 75 percent matching contribution up to 6 percent of an employee's base salary. Total matching contributions made to the plan for the years 2005, 2004, and 2003 were $19 million, $18 million, and $18 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, and citizen enforcement of environmental requirements such as opacity and other air quality standards, 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 pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S District Court for the Northern District of Georgia against the Company and Alabama Power, alleging that the Company and Alabama Power had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws with respect to certain coal-fired generating facilities. Through subsequent amendments and other legal proceedings, the EPA added Savannah Electric as a defendant to the original action and filed a separate action against Alabama Power after it was dismissed from the original action. In these lawsuits, the

EPA alleges that NSR violations occurred at eight coal-fired generating facilities, including the Company's Plants Bowen and Scherer. The civil action requests penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. On June 3, 2005, the U.S. District for the Northern District of Alabama issued a decision in favor of Alabama Power on two primary legal issues in the case; however, the decision does not resolve the case, nor does it address other legal issues associated with the EPA's allegations. In accordance with a separate court order, Alabama Power and the EPA are currently participating in mediation with respect to the EPA's claims. The action against the Company and Savannah Electric has been administratively closed since the spring of 2001, and none of the parties has sought to reopen the case.

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $32,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in this case could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

Plant Wansley Environmental Litigation

In December 2002, the Sierra Club, Physicians for Social Responsibility, Georgia Forestwatch, and one individual filed a civil suit in the U.S. District Court for the Northern District of Georgia against the Company for alleged violations of the Clean Air Act at four of the units at Plant Wansley. 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. The liability phase of the case has concluded with the court ruling in favor of the Company in part and the plaintiffs in part. In March 2005, the U.S. Court of Appeals for the Eleventh Circuit accepted the Company's petition for review of the district court's order, and oral arguments were held on January 24, 2006. The district court case has been administratively closed pending that appeal. If necessary, the district court will hold a separate trial which will address civil penalties and possible injunctive relief requested by the plaintiffs. The ultimate outcome of this matter cannot currently be determined; however, an adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

Environmental Remediation

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. In 1995, the EPA designated the Company and four other unrelated entities as potentially responsible parties at a site in Brunswick, Georgia that is listed on the federal National Priorities List. As of December 31, 2005, the Company had recorded approximately $6 million in cumulative expenses associated with the Company's agreed-upon share of the removal and remedial investigation and feasibility study costs for the Brunswick site. Additional claims for recovery of natural resource damages at the site are anticipated. The Company has also recognized $36 million in cumulative expenses through December 31, 2005 for the assessment and anticipated cleanup of sites on the Georgia Hazardous Sites Inventory.

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 the Company'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.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates at market-based prices. The Company also has FERC authority to make short-term opportunity sales at market rates. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in that proceeding. In February 2005, Southern Company submitted responsive information. In February 2006, the FERC agreed to allow the parties to conduct settlement discussions. Any new market-based rate transactions in its retail service territory entered into after February 27, 2005 are subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. The impact of such sales through December 31, 2005 is not expected to exceed $4.9 million. The refund period covers 15 months. In the event that the FERC's default mitigation measures for entities that are found to have market power are ultimately applied, the Company may be required to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates. The final outcome of this matter will depend on the form in which the final methodology for assessing generation market power and mitigation rules may be ultimately adopted and cannot be determined at this time.

In addition, in May 2005, the FERC started an investigation to determine whether Southern Company satisfies the other three parts of the FERC's market-based rate analysis: transmission market power, barriers to entry, and affiliate abuse or reciprocal dealing. The FERC established a new refund period related to this expanded investigation. Any and all new market-based rate transactions both inside and outside Southern Company's retail service territory involving any Southern Company subsidiary, including the Company, will be subject to refund to the extent the FERC orders lower rates as a result of this new investigation, with the 15-month refund period beginning July 19, 2005. The impact of such sales through December 31, 2005 is not expected to exceed $10.9 million, of which $3.2 million relates to sales inside the retail service territory as discussed above. The FERC also directed that this expanded proceeding be held in abeyance pending the outcome of the proceeding on the IIC discussed below.

The Company believes that there is no meritorious basis for this proceeding and is vigorously defending itself in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in this proceeding, cannot now be determined.

Intercompany Interchange Contract

The Company's generation fleet in its retail service territory is operated under the IIC, as approved by the FERC. In May 2005, the FERC also initiated a new proceeding to examine (1) the provisions of the IIC among Alabama Power, the Company, Gulf Power, Mississippi Power, Savannah Electric, Southern Power, and SCS, as agent, under the terms of which the power pool of Southern Company is operated, and, in particular, the propriety of the continued inclusion of Southern Power as a party to the IIC, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining Southern Power as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of Southern Power, the FERC authorized Southern Power's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct. The FERC order directs that the administrative law judge who presided over the McIntosh PPA proceeding involving an approval of PPAs between Southern Power and the Company and Savannah Electric, be assigned to preside over the hearing in this proceeding and that the testimony and exhibits presented in that proceeding be preserved to the extent appropriate. Hearings are scheduled for September 2006. Effective July 19, 2005, revenues from transactions under the IIC involving any Southern Company subsidiaries, including the Company, are subject to refund to the extent the FERC orders any changes to the IIC.

The Company believes that there is no meritorious basis for this proceeding and is vigorously defending itself in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in this proceeding, cannot now be determined.

Generation Interconnection Agreements

In July 2003, the FERC issued its final rule on the standardization of generation interconnection agreements and procedures (Order 2003). Order 2003 shifts much of the financial burden of new transmission investment from the generator to the transmission provider. The FERC has indicated that Order 2003, which was effective January 20, 2004, is to be applied prospectively to interconnection

agreements. Subsidiaries of Tenaska, Inc., as counterparties to previously executed interconnection agreements with the Company and another Southern Company subsidiary, have filed complaints at the FERC requesting that the FERC modify the agreements and that the Company refund a total of $7.9 million previously paid for interconnection facilities, with interest. The Company has opposed such relief and the proceedings are still pending. The impact of Order 2003 and its subsequent rehearings on the Company and the final results of these matters cannot be determined at this time.

Race Discrimination Litigation

In July 2000, a lawsuit alleging race discrimination was filed by three of the Company's employees against the Company, Southern Company, and SCS in the Superior Court of Fulton County, Georgia. Shortly thereafter, the lawsuit was removed to the U.S. District Court for the Northern District of Georgia and amended to add four more plaintiffs. The lawsuit also raised claims on behalf of a purported class. The plaintiffs sought compensatory and punitive damages in an unspecified amount, as well as injunctive relief.

Following various court decisions in favor of the defendants and subsequent appeals by the plaintiffs, on July 13, 2005, the plaintiffs filed a petition for writ of certiorari to the U.S. Supreme Court. On October 17, 2005, the petition was denied. This matter is now concluded.

Right of Way Litigation

Southern Company and certain of its subsidiaries, including the Company, Gulf Power, Mississippi Power, and Southern Telecom, have been named as defendants in numerous lawsuits brought by landowners since 2001. 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 exceed the easements or other property rights held by defendants. The plaintiffs assert claims for, among other things, trespass and unjust enrichment, and seek compensatory and punitive damages and injunctive relief. Management believes that the Company has complied with applicable laws and that the plaintiffs' claims are without merit.

In January 2005, the Superior Court of Decatur County, Georgia granted partial summary judgment in a lawsuit brought by landowners against the Company based on the plaintiffs' declaratory judgment claim that the easements do not permit general telecommunications use. The Company appealed this ruling to the Georgia Court of Appeals. The Georgia Court of Appeals reversed, in part, the court's order and remanded the case to the trial court for the determination of further issues. After the Court of Appeals' decision, the plaintiffs filed a motion for reconsideration, which was denied, and a petition for certiorari to the Georgia Supreme Court, which is currently pending. The question of damages and other liabilities or remedies issues with respect to this action, if any, will be decided at a future trial. In the event of an adverse verdict in the case, the Company could appeal both liability and damages or other relief granted. An adverse outcome in these matters could result in substantial judgments; however, the final outcome cannot now be determined.

In addition, in late 2001, certain subsidiaries of Southern Company, including Alabama Power, the Company, Gulf Power, Mississippi Power, Savannah Electric, and Southern Telecom, were named as defendants in a lawsuit brought by a telecommunications company that uses certain of the defendants' rights of way. This lawsuit alleges, among other things, that the defendants are contractually obligated to indemnify, defend, and hold harmless the telecommunications company from any liability that may be assessed against it in pending and future right of way litigation. The Company believes that the plaintiff's claims are without merit. In the fall of 2004, the trial court stayed the case until resolution of the underlying landowner litigation discussed above. In January 2005, the Georgia Court of Appeals dismissed the telecommunications company's appeal of the trial court's order for lack of jurisdiction. An adverse outcome in this matter, combined with an adverse outcome against the telecommunications company in one or more of the right of way lawsuits, could result in substantial judgments; however, the final outcome of these matters cannot now be determined.

Property Tax Dispute

The Company is involved in a significant property tax dispute with Monroe County, Georgia (Monroe County). The Monroe County Board of Tax Assessors (Monroe Board) has issued assessments reflecting substantial

increases in the ad valorem tax valuation of the Company's 22.95 percent ownership interest in Plant Scherer, which is located in Monroe County, for tax years 2003, 2004, and 2005. The Company is aggressively pursuing administrative appeals in Monroe County and has filed notices of arbitration for all three years. The appeals are currently stayed, pending the outcome of the litigation discussed below.

In November 2004, the Company filed suit, on its behalf, against the Monroe Board in the Superior Court of Monroe County. The Company contends that Monroe County acted without statutory authority in changing the valuation of a centrally assessed utility as established by the Revenue Commissioner of the State of Georgia and requests injunctive relief prohibiting Monroe County and the Monroe Board from unlawfully changing the value of Plant Scherer and ultimately collecting additional ad valorem taxes from the Company. On December 22, 2005, the court granted Monroe County's motion for summary judgment. The Company has filed an appeal of the Superior Court's decision to the Georgia Supreme Court.

If the Company is not successful in its administrative appeals and if Monroe County is successful in defending the litigation, the Company could be subject to total additional taxes through December 31, 2005 of up to $13 million, plus penalties and interest. The ultimate outcome of this matter cannot currently be determined.

Retail Regulatory Matters

Merger

On December 13, 2005, the Company and Savannah Electric entered into an Agreement and Plan of Merger. Savannah Electric will merge into the Company, with the Company continuing as the surviving corporation (the Merger). At the effective time of the Merger, each share of the Company's common stock will remain issued and outstanding; each share of the Company's preferred stock issued and outstanding will have been redeemed prior to the Merger; the issued and outstanding shares of Savannah Electric common stock, all of which are held by Southern Company, will be converted into the right to receive 1,500,000 shares of the Company's common stock; and each share of Savannah Electric preferred stock issued and outstanding immediately prior to the Merger will be converted into the right to receive one share of a new series of the Company's Class A Preferred Stock. The Merger must be approved by the preferred shareholders of Savannah Electric and is subject to the receipt of certain regulatory approvals from the FERC, the Georgia PSC, and the Federal Communications Commission. Pending regulatory approvals, the Merger is expected to be completed by July 2006. The Merger is not expected to have a material impact on the Company's financial statements.

While the Georgia PSC does not have specific approval authority over the merger of electric utilities, the Company and Savannah Electric have filed an application with the Georgia PSC with respect to certain approvals that will be necessary to effectively complete the Merger. In particular, the Company and Savannah Electric plan to seek the approval of the Georgia PSC with respect to the following matters:

- the transfer of Savannah Electric's generating facilities and certification of the generating facilities as the Company's assets;
- amendments to the Company's Integrated Resource Plan to add the current Savannah Electric's customers and generating facilities;
- the transfer of Savannah Electric's assigned service territory to the Company;
- adoption of the Company's service rules and regulations to the current Savannah Electric customers;
- new fuel rate and base rate schedules that would apply to the Company's sale of electricity to the current Savannah Electric customers;
- adoption of a "merger transition adjustment" rate that would be used to more closely align Savannah Electric's existing base rates to those of the Company and a "merger transition credit" rate that would credit the additional revenues collected from former Savannah Electric customers to the Company's existing customers; and
- the issuance of additional shares of the Company's common stock to Southern Company in exchange for Southern Company's shares of Savannah Electric common stock.

Rate Plans

Under the terms of the 2004 Retail Rate Plan, which the Georgia PSC approved in December 2004, the Company's earnings are evaluated against a retail return on common equity (ROE) range of 10.25 percent to 12.25 percent. Two-thirds of any earnings

above 12.25 percent will be applied to rate refunds, with the remaining one-third retained by the Company. Retail rates were increased by approximately $194 million and customer fees by approximately $9 million effective January 1, 2005 to cover the higher costs of purchased power; operating and maintenance expenses; environmental compliance; and continued investment in new generation, transmission, and distribution facilities to support growth and ensure reliability. In 2005, the Company recorded $2.7 million in revenue subject to refund related to earnings in excess of 12.25 percent retail ROE.

The Company is required to file a general rate case by July 1, 2007, in response to which the Georgia PSC would be expected to determine whether the rate order should be continued, modified, or discontinued. Until then, the Company may not file for a general base rate increase unless its projected retail ROE falls below 10.25 percent.

Under the 2001 Retail Rate Plan, retail rates were decreased by $118 million effective January 1, 2002. Under the terms of the 2001 Retail Rate Plan, earnings were evaluated against a retail ROE range of 10 percent to 12.95 percent. Two-thirds of any earnings above the 12.95 percent return were to be applied to rate refunds, with the remaining one-third retained by the Company. The Company's earnings in 2004, 2003, and 2002 were within the retail ROE range.

Under the 2001 Retail Rate Plan, the Company discontinued recording accelerated depreciation and amortization and began amortizing the accumulated balance equally over three years as a credit to expense beginning in 2002. Also, the 2001 Retail Rate Plan required the Company to recognize capacity and operating and maintenance costs related to new Georgia PSC-certified PPAs evenly in rates over a three-year period ended December 31, 2004.

Fuel Hedging Program

In 2003, the Georgia PSC approved an order allowing the Company to implement a natural gas and oil procurement and hedging program. This order allows the Company to use financial instruments to hedge price and commodity risk associated with these fuels. 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 the Company retaining 25 percent of the total net gains. In 2005, the Company had a total net gain of $64.1 million, of which the Company retained $16 million.

Fuel Cost Recovery

On May 17, 2005, the Georgia PSC approved the Company's request to increase customer fuel rates by approximately 9.5 percent to recover under recovered fuel costs of approximately $508 million existing as of May 31, 2005 over a four-year period that began June 1, 2005. Based on the order, a portion of the under recovered regulatory clause revenues was reclassified from current assets to deferred charges and other assets in the balance sheet. Under recovered fuel amounts for the periods subsequent to June 1, 2005 totaled $327.5 million through December 31, 2005. The Georgia PSC's order instructs that such amounts be reviewed semi-annually beginning February 2006. If the amount under or over recovered exceeds $50 million at the evaluation date, the Company would be required to file for a temporary fuel rate change. In addition, Savannah Electric's under recovered fuel costs totaled $77.7 million at December 31, 2005. In accordance with the Georgia PSC order, Savannah Electric was scheduled to file an additional request for a fuel cost recovery increase in January 2006. The Company has agreed with a Georgia PSC staff recommendation to forego the temporary fuel rate process, and Savannah Electric has postponed its scheduled filing. Instead, the Company and Savannah Electric will file a combined request in March 2006 to increase the Company's fuel cost recovery rate.

The case will seek approval of a fuel cost recovery rate based upon future fuel cost projections for the combined Company and Savannah Electric generating fleet as well as the under recovered fuel balances existing at June 30, 2006. The new fuel cost recovery rate would be billed beginning in July 2006 to all of the Company's customers, including the existing Savannah Electric customers. Under recovered amounts as of the date of the Merger will be paid by the appropriate customer groups.

In August 2005, the Georgia PSC initiated an investigation of Savannah Electric's fuel practices. In February 2006, an investigation of the Company's fuel

practices was initiated. The Company and Savannah Electric are responding to data requests and cooperating in the investigations. The final outcome of this matter cannot now be determined.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable cost and amounts billed in current regulated rates. Accordingly, any increase in the billing factor would have no significant effect on the Company's revenues or net income, but would increase annual cash flow.

Nuclear Performance Standards

Through December 2004, the Georgia PSC had adopted a three-year performance standard for the Company's nuclear generating units. The performance standard was 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. For the period 2002-2004, the Company's performance fell within the criteria prescribed by the Georgia PSC; there was no associated award or penalty. Effective January 1, 2005, the Georgia PSC discontinued the nuclear performance standard.

Plant McIntosh Construction Project

In December 2002 after a competitive bidding process, the Georgia PSC certified PPAs between Southern Power and the Company and Savannah Electric for capacity from Plant McIntosh Units 10 and 11, construction of which was completed in June 2005. In April 2003, Southern Power applied for FERC approval of these PPAs. In July 2003, the FERC accepted the PPAs to become effective June 1, 2005, subject to refund, and ordered that hearings be held. Intervenors opposed the FERC's acceptance of the PPAs, alleging that they did not meet the applicable standards for market-based rates between affiliates. To ensure the timely completion of the Plant McIntosh construction project and the availability of the units in the summer of 2005 for their retail customers, in May 2004, the Company and Savannah Electric requested the Georgia PSC to direct them to acquire the Plant McIntosh construction project. The Georgia PSC issued such an order and the transfer occurred on May 24, 2004 at a total cost of approximately $415 million, including approximately $14 million of transmission interconnection facilities. Subsequently, Southern Power filed a request to withdraw the PPAs and to terminate the ongoing FERC proceedings. In August 2004, the FERC issued a notice accepting the request to withdraw the PPAs and permitting such request to become effective by operation of law. However, the FERC made no determination on what additional steps may need to be taken with respect to testimony provided in the proceedings. See "FERC Matters – Intercompany Interchange Contract" herein for additional information.

In connection with the 2004 Retail Rate Plan, the Georgia PSC approved the transfer of the Plant McIntosh construction project at a total fair market value of approximately $385 million. This value reflected an approximate $16 million disallowance, of which $13 million was attributable to the Company, and reduced the Company's net income by approximately $8 million. The Georgia PSC also certified a total completion cost not to exceed $547 million for the project. In June 2005, Plant McIntosh Units 10 and 11 were placed into service at a total cost that did not exceed the certified amount. Under the 2004 Retail Rate Plan, the Plant McIntosh revenue requirements impact is being reflected in the Company's rates evenly over the three years ending 2007. See "Retail Regulatory Matters—Rate Plans" herein for additional information regarding the transfer of the Plant McIntosh construction project.

4. JOINT OWNERSHIP AGREEMENTS

The Company and an affiliate, Alabama Power, own equally all of the outstanding capital stock of SEGCO which owns electric generating units with a total rated capacity of 1,020 megawatts, as well as associated transmission facilities. The capacity of 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:

	2005	2004	2003
		(in millions)	
Energy	$54	$51	$55
Capacity	38	36	34
Total	$92	$87	$89

The Company 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 (MEAG), the city of Dalton, Georgia, Florida Power & Light Company, Jacksonville Electric Authority, and Gulf Power. Under these agreements, the Company has contracted to operate and maintain the plants as agent for the co-owners and 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 combustion- turbine common facilities and Plant McIntosh combined cycle units with Savannah Electric who operates the plants. The Company and Progress Energy Florida, Inc. jointly own a combustion turbine unit (Intercession City) operated by Progress Energy Florida, Inc.

At December 31, 2005, 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%	$3,311*	$1,809
Plant Hatch (nuclear)	50.1	935	492
Plant Wansley (coal)	53.5	395	172
Plant Scherer (coal)			
Units 1 and 2	8.4	115	56
Unit 3	75.0	562	270
Plant McIntosh CC (combined cycle)	83.9	436	7
Plant McIntosh Common Facilities (combustion-turbine)	75.0	27	5
Rocky Mountain (pumped storage)	25.4	169*	92
Intercession City (combustion-turbine)	33.3	12	2

*Investment includes write-offs

At December 31, 2005, the portion of total construction work in progress related to Plants Wansley, Scherer, and Rocky Mountain was $8.3 million, $0.5 million, and $0.1 million, respectively, primarily for environmental projects.

The Company's proportionate share of its plant operating expenses is included in the corresponding operating expenses in the statements of income.

5. INCOME TAXES

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

In 2004, in order to avoid the loss of certain federal income tax credits related to the production of synthetic fuel, Southern Company chose to defer certain

deductions otherwise available to the subsidiaries. The cash flow benefit associated with the utilization of the tax credits was allocated to the subsidiary that otherwise would have claimed the available deductions on a separate company basis without the deferral. This allocation concurrently reduced the tax benefit of the credits allocated to those subsidiaries that generated the credits. As the deferred expenses are deducted, the benefit of the tax credits will be repaid to the subsidiaries that generated the tax credits. The Company has recorded $10 million payable to these subsidiaries in Accumulated Deferred Income Taxes on the balance sheets at December 31, 2005.

The transfer of the Plant McIntosh construction project from Southern Power to the Company resulted in a deferred gain to Southern Power for federal income tax purposes. The Company will reimburse Southern Power for the remaining balance of the related deferred taxes of $5.3 million reflected in Southern Power's future taxable income. $3.7 million of this payable to Southern Power is included in Other Deferred Credits and $1.6 million is included in Affiliated Accounts Payable in the balance sheet at December 31, 2005.

The transfer of the Dahlberg, Wansley, and Franklin projects to Southern Power from the Company in 2001 and 2002 also resulted in a deferred gain for federal income tax purposes. Southern Power will reimburse the Company for the remaining balance of the related deferred taxes of $12.2 million reflected in the Company's future taxable income. $10.8 million of this receivable from Southern Power is included in Other Deferred Debits and $1.4 million is included in Affiliated Accounts Receivable in the balance sheet at December 31, 2005.

At December 31, 2005, tax-related regulatory assets were $501 million and tax-related regulatory liabilities were $159 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:

	2005	2004	2003
Total provision for income taxes:		(in millions)	
Federal:			
Current	**$173**	$116	$143
Deferred	**203**	221	181
	376	337	324
State:			
Current	**26**	12	24
Deferred	**29**	30	16
Deferred investment tax credits	**-**	-	2
Total	**$431**	$379	$366

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:

	2005	2004
	(in millions)	
Deferred tax liabilities:		
Accelerated depreciation	**$2,177**	$2,050
Property basis differences	**558**	577
Employee benefit obligations	**163**	149
Fuel clause under recovery	**305**	141
Premium on reacquired debt	**69**	72
Storm damage reserve	**13**	6
Other	**74**	81
Total	**3,359**	3,076
Deferred tax assets:		
Federal effect of state deferred taxes	**116**	106
Other property basis differences	**139**	147
Other deferred costs	**126**	94
Employee benefit obligations	**51**	55
Other comprehensive income	**23**	22
Unbilled revenue	**13**	11
Other	**33**	19
Total	**501**	454
Total deferred tax liabilities, net	**2,858**	2,622
Portion included in current (liabilities) assets, net	**(128)**	(66)
Accumulated deferred income taxes in the balance sheets	**$2,730**	$2,556

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 2005, $12 million in 2004, and $15 million in 2003. At December 31, 2005, all investment tax credits available to reduce federal income taxes payable had been utilized.

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

	2005	2004	2003
Federal statutory rate	35%	35%	35%
State income tax, net of federal deduction	3	3	3
Non-deductible book depreciation	1	1	1
Other	(1)	(2)	(2)
Effective income tax rate	38%	37%	37%

6. FINANCING

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

The Company has formed certain wholly owned trust subsidiaries for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the Company through the issuance of junior subordinated notes totaling $969 million, which constitute substantially all of the assets of the trusts and are reflected in the balance sheets as Long-Term Debt Payable to Affiliated Trusts. The Company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the respective trusts' payment obligations with respect to these securities. At December 31, 2005, preferred securities of $940 million were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for these trusts and the related securities.

Securities Due Within One Year

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

	2005	2004
	(in millions)	
Capital lease	$ 3	$ 2
Senior notes	150	450
Preferred stock	15	-
Total	$168	$452

Serial maturities through 2010 applicable to total long-term debt and preferred stock are as follows: $168 million in 2006; $303 million in 2007; $3 million in 2008; $278 million in 2009; and $4 million in 2010.

Pollution Control Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such 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, 2005 was $1.7 billion.

Senior Notes

The Company issued a total of $625 million of unsecured senior notes in 2005. The proceeds of these issues were used to redeem or repay at maturity long-term debt, to repay short-term indebtedness, and for other general corporate purposes. At December 31, 2005 and 2004, the Company had $2.6 billion and $2.4 billion of senior notes outstanding, respectively. These senior notes are subordinate to all secured debt of the Company.

Capital Leases

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, 2005 and 2004, the Company had a capitalized lease obligation for its corporate headquarters

building of $74 million and $77 million, respectively, with an interest rate of 8.1 percent. For ratemaking purposes, the Georgia PSC 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 Georgia PSC. See Note 1 under "Regulatory Assets and Liabilities."

Bank Credit Arrangements

At the beginning of 2006, the Company had credit arrangements with banks totaling $780 million, of which $778 million was unused. Of these facilities, $70 million expires at various times throughout 2006; $350 million expires in 2007, with the remaining $360 million expiring in 2010. The facilities that expire in 2006 provide the option of converting borrowings into a two-year term loan. The Company expects to renew its facilities, as needed, prior to expiration. The agreements contain stated borrowing rates. All the agreements require payment of commitment fees based on the unused portion 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. A fee is also paid to the agent bank.

The credit arrangements contain covenants that limit the level of indebtedness to capitalization to 65 percent, as defined in the arrangements. For purposes of these definitions, indebtedness excludes the long-term debt payable to affiliated trusts. In addition, the credit arrangements contain cross default provisions that would trigger an event of default if the Company defaulted on other indebtedness above a specified threshold. At December 31, 2005, the Company was in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowings.

The $778 million 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, 2005 was $106 million. In addition, the Company borrows under a commercial paper program and an extendible commercial note program. The amount of commercial paper outstanding at December 31, 2005 was $268 million. The amount of commercial paper outstanding at December 31, 2004 was $208 million. There were no outstanding extendible commercial notes at December 31, 2005. Commercial paper is included in notes payable on the balance sheets.

During 2005, the peak amount of short-term debt outstanding was $549 million and the average amount outstanding was $242 million. The average annual interest rate on short-term debt in 2005 was 3.20 percent.

Financial Instruments

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. See Note 3 under "Retail Regulatory Matters – Fuel Hedging Program" for information on the Company's fuel hedging program. The Company also enters into hedges of forward electricity sales. There was no material ineffectiveness recorded in earnings in 2005, 2004, and 2003.

At December 31, 2005, the fair value of derivative energy contracts was reflected in the financial statements as follows:

	Amounts (in thousands)
Regulatory liabilities, net	$26,643
Other comprehensive income	-
Net income	(81)
Total fair value	$26,562

The fair value gain or loss for hedges that are recoverable through the regulatory fuel clauses are recorded in regulatory assets and liabilities and are recognized in earnings at the same time the hedged items affect earnings. The Company has energy-related hedges in place up to and including 2008.

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

addition to interest rate swaps, the Company has also entered into certain options agreements that effectively cap its interest rate exposure in return for payment of a premium. In some cases, costless collars have been used that effectively establish a floor and a ceiling to interest rate expense.

At December 31, 2005, the Company had $1.0 billion notional amounts of interest derivatives accounted for as cash flow hedges outstanding with net fair value gains as follows:

Maturity	Weighted Average Fixed Rate Paid	Notional Amount	Fair Value Gain / (Loss)
		(in millions)	
2007	2.67%	$300	$ 2.4
2006-2007	2.09% -3.85%*	$400	$ 1.2
2037	4.58% -5.75%**	$300	$(1.1)

*Series of interest rate caps and collars (showing the lowest floor and highest cap) with variable rate based on one-month LIBOR
**Interest rate collar

The fair value gain or loss for cash flow hedges is recorded in other comprehensive income and is reclassified into earnings at the same time the hedged items affect earnings. In 2005, 2004, and 2003, the Company settled gains (losses) totaling $0.9 million, $(12.4) million, and $(11.3) million, respectively, upon termination of certain interest derivatives at the same time it issued debt. For the years 2005, 2004, and 2003, approximately $1.9 million, $3.9 million, and $3.4 million, respectively, of pre-tax losses were reclassified from other comprehensive income to interest expense. For 2006, pre-tax losses of approximately $0.5 million are expected to be reclassified from other comprehensive income to interest expense. The Company has gains/losses that are being amortized through 2017.

7. COMMITMENTS

Construction Program

The Company currently estimates property additions to be approximately $1.3 billion, $1.4 billion, and $1.3 billion in 2006, 2007, and 2008, respectively. These amounts include $44 million, $28 million, and $14 million in 2006, 2007, and 2008, respectively, for construction expenditures related to contractual purchase commitments for uranium and nuclear fuel conversion, enrichment, and fabrication services included under "Fuel Commitments" herein. 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, changes in FERC rules and transmission regulations, 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, 2005, significant purchase commitments were outstanding in connection with the construction program.

The Company completed construction of Plant McIntosh Units 10 and 11 in June 2005 and has no other generating plants currently under construction. Construction related to new transmission and distribution facilities and capital improvements to existing generation, transmission and distribution facilities, including those needed to meet environmental standards, is ongoing.

Long-Term Service Agreements

The Company and Savannah Electric have entered into a Long-Term Service Agreement (LTSA) with General Electric (GE) for the purpose of securing maintenance support for the combustion turbines at the Plant McIntosh combined cycle facility. In summary, the LTSA stipulates that GE will perform all planned inspections on the covered equipment, which includes the cost of all labor and materials. GE is also obligated to cover the costs of unplanned maintenance on the covered equipment subject to a limit specified in each contract.

In general, this LTSA is in effect through two major inspection cycles per unit. Scheduled payments to GE are made at various intervals based on actual operating hours of the respective units. Total payments to GE under this agreement are currently estimated at $186 million over the remaining term of the agreement, which may range up to 30 years. However, the LTSA contains various cancellation provisions at the option of the Company.

The Company has also entered into an LTSA with GE through 2014 for neutron monitoring system parts and electronics at Plant Hatch. Total remaining payments to GE under this agreement are currently estimated at $13.1 million. The contract contains

cancellation provisions at the option of the Company.

Payments made to GE prior to the performance of any work are recorded as a prepayment in the balance sheets. Work performed by GE is capitalized or charged to expense as appropriate net of any joint owner billings, based on the nature of the work.

Fuel Commitments

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement of fossil and nuclear fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Coal commitments include forward contract purchases for sulfur dioxide emission allowances. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery. Amounts included in the chart below represent estimates based on New York Mercantile Exchange future prices at December 31, 2005.

Total estimated minimum long-term obligations at December 31, 2005 were as follows:

	Commitments		
	Natural Gas	Coal	Nuclear Fuel
		(in millions)	
2006	$577	$1,579	$ 44
2007	325	1,313	28
2008	200	907	14
2009	257	422	11
2010	254	272	14
2011 and thereafter	2,047	40	64
Total	$3,660	$4,533	$175

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

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other Southern Company retail operating companies, Southern Power, and Southern Company Gas. Under these agreements, each of the retail operating companies, Southern Power, and Southern Company Gas may be jointly and severally liable. The creditworthiness of Southern Power and Southern Company Gas is currently inferior to the creditworthiness of the retail operating companies. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the retail 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 Company Gas as a contracting party under these agreements.

Purchased Power Commitments

The Company has commitments regarding a portion of a 5 percent interest in Plant Vogtle owned by 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 $54 million, $55 million, and $57 million in 2005, 2004, and 2003, respectively. The current projected Plant Vogtle capacity payments are:

	Capacity Payments
	(in millions)
2006	$ 53
2007	52
2008	54
2009	54
2010	54
2011 and thereafter	261
Total	$528

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 at the time of the disallowance was written off.

The Company has entered into other various long-term commitments for the purchase of electricity. Estimated total long-term obligations under these

commitments at December 31, 2005 were as follows:

	Commitments	
	Affiliated	Non-Affiliated
	(in millions)	
2006	$205	$85
2007	205	86
2008	205	87
2009	205	68
2010	112	66
2011 and thereafter	455	278
Total	$1,387	$670

Operating Leases

The Company has entered into various operating leases with various terms and expiration dates. Rental expenses related to these operating leases totaled $38 million for 2005, $38 million for 2004, and $36 million for 2003.

At December 31, 2005, estimated minimum lease payments for these noncancelable operating leases were as follows:

	Minimum Lease Payments		
	Rail Cars	Other	Total
		(in millions)	
2006	$ 17	$ 17	$ 34
2007	17	14	31
2008	16	11	27
2009	15	9	24
2010	14	6	20
2011 and thereafter	48	10	58
Total	$127	$67	$194

In addition to the rental commitments above, the Company has obligations upon expiration of certain rail car leases with respect to the residual value of the leased property. These leases expire in 2011 and the Company's maximum obligation is $68 million. 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 rail car lease obligations is shared with the joint owners of plants Scherer and Wansley. Rental expenses related to the rail car leases are fully recoverable through the fuel cost recovery clause as ordered by the Georgia PSC.

Guarantees

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. Alabama Power has also guaranteed $50 million in senior notes issued by SEGCO. The Company has agreed to reimburse Alabama Power for the pro rata portion of such obligations corresponding to the Company'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.

8. STOCK OPTION PLAN

Southern Company provides non-qualified stock options to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2005, 1,551 current and former employees of the Company participated in the stock option plan. The maximum number of shares of Southern Company common stock that may be issued under this plan may not exceed 55 million. The prices of options granted to date have been at the fair market value of the shares on the dates of grant. Options granted to date become exercisable pro rata over a maximum period of three years from the date of grant. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the stock option plan. Activity from 2003 to 2005 for the options granted

to the Company's employees under the stock option plan is summarized below:

	Shares Subject To Option	Average Option Price Per Share
Balance at December 31, 2002	7,178,597	$19.73
Options granted	1,455,517	27.98
Options canceled	(54,860)	25.47
Options exercised	(1,428,273)	16.92
Balance at December 31, 2003	7,150,981	21.92
Options granted	1,434,915	29.50
Options canceled	(6,371)	25.99
Options exercised	(1,450,309)	18.25
Balance at December 31, 2004	**7,129,216**	**24.19**
Options granted	**1,427,618**	**32.71**
Options canceled	**(12,910)**	**23.75**
Options exercised	**(1,838,033)**	**21.23**
Balance at December 31, 2005	**6,705,891**	**$26.82**

Options exercisable:	
At December 31, 2003	3,956,234
At December 31, 2004	4,304,091
At December 31, 2005	**3,989,722**

The following table summarizes information about options outstanding at December 31, 2005:

	Dollar Price Range of Options		
	13-21	21-28	28-35
Outstanding:			
Shares (in thousands)	991	2,922	2,794
Average remaining life (in years)	4.2	6.0	8.5
Average exercise price	$17.25	$25.94	$31.13
Exercisable:			
Shares (in thousands)	991	2,496	503
Average exercise price	$17.25	$25.59	$29.75

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act, the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the Company's nuclear power plants. The Act provides funds up to $10.76 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 $101 million per incident for each licensed reactor it operates but not more than an aggregate of $15 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 $203 million per incident but not more than an aggregate of $30 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 up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. The Company purchases the maximum limit allowed by NEIL 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 NEIL policies would be $48 million.

Following the terrorist attacks of September 2001, both ANI and NEIL confirmed that terrorist acts against commercial nuclear power plants would, subject to the normal policy limits, be covered under their insurance. Both companies, however, revised their policy terms on

a prospective basis to include an industry aggregate for all "non-certified" terrorist acts i.e., acts that are not certified acts of terrorism pursuant to the Terrorism Risk Insurance Act of 2002, which was renewed in 2005. The aggregate for all NEIL policies, which applies to non-certified property claims stemming from terrorism within a 12-month duration, is $3.24 billion plus any amounts available through reinsurance or indemnity from an outside source. The non-certified ANI nuclear liability cap is a $300 million shared industry aggregate during the normal ANI policy period.

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

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

10. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2005 and 2004 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred Stock
		(in millions)	
March 2005	**$1,370**	**$286**	**$142**
June 2005	**1,459**	**311**	**158**
September 2005	**2,219**	**626**	**355**
December 2005	**1,586**	**165**	**60**
March 2004	$1,199	$285	$144
June 2004	1,353	322	156
September 2004	1,582	486	287
December 2004	1,237	166	71

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

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SELECTED FINANCIAL AND OPERATING DATA 2001-2005

Georgia Power Company 2005 Annual Report

	2005	2004	2003	2002	2001
Operating Revenues (in thousands)	**$6,634,203**	$5,370,808	$4,913,507	$4,822,460	$4,965,794
Net Income after Dividends on Preferred Stock (in thousands)	**$714,999**	$658,001	$630,577	$617,629	$610,335
Cash Dividends on Common Stock (in thousands)	**$556,100**	$565,500	$565,800	$542,900	$527,300
Return on Average Common Equity (percent)	**14.15**	13.95	14.05	13.99	14.12
Total Assets (in thousands)	**$17,047,783**	$15,822,338	$14,850,754	$14,342,656	$14,447,973
Gross Property Additions (in thousands)	**$906,248**	$1,126,064	$742,810	$883,968	$1,389,751
Capitalization (in thousands):					
Common stock equity	**$5,214,535**	$4,890,561	$4,540,211	$4,434,447	$4,397,485
Preferred stock	**-**	14,609	14,569	14,569	14,569
Mandatorily redeemable preferred securities	**-**	-	940,000	940,000	789,250
Long-term debt payable to affiliated trusts	**969,073**	969,073	-	-	-
Long-term debt	**4,179,218**	3,709,852	3,762,333	3,109,619	2,961,726
Total (excluding amounts due within one year)	**$10,362,826**	$9,584,095	$9,257,113	$8,498,635	$8,163,030
Capitalization Ratios (percent):					
Common stock equity	**50.3**	51.0	49.0	52.2	53.9
Preferred stock	**-**	0.2	0.2	0.2	0.2
Mandatorily redeemable preferred securities	**-**	-	10.2	11.1	9.6
Long-term debt payable to affiliated trusts	**9.4**	10.1	-	-	-
Long-term debt	**40.3**	38.7	40.6	36.5	36.3
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Security Ratings:					
Preferred Stock -					
Moody's	**Baa1**	Baa1	Baa1	Baa1	Baa1
Standard and Poor's	**BBB+**	BBB+	BBB+	BBB+	BBB+
Fitch	**A**	A	A	A	A
Unsecured Long-Term Debt -					
Moody's	**A2**	A2	A2	A2	A2
Standard and Poor's	**A**	A	A	A	A
Fitch	**A+**	A+	A+	A+	A+
Customers (year-end):					
Residential	**1,832,520**	1,801,426	1,768,662	1,734,430	1,698,407
Commercial	**270,373**	265,543	258,276	250,993	244,674
Industrial	**8,206**	7,676	7,899	8,240	8,046
Other	**3,536**	3,482	3,434	3,328	3,239
Total	**2,114,635**	2,078,127	2,038,271	1,996,991	1,954,366
Employees (year-end)	**8,713**	8,731	8,714	8,837	9,048

N/A = Not Applicable.

SELECTED FINANCIAL AND OPERATING DATA 2001-2005 (continued)
Georgia Power Company 2005 Annual Report

	2005	2004	2003	2002	2001
Operating Revenues (in thousands):					
Residential	**$ 2,024,204**	$1,736,072	$1,583,082	$1,600,438	$1,507,031
Commercial	**2,206,252**	1,812,096	1,661,054	1,631,130	1,682,918
Industrial	**1,351,731**	1,172,936	1,012,267	1,004,288	1,106,420
Other	**60,625**	55,881	53,569	52,241	52,943
Total retail	**5,642,812**	4,776,985	4,309,972	4,288,097	4,349,312
Sales for resale - non-affiliates	**519,673**	246,545	259,376	270,678	366,085
Sales for resale - affiliates	**264,989**	166,245	174,855	98,323	99,411
Total revenues from sales of electricity	**6,427,474**	5,189,775	4,744,203	4,657,098	4,814,808
Other revenues	**206,729**	181,033	169,304	165,362	150,986
Total	**$6,634,203**	$5,370,808	$4,913,507	$4,822,460	$4,965,794
Kilowatt-Hour Sales (in thousands):					
Residential	**23,585,115**	22,930,372	21,778,582	22,144,559	20,119,080
Commercial	**29,768,402**	28,014,357	26,940,572	26,954,922	26,493,255
Industrial	**25,027,371**	26,357,271	25,703,421	25,739,785	25,349,477
Other	**601,330**	602,202	595,742	593,202	583,007
Total retail	**78,982,218**	77,904,202	75,018,317	75,432,468	72,544,819
Sales for resale - non-affiliates	**11,234,527**	5,969,983	8,835,804	8,069,375	8,110,096
Sales for resale - affiliates	**4,854,914**	4,782,873	5,844,196	3,962,559	3,133,485
Total	**95,071,659**	88,657,058	89,698,317	87,464,402	83,788,400
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**8.58**	7.57	7.27	7.23	7.49
Commercial	**7.41**	6.47	6.17	6.05	6.35
Industrial	**5.40**	4.45	3.94	3.90	4.36
Total retail	**7.14**	6.13	5.75	5.68	6.00
Sales for resale	**4.88**	3.84	2.96	3.07	4.14
Total sales	**6.76**	5.85	5.29	5.32	5.75
Residential Average Annual Kilowatt-Hour Use Per Customer	**12,974**	12,838	12,421	12,867	11,933
Residential Average Annual Revenue Per Customer	**$1,113**	$972	$903	$930	$894
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**15,097**	13,978	13,980	14,059	14,474
Maximum Peak-Hour Demand (megawatts):					
Winter	**13,501**	12,208	13,153	11,873	11,977
Summer	**15,953**	15,180	14,826	14,597	14,294
Annual Load Factor (percent)	**59.7**	61.5	61.0	60.4	61.7
Plant Availability (percent):					
Fossil-steam	**90.7**	90.3	87.6	80.9	88.5
Nuclear	**89.3**	94.8	94.2	88.8	94.4
Source of Energy Supply (percent):					
Coal	**60.8**	57.9	58.6	59.5	58.5
Nuclear	**15.1**	17.3	16.8	16.2	18.1
Hydro	**1.9**	1.5	2.1	0.9	1.1
Oil and gas	**2.9**	0.1	0.3	0.3	0.4
Purchased power -					
From non-affiliates	**5.7**	7.0	7.5	6.3	7.8
From affiliates	**13.6**	16.2	14.7	16.8	14.1
Total	**100.0**	100.0	100.0	100.0	100.0

DIRECTORS AND OFFICERS
Georgia Power Company 2005 Annual Report

Directors

Juanita Powell Baranco
Executive Vice President
Baranco Acura
(Resigned effective 2/21/2006)

Gus H. Bell, III – *Nominee*
Chairman, President and Chief Executive Officer
Hussey, Gay, Bell and DeYoung - A Bell Company

Robert L. Brown, Jr.
President and Chief Executive Officer
R. L. Brown & Associates, Inc.

Ronald D. Brown
President and Chief Executive Officer
Atlanta Life Financial Group

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

Michael D. Garrett
President and Chief Executive Officer
Georgia Power Company

David M. Ratcliffe
President and Chief Executive Officer
The Southern Company

D. Gary Thompson
Retired from
Wachovia Corporation

Richard W. Ussery
Retired from
Total System Services (TSYS)

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

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

Officers

Michael D. Garrett
President and Chief Executive Officer
Georgia Power Company

William C. Archer, III
Executive Vice President
External Affairs
(Retirement effective 3/19/2006)

Mickey A. Brown
Executive Vice President
Customer Service Organization

Cliff S. Thrasher
Executive Vice President, Chief Financial Officer
and Treasurer

Christopher C. Womack
Executive Vice President (Effective 3/11/2006)
External Affairs

Judy M. Anderson
Senior Vice President
Charitable Giving

Richard L. Holmes
Senior Vice President
Metro Region

E. Lamont Houston
Senior Vice President (Effective 1/14/2006)
Customer Service and Sales

Douglas E. Jones
Senior Vice President (Effective 3/11/2006)
Fossil and Hydro Generation

James H. Miller III
Senior Vice President and
General Counsel

Leslie R. Sibert
Vice President
Transmission

Gene L. Ussery
Vice President
Distribution

DIRECTORS AND OFFICERS

Georgia Power Company 2005 Annual Report

Michael K. Anderson
Vice President (Effective 1/14/2006)
Corporate Services

W. Craig Barrs
Vice President

Robert A. Bell
Vice President (Effective 2/15/2006)
Human Resources

Rebecca A. Blalock
Vice President
Information Technology

P. Mike Clanton
Vice President (Effective 1/14/2006)
Customer Service

Ann P. Daiss
Vice President, Comptroller and
Chief Accounting Officer (Effective 3/11/2006)

Walter Dukes
Region Vice President
East

A. Bryan Fletcher
Vice President
Supply Chain Management

J. Kevin Fletcher
Vice President
Community and Economic Development

Jeff G. Franklin
Region Vice President
Northwest

Oscar C. Harper IV
Vice President (Effective 2/11/2006)
Resource Planning and Nuclear Development

O. Ben Harris
Vice President
Land

W. Ron Hinson
Vice President, Comptroller and
Chief Accounting Officer (Resigned effective
3/11/2006)

Ed F. Holcombe
Vice President
Governmental and Regulatory Affairs

Charles H. Huling
Vice President
Environmental Affairs

Anne H. Kaiser
Vice President
Sales

Ellen N. Lindemann
Vice President (Resigned effective 2/1/2006)
Human Resources

Jacki W. Lowe
Region Vice President
West

Daniel M. Lowery
Corporate Secretary

Terri H. Lupo
Region Vice President
South

Frank J. McCloskey
Vice President
Diversity

Robert B. Morris
Assistant Comptroller and Assistant Secretary

James E. Sykes, Jr.
Region Vice President
Northeast

Mark K. Tate
Assistant Comptroller

Jeff L. Wallace
Vice President (Resigned effective 2/11/2006)
Planning and Utility Relations

Thomas J. Wicker
Region Vice President
Central

W. Tal Wright
Vice President
Corporate Communication

Wayne Boston
Assistant Secretary and
Assistant Treasurer

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

Profile
The Company produces and delivers electricity as an integrated utility to retail customers within the State of Georgia and to wholesale customers in the Southeast. The Company sells electricity to approximately 2.1 million customers within its service area of approximately 57,000 square miles. In 2005, retail energy sales accounted for 83 percent of the Company's total sales of 95.1 billion kilowatt-hours.

The Company is a wholly owned subsidiary of The Southern Company, which is the parent company of five retail operating companies and a wholesale generation subsidiary, as well as other direct and indirect subsidiaries. There is no established public trading market for the Company's common stock.

Trustee, Registrar and Interest Paying Agent
All series of Senior Notes and Trust Preferred Securities
JPMorgan Chase Bank, N.A.
Institutional Trust Services
4 New York Plaza, 15th Floor
New York, NY 10004

Number of Preferred Shareholders of record as of December 31, 2005, was 1,003.

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

Georgia Power Company
241 Ralph McGill Boulevard, N.E.
Atlanta, GA 30308-3374
(404) 506-6526

Auditors
Deloitte & Touche LLP
Suite 1500
191 Peachtree Street, N.E.
Atlanta, GA 30303

Legal Counsel
Troutman Sanders LLP
600 Peachtree Street, N.E.
Suite 5200
Atlanta, GA 30308

GEORGIA POWER
A SOUTHERN COMPANY

July 28, 2006

Docket Nos.: 50-321 50-424
50-366 50-425
72-36

NL-06-1486

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
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 2005.

2. A set of quarterly financial statements for the period ending June 30, 2006.

3. A one year projected Cash Flows Statement for period January 1, 2007, through December 31, 2007.

Should you have any questions in connection with our response, please contact me at (404) 506-7952 or Jan Miller at (404) 506-6690. This letter contains no NRC commitments.

Sincerely,

Robert A. Aubuchon

Enclosures

cc: Southern Nuclear Operating Company
Mr. J. T. Gasser, Executive Vice President
Mr. L. M. Stinson, Vice President, Plant Hatch
Mr. D. E. Grissette, Vice President, Plant Vogtle
Mr. D. R. Madison, General Manager – Plant Hatch
Mr. T. E. Tynan, General Manager – Plant Vogtle
RType: CHA02.004; CVC7000

U. S. Nuclear Regulatory Commission
Dr. W. D. Travers, Regional Administrator
Mr. C. Gratton, NRR Project Manager – Hatch
Mr. C. Gratton, NRR Project Manager – Vogtle
Mr. D. S. Simpkins, Senior Resident Inspector – Hatch
Mr. G. J. McCoy, Senior Resident Inspector – Vogtle

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2006	2005	2006	2005
OPERATING REVENUES:				
Retail sales	$1,420,762	$1,227,087	$2,687,718	$2,412,323
Sales for resale--				
Non-affiliates	132,557	126,000	265,921	238,852
Affiliates	85,674	54,743	120,616	80,374
Other revenues	59,745	51,358	111,932	98,069
Total operating revenues	1,698,738	1,459,188	3,186,187	2,829,618
OPERATING EXPENSES:				
Operation--				
Fuel	556,691	412,050	991,465	721,316
Purchased power--				
Non-affiliates	82,321	64,523	138,876	117,497
Affiliates	145,518	140,800	336,037	360,804
Other	226,256	223,471	444,976	425,550
Maintenance	119,876	123,575	239,176	240,225
Depreciation and amortization	117,590	124,999	235,447	248,099
Taxes other than income taxes	68,945	58,648	136,090	119,407
Total operating expenses	1,317,197	1,148,066	2,522,067	2,232,898
OPERATING INCOME	381,541	311,122	664,120	596,720
OTHER INCOME (EXPENSE):				
Allowance for equity funds used during construction	6,338	7,935	12,123	17,192
Interest income	199	31	515	502
Interest expense, net of amounts capitalized	(61,322)	(55,174)	(121,529)	(105,594)
Interest expense to affiliate trusts	(14,877)	(14,877)	(29,755)	(29,755)
Other income (expense), net	3,370	2,821	2,376	(21)
Total other income and (expense)	(66,292)	(59,264)	(136,270)	(117,676)
EARNINGS BEFORE INCOME TAXES	315,249	251,858	527,850	479,044
Income taxes	119,059	94,140	199,003	178,794
NET INCOME	196,190	157,718	328,847	300,250
DIVIDENDS ON PREFERRED STOCK	-	167	1,010	335
NET INCOME AFTER DIVIDENDS ON PREFERRED STOCK	$196,190	$157,551	$327,837	$299,915

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, 2006	At June 30, 2005
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$11,422	$9,294
Receivables --		
Customer accounts receivable	416,118	361,605
Unbilled revenues	176,184	168,392
Under recovered regulatory clause revenue	372,587	153,301
Other accounts and notes receivable	85,136	185,223
Affiliated companies	55,814	31,350
Accumulated provision for uncollectible accounts	(8,521)	(6,575)
Fossil fuel stock, at average cost	262,620	207,959
Materials and supplies, at average cost	352,866	286,446
Other	174,706	91,819
Total Current Assets	1,898,932	1,488,814
PROPERTY, PLANT AND EQUIPMENT:		
In service	19,957,393	19,327,416
Less accumulated provision for depreciation	7,775,166	7,392,744
	12,182,227	11,934,672
Nuclear fuel, at amortized cost	148,604	129,567
Construction work in progress	599,874	443,904
Total Property, Plant and Equipment	12,930,705	12,508,143
OTHER PROPERTY AND INVESTMENTS:		
Equity investments in unconsolidated subsidiaries	68,470	65,949
Nuclear decommissioning trusts	499,868	466,656
Other	70,800	64,472
Total Other Property and Investments	639,138	597,077
DEFERRED CHARGES AND OTHER ASSETS:		
Deferred charges related to income taxes	497,775	506,259
Prepaid pension costs	487,462	460,865
Unamortized debt issuance expense	84,515	88,638
Unamortized loss on reacquired debt	165,650	172,961
Deferred under recovered regulatory clause revenues	477,611	362,692
Other	255,106	170,698
Total Deferred Charges and Other Assets	1,968,119	1,762,113
TOTAL ASSETS	$17,436,894	$16,356,147

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

	At June 30, 2006	At June 30, 2005
LIABILITIES AND STOCKHOLDER'S EQUITY		
CURRENT LIABILITIES:		
Securities due within one year	$2,822	$402,603
Notes payable	657,559	379,902
Accounts payable --		
Affiliated companies	207,585	157,765
Other	292,313	248,786
Customer deposits	140,292	122,446
Taxes accrued		
Income taxes	313,302	183,985
Other	146,254	115,596
Interest accrued	74,533	78,595
Vacation pay accrued	45,692	44,179
Other	210,770	186,640
Total Current Liabilities	2,091,122	1,920,497
LONG-TERM DEBT	4,177,916	3,931,825
LONG-TERM DEBT PAYABLE TO AFFILIATED TRUSTS	969,073	969,073
DEFERRED CREDITS AND OTHER LIABILITIES:		
Accumulated deferred income taxes	2,693,006	2,598,783
Deferred credits related to income taxes	153,196	164,588
Accumulated deferred investment tax credits	281,581	293,872
Employee benefits provisions	379,656	346,916
Asset retirement obligations	647,003	520,298
Other	548,023	581,077
Total Deferred Credits and Other Liabilities	4,702,465	4,505,534
PREFERRED STOCK	-	14,609
COMMON STOCKHOLDER'S EQUITY:		
Common stock	344,250	344,250
Paid-in capital	2,880,563	2,589,121
Retained earnings	2,288,285	2,124,641
Accumulated other comprehensive income	(16,780)	(43,403)
Total Common Stockholder's Equity	5,496,318	5,014,609
TOTAL LIABILITIES AND STOCKHOLDER'S EQUITY	$17,436,894	$16,356,147

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

	FOR THE SIX MONTHS ENDED JUNE 2006	2005
OPERATING ACTIVITIES:		
Net income	$328,847	$300,250
Adjustments to reconcile net income to net cash provided by operating activities --		
Depreciation and amortization	276,048	292,447
Deferred income taxes and investment tax credits, net	13,433	89,724
Deferred expenses - affiliated	18,717	20,302
Allowance for funds used during construction	(12,123)	(17,192)
Pension, postretirement, and other employee benefits	(1,225)	5,318
Stock option expense	4,330	-
Other, net	8,729	(1,058)
Changes in certain current assets and liabilities --		
Receivables, net	(89,773)	(247,991)
Fossil fuel stock	(80,881)	(23,692)
Materials and supplies	(28,885)	(16,024)
Other current assets	49,999	14,055
Accounts payable	(128,890)	(59,236)
Taxes accrued	38,209	43,098
Other current liabilities	(76,833)	(42,595)
NET CASH PROVIDED FROM OPERATING ACTIVITIES	319,702	357,406
INVESTING ACTIVITIES:		
Gross property additions	(448,857)	(381,191)
Nuclear decommissioning trust fund purchases	(241,021)	(205,261)
Nuclear decommissioning trust fund sales	234,141	196,562
Cost of removal net of salvage	(10,658)	(10,359)
Other	(9,099)	(33,274)
NET CASH USED FOR INVESTING ACTIVITIES	(475,494)	(433,523)
FINANCING ACTIVITIES:		
Increase (decrease) in notes payable, net	389,817	171,669
Proceeds --		
Senior notes	-	375,000
Pollution control bonds	10,125	185,000
Capital contributions from parent company	232,328	100,000
Gross excess tax benefit of stock options	611	-
Redemptions --		
Pollution control bonds	(10,125)	(85,000)
Senior notes	(150,000)	(300,000)
Preferred stock	(14,569)	
Special deposits - redemption funds	-	(100,000)
Payment of preferred stock dividends	(12)	(211)
Payment of common stock dividends	(301,250)	(278,050)
Other	(347)	(16,494)
NET CASH PROVIDED FROM FINANCING ACTIVITIES	156,578	51,914
NET CHANGE IN CASH AND CASH EQUIVALENTS	786	(24,203)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	10,636	33,497
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$11,422	$9,294

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

GEORGIA POWER COMPANY
PROJECTED STATEMENT OF CASH FLOWS
2007 FORECAST
(Stated in Thousands of Dollars)

	2007 FORECAST
OPERATING ACTIVITIES	
Net income before preferred dividends	$831,346
Principal noncash items-	
Depreciation and amortization	622,394
Deferred income taxes, net	(26,943)
Allowance for equity funds used during construction	(71,263)
Pension, postretirement and other employee benefits	(16,032)
Other, net	230,590
Change in current assets & liabilities-	
Receivables	(36,755)
Inventories	10,331
Accounts payable	9,114
Other current assets and liabilities	95,611
NET CASH PROVIDED FROM OPERATING ACTIVITIES	1,648,393
INVESTING ACTIVITIES	
Gross property additions	(1,485,481)
Cost of removal, net of salvage	(34,695)
Allowance for equity funds used during construction	71,263
Other property and investments	(6,514)
NET CASH USED FOR INVESTING ACTIVITIES	(1,455,427)
FINANCING ACTIVITIES	
Increase in notes payable, net	(8,860)
Proceeds -	
Senior notes	675,000
Preferred stock	300,000
Capital contributions from parent company	126,619
Redemptions -	
Senior notes	(300,000)
Trust preferred securities	(300,000)
Capitalized leases	(2,550)
Stock Option Expense	12,399
Payment of preferred stock dividends	(3,370)
Payment of common stock dividends	(678,100)
Other	(13,702)
NET CASH USED FOR FINANCING ACTIVITIES	(192,564)
NET INC (DEC) IN CASH AND TEMPORARY CASH INVESTMENTS	$402
CASH AND TEMPORARY CASH INVESTMENTS AT BEG OF PERIOD	$15,750
CASH AND TEMPORARY CASH INVESTMENTS AT END OF PERIOD	$16,152

2005 *Annual Report*

GEORGIA POWER COMPANY

GEORGIA POWER

A SOUTHERN COMPANY

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Georgia Power Company 2005 Annual Report

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SUMMARY

	2005	2004	Percent Change
Financial Highlights *(in millions):*			
Operating revenues	**$6,634**	$5,371	23.5
Operating expenses	**$5,246**	$4,112	27.6
Net income after dividends on preferred stock	**$715**	$658	8.7
Operating Data:			
Kilowatt-hour sales *(in millions):*			
Retail	**78,982**	77,904	1.4
Sales for resale - non-affiliates	**11,235**	5,970	88.2
Sales for resale - affiliates	**4,855**	4,783	1.5
Total	**95,072**	88,657	7.2
Customers served at year-end *(in thousands)*	**2,115**	2,078	1.8
Peak-hour demand *(in megawatts)*	**15,953**	15,180	5.1
Capitalization Ratios *(percent):*			
Common stock equity	**50.3**	51.0	
Preferred stock	**-**	0.2	
Long-term debt payable to affiliated trusts	**9.4**	10.1	
Long-term debt	**40.3**	38.7	
Return on Average Common Equity *(percent)*	**14.15**	13.95	
Ratio of Earnings to Fixed Charges *(times)*	**4.92**	5.11	

LETTER TO INVESTORS

Georgia Power 2005 Annual Report

Georgia Power employees' extraordinary response after Hurricane Katrina and other storms hit the Gulf Coast last year is just one of the highlights in what was a remarkable year for the company.

Whether we're responding to storms in our own back yard or to the needs of fellow Southern Company employees and customers, it's extensive pre-planning and excellent execution that makes us so successful – it really is what we do best.

That's why we were honored when the Edison Electric Institute recognized us with its Emergency Assistance Award for the outstanding assistance we provided other utilities recovering last year from hurricanes Katrina, Rita and Wilma.

Our financial results mirror our operational success. With operating revenues of $6.6 billion, Georgia Power's 2005 earnings totaled $715 million, a $57 million, or 8.7 percent, increase from 2004. We earned a 14.15 percent total company return on average common equity during 2005. Georgia Power had net plant in service of $12.0 billion at the end of 2005, with total assets of $17.0 billion.

In 2005, we announced plans to merge one of our sister companies into Georgia Power; we made significant progress on the environmental front; and we overhauled our organizational structure to bring us even closer to our customers.

Late last year, the boards of directors of Southern Company, Savannah Electric and Georgia Power approved a plan to merge Savannah Electric into Georgia Power. This move should result in operational efficiencies and cost savings for Georgia Power.

Savannah Electric customers also are expected to benefit from Georgia Power's more diverse and cost-efficient generating fleet. We anticipate completing the merger by July 2006.

We continued our efforts last year to reduce the environmental impact of our operations by:

- Turning on selective catalytic reduction systems at plants Bowen, Hammond and Wansley. This is expected to reduce the company's emissions of nitrogen oxides and, therefore, its contribution to metro Atlanta's ozone from 15 percent to 6 percent.

- Filing applications for four more scrubbers – two for Plant Wansley and two additional scrubbers for Plant Bowen. Two scrubbers are already under construction at Plant Bowen. Not only will the scrubbers, which remove sulfur dioxide (SO_2) from power plant emissions, reduce SO_2 emissions on each of these generating units by as much as 95 percent, but they also will reduce emissions of fine particulates and mercury. This is important because the Environmental Protection Agency issued its first mercury rule last year requiring significant reductions in mercury emissions from power plants.

- Working closely with DeKalb County in metro Atlanta, which approved the development of a landfill gas generation plant and a 10-year contract to sell the energy to Georgia Power for our voluntary Green Energy program.

In the past 10 years, we have invested $1 billion in environmental controls, and we'll continue to invest in environmental improvement technologies. In fact, over the next five years, Georgia Power's additional environmental investment is expected to total at least $2.4 billion.

In 2005, we also implemented a new organizational structure that moves key company leaders closer to our customers, employees and the communities we serve. We now have officer positions in major cities around the state, including Athens, Augusta, Columbus, Macon, Rome, Valdosta and, following the merger, Savannah.

Our new structure allows us to enhance efficiencies and operate consistently around the state while providing multiple cross-company leadership development opportunities within Southern Company – a key priority as we work to further develop the diversity and strength of our management ranks.

We believe improving diversity in every facet of our business is, simply put, good for business. That's why last year, for example, we launched a Hispanic Resources Web site, a one-stop shop for information to assist Spanish-speaking customers.

After all our hard work, it's nice to be recognized for our success. *Profiles in Diversity Journal* named Georgia Power to its top-10 list of diversity innovation award winners. We also were one of the Fortune 500 companies recognized as the nation's "Best Workplaces for Commuters," in large part because of SmartRide, our company commuter program that has become more popular than ever because of rising fuel prices. *Site Selection* magazine also recognized us as one of the best company's in North America for economic development.

We're especially proud of our linemen, who really shined at the International Lineman's Rodeo last year in Kansas City, winning first place in the overall, overall apprentice, investor-owned utility and senior divisions, along with a handful of individual event awards.

Continued economic vitality in Georgia helped boost electricity sales and was a key contributor to our strong financial results last year. Businesses and individuals were drawn to the state, increasing the number of customers Georgia Power serves to 2.1 million in 2005, a 1.8 percent increase from the previous year. Our retail sales of electricity climbed 1.4 percent in 2005.

It's clear to me that the work our employees do day in and day out and their commitment to the company are what make us successful – they are our greatest asset.

The changes we made and initiatives we launched last year will help ensure that we continue doing what's best for our employees, customers and communities – that we live up to our motto of being a "Citizen Wherever We Serve" – as we work to meet the state's growing demand for energy.

Sincerely,

Michael D. Garrett
April 17, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Georgia Power Company:

We have audited the accompanying balance sheets and statements of capitalization of Georgia Power Company (the "Company") (a wholly owned subsidiary of Southern Company) as of December 31, 2005 and 2004, 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, 2005. 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 the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements (pages 25 to 57) present fairly, in all material respects, the financial position of Georgia Power Company at December 31, 2005 and 2004, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
February 27, 2006

OVERVIEW

Business Activities

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

Many factors affect the opportunities, challenges, and risks of the Company's primary business of selling electricity. These factors include the ability to maintain a stable regulatory environment, to achieve energy sales growth while containing costs, and to recover rising costs. These costs include those related to growing demand, increasingly stringent environmental standards, and fuel prices. In December 2004, the Company completed a major retail rate proceeding that is expected to provide earnings stability (2004 Retail Rate Plan). This regulatory action also enables the recovery of substantial capital investments to facilitate the continued reliability of the transmission and distribution network and continued environmental improvements at the generating plants. Appropriately balancing environmental expenditures with customer prices will continue to challenge the Company for the foreseeable future. The Company expects further rate proceedings in 2006 to address fuel cost recovery due to higher than expected fuel costs for coal and natural gas.

On December 13, 2005, the Company and Savannah Electric and Power Company (Savannah Electric) entered into a merger agreement, under which Savannah Electric will merge into the Company, with the Company continuing as the surviving corporation (the Merger). The Merger must be approved by Savannah Electric's preferred shareholders and is subject to receipt of certain regulatory approvals from the Federal Energy Regulatory Commission (FERC), the Georgia Public Service Commission (PSC), and the Federal Communications Commission. Pending regulatory approvals, the Merger is expected to be completed by July 2006. See FUTURE EARNINGS POTENTIAL – "Merger" and Note 3 to the financial statements under "Retail Regulatory Matters – Merger" for additional information.

Key Performance Indicators

In striving to maximize shareholder value while providing low-cost energy to more than two million customers, the Company continues to focus on several key indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income. The Company's financial success is directly tied to the satisfaction of its customers. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance, expected weather conditions, and expected capital expenditures. Net income is the primary component of the Company's contribution to Southern Company's earnings per share goal.

The Company's 2005 results compared to its targets for some of these indicators are reflected in the following chart.

Key Performance Indicator	2005 Target Performance	**2005 Actual Performance**
Customer Satisfaction	Top quartile in customer surveys	**Top quartile**
Peak Season EFOR	2.75% or less	**1.42%**
Net Income	$678 million	**$715 million**

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The strong financial performance achieved in 2005 reflects the focus that management places on these indicators, as well as the commitment shown by the employees in achieving or exceeding management's expectations.

Earnings

The Company's 2005 earnings totaled $715 million representing a $57 million (8.7 percent) increase over 2004. Operating income increased in 2005 due to higher base retail revenues resulting from the retail rate increase

effective January 1, 2005 and more favorable weather, as well as higher wholesale revenues resulting from new contracts effective January 1, 2005, partially offset by increased non-fuel operating expenses. The Company's 2004 earnings totaled $658 million representing a $27 million (4.3 percent) increase over 2003. Operating income increased in 2004 due to higher base retail revenues attributable to more favorable weather and customer growth during the year, partially offset by higher non-fuel operating expenses. In addition, lower depreciation and amortization expense resulting from a Georgia PSC three-year retail rate plan approved in 2001 (2001 Retail Rate Plan) significantly offset increased purchased power capacity expenses. The Company's 2003 earnings totaled $631 million, representing a $13 million (2.1 percent) increase over 2002 despite lower base retail revenues resulting from the extremely mild summer weather. Higher wholesale revenues and lower non-fuel operating expenses contributed to the 2003 increase.

RESULTS OF OPERATIONS

A condensed income statement for the Company is as follows:

	Amount	Increase (Decrease) From Prior Year		
	2005	**2005**	2004	2003
		(in millions)		
Operating revenues	**$6,634**	**$1,263**	$457	$ 92
Fuel	**1,831**	**598**	128	101
Purchased power	**1,170**	**194**	200	92
Other operation and maintenance	**1,481**	**81**	153	(78)
Depreciation and amortization	**504**	**229**	(74)	(54)
Taxes other than income taxes	**260**	**32**	15	11
Total operating expenses	**5,246**	**1,134**	422	72
Operating income	**1,388**	**129**	35	20
Total other income and (expense)	**(241)**	**(20)**	5	2
Income taxes	**431**	**52**	13	9
Net income	**716**	**57**	27	13
Dividends on preferred stock	**1**	**-**	-	-
Net income after dividends on preferred stock	**$ 715**	**$ 57**	$ 27	$ 13

Revenues

Operating revenues in 2005, 2004, and 2003 and the percent of change from the prior year are as follows:

	Amount		
	2005	2004	2003
		(in millions)	
Retail – prior year	**$4,777**	$4,310	$4,288
Change in -			
Base rates	**195**	-	-
Sales growth	**135**	151	30
Weather	**21**	32	(66)
Fuel cost recovery and other	**515**	284	58
Retail – current year	**$5,643**	4,777	4,310
Sales for resale -			
Non-affiliates	**519**	247	260
Affiliates	**265**	166	175
Total sales for resale	**784**	413	435
Other operating revenues	**207**	181	169
Total operating revenues	**$6,634**	$5,371	$4,914
Percent change	**23.5%**	9.3%	1.9%

Retail base revenues of $3.6 billion in 2005 increased by $351 million (10.9 percent) from 2004 primarily due to the retail rate increase effective January 1, 2005, sustained economic strength, customer growth, more favorable weather, and generally higher prices to large business customers. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information. Retail base revenues of $3.2 billion in 2004 increased by $183 million (6.0 percent) from 2003 primarily due to an improved economy, customer growth, generally higher prices to the Company's large business customers, and more favorable weather. Retail base revenues of $3 billion in 2003 decreased by $36 million (1.2 percent) from 2002 primarily due to extremely mild summer temperatures and the sluggish economy.

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. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information.

Wholesale revenues from sales to non-affiliated utilities were:

	2005	2004	2003
		(in millions)	
Unit power sales --			
Capacity	**$ 33**	$ 31	$ 34
Energy	**31**	33	31
Other power sales --			
Capacity and other	**155**	75	93
Energy	**300**	108	102
Total	**$519**	$247	$260

Revenues from unit power sales contracts remained relatively constant in 2005 and 2004. Revenues from unit power sales contracts decreased slightly in 2003 due to decreased energy sales. Revenues from other non-affiliated sales increased $272 million (148.6 percent) in 2005 and decreased $12 million (6.2 percent) and $8 million (3.9 percent) in 2004 and 2003, respectively. The increase in 2005 is due to new contracts with thirty electric membership corporation customers that went into effect in January 2005 which increased the demand for energy. The capacity component of these transactions increased $73.2 million in 2005 over 2004.

Revenues from sales to affiliated companies within the Southern Company electric system, as well as purchases of energy, will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliated sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the FERC. In 2005, kilowatt-hour (KWH) energy sales to affiliates increased 1.5 percent due to higher demand, while the increase in associated revenues was 59.4 percent due to higher fuel prices. In 2004, KWH energy sales to affiliates decreased 18.2 percent due to lower demand. However, the decline in associated revenues was only 4.9 percent due to higher fuel prices. In 2003, KWH energy sales to affiliates increased 47.5 percent due to the combination of increased demand by Southern Power to meet contractual obligations and the availability of power due to milder-than-normal weather in the Company's service territory. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost.

Other operating revenues increased $25.7 million (14.2 percent) in 2005 from 2004 primarily due to higher transmission revenues of $16 million related to work performed for the other owners of the integrated transmission system in the State of Georgia and higher revenues under the open access tariff agreement, higher outdoor lighting revenues of $5.4 million, and higher customer fees that went into effect in January 2005 of $5.9 million. Other operating revenues increased $11.7 million (6.9 percent) in 2004 over 2003 primarily due to higher revenues from outdoor lighting of $4.2 million and pole attachment rentals of $4.9 million and higher gains on sales of emission allowances of $2 million. Other operating revenues increased $4 million (2.4 percent) in 2003 from the prior year primarily due to an increase in the open access transmission tariff rate, which increased revenues $7 million, and higher revenues from increased customer demand for outdoor lighting services of $4 million, partially offset by lower revenues from the rental of electric property of $4 million.

Energy Sales

KWH sales for 2005 and the percent change by year were as follows:

	KWH	Percent Change		
	2005	**2005**	2004	2003
	(in billions)			
Residential	**23.6**	**2.9%**	5.3%	(1.7)%
Commercial	**29.8**	**6.3**	4.0	(0.1)
Industrial	**25.0**	**(5.0)**	2.5	(0.1)
Other	**0.6**	**(0.1)**	1.1	0.4
Total retail	**79.0**	**1.4**	3.8	(0.5)
Sales for resale -				
Non-affiliates	**11.2**	**88.2**	(32.5)	9.5
Affiliates	**4.9**	**1.5**	(18.2)	47.5
Total sales for resale	**16.1**	**49.6**	(26.8)	22.0
Total sales	**95.1**	**7.2**	(1.2)	2.6

Residential KWH sales increased 2.9 percent in 2005 over 2004 due to more favorable weather, customer growth of 1.7 percent, and a 1.1 percent increase in the average energy consumption per customer. Commercial KWH sales increased 6.3 percent due to more favorable weather, sustained economic strength, customer growth of 1.8 percent, and a reclassification of customers from industrial to commercial to be consistent with the rate structure approved by the Georgia PSC when compared

to 2004. Industrial sales decreased 5.0 percent primarily due to this reclassification of customers.

Residential KWH sales increased 5.3 percent in 2004 from 2003 due to more favorable weather and a 1.9 percent increase in residential customers. Commercial KWH sales increased 4.0 percent in 2004 due to an improved economy and a 2.8 percent increase in commercial customers. Industrial sales increased 2.5 percent in 2004 due to the improved economy.

Residential KWH sales decreased 1.7 percent in 2003 from 2002 due to the effect of the milder summer weather, despite the 2.0 percent increase in residential customers. Commercial KWH sales in 2003 declined slightly due to the milder summer weather, while industrial KWH sales declined slightly due to the sluggish economy. Average retail sales growth assuming normal weather is expected to be 2.1 percent from 2006 to 2010.

Fuel and Purchased Power 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 generating units. The amount and sources of generation, the average cost of fuel per net KWH generated, and the average cost of purchased power per net KWH were as follows:

	2005	2004	2003
Total generation (billions of KWH)	**80.5**	71.5	73.1
Sources of generation (percent) --			
Coal	**75.3**	75.4	75.4
Nuclear	**18.6**	22.5	21.6
Hydro	**2.4**	2.0	2.7
Oil and gas	**3.7**	0.1	0.3
Average cost of fuel per net KWH generated (cents) --	**2.04**	1.55	1.46
Average cost of purchased power per net KWH (cents) --	**7.25**	5.17	4.03

Fuel expense increased 48.5 percent in 2005 from the prior year primarily due to an increase in the average cost of fuel, particularly natural gas, and a 12.3 percent increase in generation to meet higher demand. Fuel expense increased 11.6 percent in 2004 over 2003 primarily due to an increase in the average cost of coal and natural gas. Fuel expense increased 10.1 percent in 2003 over 2002 due to an increase in generation of 3.9 percent because of higher wholesale energy demands and a 2.8 percent higher average cost of fuel due to the higher prices of coal and natural gas in 2003.

Purchased power expense increased $194 million (19.9 percent) in 2005, $200 million (25.9 percent) in 2004, and $92 million (13.3 percent) in 2003. These increases are primarily the result of new purchased power agreements (PPAs) between the Company and Southern Power that went into effect in each of 2004, 2003, and 2002. Additional capacity expenses associated with these PPAs were $30 million, $65 million, and $75 million in 2005, 2004, and 2003, respectively. The increases in purchased power expenses also reflect the impact of the significant increases in fuel costs discussed previously.

A significant upward trend in the cost of coal and natural gas has emerged since 2003, and volatility in these markets is expected to continue. Increased coal prices have been influenced by a worldwide increase in demand as a result of rapid economic growth in China as well as by increases in mining costs. Higher natural gas prices in the United States are the result of increased demand and slightly lower gas supplies despite increased drilling activity. Natural gas supply interruptions, such as those caused by the 2005 and 2004 hurricanes, result in an immediate market response; however, the long-term impact of this price volatility may be reduced by imports of natural gas and liquefied natural gas. Fuel expenses generally do not affect net income, since they are offset by fuel revenues under the Company's fuel cost recovery provisions.

Other Operating Expenses

In 2005, other operations and maintenance expenses increased $81 million (5.8 percent). Maintenance for generating plant and transmission and distribution increased $23.5 million and $13.9 million, respectively, as a result of scheduled outages and, to a lesser extent, certain flexible projects planned for other periods. Increased employee benefit expense of $18.4 million related to pension and medical benefits and higher property insurance costs of $5.3 million resulting from storm damage also contributed to the increase. Customer

assistance expense and uncollectible account expense also increased an additional $9.3 million in 2005 over 2004, primarily as a result of promotional expenses related to an energy efficiency program and an increased number of customer bankruptcies, respectively. In 2004, other operations and maintenance expenses increased $153 million (12.3 percent) due to the timing of generating plant maintenance of $39 million and transmission and distribution maintenance of $39 million. Increased employee benefit expense of $30 million related to pension and medical benefits and higher workers compensation expense of $8 million also contributed to the increase. In 2003, other operations and maintenance expenses decreased $78 million (5.9 percent) due to the timing of generating plant maintenance of $46 million and transmission and distribution maintenance of $8 million and lower severance costs of $8 million.

Depreciation and amortization increased $229 million (83 percent) in 2005 over 2004 primarily due to the expiration at the end of 2004 of certain provisions of the Company's 2001 Retail Rate Plan. In accordance with the 2001 Retail Rate Plan, the Company amortized an accelerated cost recovery liability as a credit to amortization expense and recognized new Georgia PSC-certified purchased power costs in rates evenly over the three years ended December 31, 2004. This treatment resulted in a credit to amortization expense of $187.1 million in 2004 and a total decrease in depreciation and amortization of $74 million and $54 million in 2004 and 2003, respectively. See Note 3 to the financial statements under "Retail Regulatory Matters -- Rate Plans" for additional information.

Taxes other than income taxes increased $32 million (14.1 percent) primarily due to higher municipal gross receipts taxes of $18.1 million resulting from increased operating revenues and higher property taxes of $14.0 million. Taxes other than income taxes increased $15 million (7.0 percent) in 2004 due to higher municipal gross receipts taxes associated with increased operating revenues. Taxes other than income taxes increased $11 million (5.4 percent) in 2003 due mainly to a favorable true-up of state property tax valuations in 2002.

Other Income and (Expense)

Allowance for equity funds used during construction remained relatively constant in 2005 and increased $15.9 million in 2004, primarily due to the construction of the McIntosh combined cycle Units 10 and 11 which were placed in service in June 2005.

Interest income remained relatively constant in 2005. Interest income decreased $9 million in 2004 and increased $12 million in 2003 when compared to the prior year primarily due to interest on a favorable income tax settlement of $14.5 million in 2003.

Interest expense increased $38.8 million (21.3 percent) in 2005 from 2004 primarily due to the issuance of additional senior notes in 2005 and generally higher interest rates on variable rate debt and commercial paper. Interest expense remained relatively constant in 2004. Interest expense increased in 2003 primarily due to an increase in senior notes outstanding that was partially offset by a reduction in short-term debt outstanding. The Company refinanced or retired $635 million, $400 million, and $665 million of securities in 2005, 2004, and 2003, respectively. Interest capitalized increased in 2005 and 2004 due to the Plant McIntosh construction referenced above and decreased in 2003 due to the transfer of a project to Southern Power in 2002.

Other income and (expense), net increased $17.1 million in 2005 from 2004 primarily due to $14.2 million of additional gas hedge gains. Other income and (expense), net decreased in 2004 primarily due to the $13 million disallowance of Plant McIntosh construction costs in December 2004, partially offset by a $7.5 million decrease in donations and $3.4 million in increased income from a customer pricing program. See Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Hedging Program" and "Plant McIntosh Construction Project" for additional information.

Effects of Inflation

The Company is subject to rate regulation that is based on the recovery of historical costs. In addition, the income tax laws are based on historical costs. Therefore, inflation creates an economic loss because the Company is recovering its costs of investments in dollars that have less purchasing power. While the inflation rate has been relatively low in recent years, it continues to have an adverse effect on the Company because of the large investment in utility plant with long economic lives. Conventional accounting for historical cost does not recognize this economic loss nor the partially offsetting gain that arises through financing facilities with fixed-

money obligations such as long-term debt, preferred stock, and preferred securities. Any recognition of inflation by regulatory authorities is reflected in the rate of return allowed in the Company's approved electric rates.

FUTURE EARNINGS POTENTIAL

General

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

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability of the Company to maintain a stable regulatory environment that continues to allow for the recovery of all prudently incurred costs. Future earnings in the near term will depend, in part, upon growth in energy sales, which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth in the Company's service area.

Environmental Matters

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S District Court for the Northern District of Georgia against the Company and Alabama Power, alleging that the Company and Alabama Power had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws with respect to certain coal-fired generating facilities. Through subsequent amendments and other legal proceedings, the EPA added Savannah Electric as a defendant to the original action and filed a separate action against Alabama Power after it was dismissed from the original action. In these lawsuits, the EPA alleges that NSR violations occurred at eight coal-fired generating facilities, including the Company's Plants Bowen and Scherer. The civil action requests penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. On June 3, 2005, the U.S. District for the Northern District of Alabama issued a decision in favor of Alabama Power on two primary legal issues in the case; however, the decision does not resolve the case, nor does it address other legal issues associated with the EPA's allegations. In accordance with a separate court order, Alabama Power and the EPA are currently participating in mediation with respect to the EPA's claims. The action against the Company and Savannah Electric has been administratively closed since the spring of 2001, and none of the parties has sought to reopen the case. See Note 3 to the financial statements under "Environmental Matters - New Source Review Actions."

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $32,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in this matter could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

In December 2002 and October 2003, the EPA issued final revisions to its NSR regulations under the Clean Air Act. A coalition of states and environmental organizations filed petitions for review of these regulations. On June 24, 2005, the U.S. Court of Appeals for the District of Columbia Circuit upheld, in part, the EPA's December 2002 revisions to its NSR regulations, which included changes to the regulatory exclusions and

methods of calculating emissions increases. However, the court vacated portions of those revisions, including those addressing the exclusion of certain pollution control projects. The October 2003 revisions, which clarified the scope of the existing Routine Maintenance, Repair and Replacement exclusion, have been stayed by the Court of Appeals pending its review of the rules. On October 20, 2005, the EPA also published a proposed rule clarifying the test for determining when an emissions increase subject to the NSR requirements has occurred. The impact of these revisions and proposed rules will depend on adoption of the final rules by the EPA and the State of Georgia's implementation of such rules, as well as the outcome of any additional legal challenges, and, therefore, cannot be determined at this time.

Carbon Dioxide Litigation

In July 2004, attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed a complaint in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. A nearly identical complaint was filed by three environmental groups in the same court. The complaints allege that the companies' emissions of carbon dioxide, a greenhouse gas, contribute to global warming, which the plaintiffs assert is a public nuisance. Under common law public and private nuisance theories, the plaintiffs seek a judicial order (1) holding each defendant jointly and severally liable for creating, contributing to, and/or maintaining global warming and (2) requiring each of the defendants to cap its emissions of carbon dioxide and then reduce those emissions by a specified percentage each year for at least a decade. Plaintiffs have not, however, requested that damages be awarded in connection with their claims. Southern Company believes these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2005, the U.S. District Court for the Southern District of New York granted Southern Company's and the other defendants' motions to dismiss these cases. The plaintiffs filed an appeal to the U.S. Court of Appeals for the Second Circuit on October 19, 2005. The ultimate outcome of these matters cannot be determined at this time.

Plant Wansley Environmental Litigation

In December 2002, the Sierra Club, Physicians for Social Responsibility, Georgia Forestwatch, and one individual filed a civil suit in the U.S. District Court for the Northern District of Georgia against the Company for alleged violations of the Clean Air Act at four of the units at Plant Wansley. 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. The liability phase of the case has concluded with the court ruling in favor of the Company in part and the plaintiffs in part. In March 2005, the U.S. Court of Appeals for the Eleventh Circuit accepted the Company's petition for review of the district court's order, and oral arguments were held on January 24, 2006. The district court case has been administratively closed pending that appeal. If necessary, the district court will hold a separate trial which will address civil penalties and possible injunctive relief requested by the plaintiffs. The ultimate outcome of this matter cannot currently be determined; however, an adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require the payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

Environmental Statutes and Regulations

General

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. Applicable statutes 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 these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2005, the Company had invested approximately $1.2 billion in

capital projects to comply with these requirements, with annual costs of $117.4 million, $47.4 million, and $105.7 million for 2005, 2004, and 2003, respectively. Over the next decade, the Company expects that capital expenditures could exceed an additional $3.3 billion to assure compliance with existing and new regulations, including $410 million, $674.6 million, and $515.8 million for 2006, 2007, and 2008, respectively. Because the Company's compliance strategy is impacted by changes to existing environmental laws and regulations, the cost, availability, and existing inventory of emission allowances, and the Company's fuel mix, the ultimate outcome cannot be determined at this time. Environmental costs that are known and estimable at this time are included in capital expenditures discussed under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein.

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

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Through 2005, the Company had spent approximately $787.9 million in reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions and in monitoring emissions pursuant to the Clean Air Act. Additional controls have been announced and are currently being installed at several plants to further reduce SO_2 and NO_x emissions, maintain compliance with existing regulations, and to meet new requirements.

Approximately $699.8 million of these expenditures are related to reducing NO_x emissions pursuant to state and federal requirements in connection with the EPA's one-hour ozone standard and the 1998 regional NO_x reduction rules. Although the State of Georgia was originally included in the states subject to the regional NO_x rules, the EPA, in August 2005, stayed compliance with these requirements and initiated rulemakings to address issues raised in a petition for reconsideration filed by a coalition of Georgia industries. The impact of the 1998 regional NO_x reduction rules for Georgia will depend on the outcome of the petition for reconsideration and/or any subsequent development and approval of the State of Georgia's state implementation plan.

In 2005, the EPA revoked the one-hour ozone standard and published the final set of rules for implementation of the new, more stringent eight-hour ozone standard. Areas within the Company's service area that have been designated as nonattainment under the eight-hour ozone standard include Macon (Georgia) and a 20-county area within metropolitan Atlanta. State implementation plans, including new emission control regulations necessary to bring those areas into attainment are required for most areas by June 2007. These state implementation plans could require further reductions in NO_x emissions from power plants.

During 2005, the EPA's fine particulate matter "nonattainment" designations became effective for several areas within the Company's service area in Georgia, and the EPA proposed a rule for the implementation of the fine particulate matter standard. The EPA plans to finalize the proposed implementation rule in 2006. State plans for addressing the nonattainment designations are required by April 2008 and could require further reductions in SO_2 and NO_x emissions from power plants. The EPA has also published proposed revisions to lower the level of particulate matter currently allowed.

The EPA issued the final Clean Air Interstate Rule on March 10, 2005. This cap-and-trade rule addresses power plant SO_2 and NO_x emissions that were found to contribute to nonattainment of the eight-hour ozone and fine particulate matter standards in downwind states. Twenty-eight eastern states, including the State of Georgia, are subject to the requirements of the rule. The rule calls for additional reductions of NO_x and/or SO_2 to be achieved in two phases, 2009/2010 and 2015. These reductions will be accomplished by the installation of additional emission controls at the Company's coal-fired facilities or by the purchase of emission allowances from a cap-and-trade program.

The Clean Air Visibility Rule (formerly called the Regional Haze Rule) was finalized on July 6, 2005. The goal of this rule is to restore natural visibility conditions in certain areas (primarily national parks

and wilderness areas) by 2064. The rule involves the application of Best Available Retrofit Technology (BART) requirements and a review each decade, beginning in 2018, of progress toward the goal. BART requires that sources that contribute to visibility impairment implement additional emission reductions, if necessary, to make progress toward remedying current visibility concerns. For power plants, the Clean Air Visibility Rule allows states to determine that the Clean Air Interstate Rule satisfies BART requirements for SO_2 and NO_x. However, additional requirements could be imposed. By December 17, 2007, states must submit implementation plans that contain emission reduction strategies for implementing BART requirements and for achieving sufficient and reasonable progress toward the goal.

On March 15, 2005, the EPA announced the final Clean Air Mercury Rule, a cap-and-trade program for the reduction of mercury emissions from coal-fired power plants. The rule sets caps on mercury emissions to be implemented in two phases, 2010 and 2018, and provides for an emission allowance trading market. The Company anticipates that emission controls installed to achieve compliance with the Clean Air Interstate Rule and the eight-hour ozone and fine-particulate standards will also result in mercury emission reductions. However, the long-term capability of emission control equipment to reduce mercury emissions is still being evaluated, and the installation of additional control technologies may be required.

The impacts of the eight-hour ozone standard, the fine particulate matter nonattainment designations, the Clean Air Interstate Rule, the Clean Air Visibility Rule, and the Clear Air Mercury Rule on the Company, will depend on the development and implementation of rules at the state level. States implementing the Clean Air Mercury Rule and the Clear Air Interstate Rule, in particular, have the option not to participate in the national cap-and-trade programs and could require reductions greater than those mandated by the federal rules. Such impacts will also depend on resolution of pending legal challenges to the Clean Air Interstate Rule, the Clean Air Mercury Rule and a related petition from the State of North Carolina under section 126 of the Clean Air Act, also related to the interstate transport of air pollutants. Therefore, the full impacts of these regulations on the Company cannot be determined at this time. The Company has developed and continually updates a comprehensive environmental compliance strategy to comply with the continuing and new environmental requirements discussed above. As part of this strategy, the Company plans to install additional SO_2, NO_x, and mercury emission controls within the next several years to assure continued compliance with applicable air quality requirements.

Water Quality

In July 2004, the EPA published final rules under the Clean Water Act for the purpose of reducing impingement and entrainment of fish and fish larvae at power plants' cooling water intake structures. The new rules require baseline biological information and, perhaps, installation of fish protection technology near some intake structures at existing power plants.

The Company is installing cooling towers at additional facilities under the Clean Water Act to cool water prior to discharge. Near Atlanta, a cooling tower for one plant was completed in 2004 and two others are scheduled for completion in 2008. The total estimated cost of these projects is $173 million, with $85 million remaining to be spent. The Company is also conducting a study of the aquatic environment at another facility to determine if further thermal controls are necessary at that plant.

The full impact of these new rules will depend on the results of studies and analyses performed as part of the rules' implementation and the actual requirements established by the State of Georgia, and therefore, cannot be determined at this time

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and release 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 and monitor known sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Remediation" for additional information.

Under Georgia PSC ratemaking provisions, $22 million has been deferred in a regulatory liability account related to certain environmental insurance settlements. Under the 2004 Retail Rate Plan, this regulatory liability is being amortized as a credit to expense over a three-year period that began January 1, 2005. However, the Georgia PSC also approved an annual environmental accrual of $5.4 million. Environmental remediation expenditures are being charged against the resulting reserve as they are incurred. The annual accrual amount will be reviewed and adjusted in future regulatory proceedings.

Global Climate Issues

Domestic efforts to limit greenhouse gas emissions have been spurred by international discussions surrounding the Framework Convention on Climate Change, and specifically the Kyoto Protocol -- which proposes constraints on the emissions of greenhouse gases for a group of industrialized countries. The Bush Administration has not supported U.S. ratification of the Kyoto Protocol or other mandatory carbon dioxide reduction legislation; however, in 2002, it did announce a goal to reduce the greenhouse gas intensity of the U.S. – the ratio of greenhouse gas emissions to the value of U.S. economic output -- by 18 percent by 2012. A year later, the Department of Energy (DOE) announced the Climate VISION program to support this goal. Energy-intensive industries, including electricity generation, are the initial focus of this program. Southern Company is involved in the development of a voluntary electric utility sector climate change initiative in partnership with the government. In a memorandum of understanding signed in December 2004 with the DOE under Climate VISION, the utility sector pledged to reduce its greenhouse gas emissions rate by 3 percent to 5 percent by 2010-2012. The Company is continuing to evaluate future energy and emissions profiles relative to the Climate VISION program and is analyzing voluntary programs to support the industry initiative.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates at market-based prices. The Company also has FERC authority to make short-term opportunity sales at market rates. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in that proceeding. In February 2005, Southern Company submitted responsive information. In February 2006, the FERC suspended the proceeding. Any new market-based rate transactions in its retail service territory entered into after February 27, 2005 are subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. The impact of such sales through December 31, 2005 is not expected to exceed $4.9 million. The refund period covers 15 months. In the event that the FERC's default mitigation measures for entities that are found to have market power are ultimately applied, the Company may be required to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates. The final outcome of this matter will depend on the form in which the final methodology for assessing generation market power and mitigation rules may be ultimately adopted and cannot be determined at this time.

In addition, in May 2005, the FERC started an investigation to determine whether Southern Company satisfies the other three parts of the FERC's market-based rate analysis: transmission market power, barriers to entry, and affiliate abuse or reciprocal dealing. The FERC established a new refund period related to this expanded investigation. Any and all new market-based rate transactions both inside and outside Southern Company's retail service territory involving any Southern Company subsidiary, including the Company, will be subject to refund to the extent the FERC orders lower rates as a result of this new investigation, with the 15-month refund period beginning July 19, 2005. The impact of such sales through December 31, 2005 is not expected to exceed $10.9 million, of which $3.2 million relates to sales inside the retail service territory as discussed above. The FERC also directed that this expanded proceeding be held in abeyance pending the outcome of the proceeding on the IIC discussed below.

The Company believes that there is no meritorious basis for this proceeding and is vigorously defending itself in this matter. However, the final outcome of this

matter, including any remedies to be applied in the event of an adverse ruling in this proceeding, cannot now be determined.

Intercompany Interchange Contract

The Company's generation fleet in its retail service territory is operated under the IIC, as approved by the FERC. In May 2005, the FERC also initiated a new proceeding to examine (1) the provisions of the IIC among Alabama Power, the Company, Gulf Power, Mississippi Power, Savannah Electric, Southern Power, and Southern Company Services, Inc., as agent, under the terms of which the power pool of Southern Company is operated, and, in particular, the propriety of the continued inclusion of Southern Power as a party to the IIC, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining Southern Power as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of Southern Power, the FERC authorized Southern Power's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct. The FERC order directs that the administrative law judge who presided over the McIntosh PPA proceeding discussed herein under "PSC Matters – Plant McIntosh Construction Project", be assigned to preside over the hearing in this proceeding and that the testimony and exhibits presented in that proceeding be preserved to the extent appropriate. Hearings are scheduled for September 2006. Effective July 19, 2005, revenues from transactions under the IIC involving any Southern Company subsidiaries, including the Company, are subject to refund to the extent the FERC orders any changes to the IIC.

The Company believes that there is no meritorious basis for this proceeding and is vigorously defending itself in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in this proceeding, cannot now be determined.

Generation Interconnection Agreements

In July 2003, the FERC issued its final rule on the standardization of generation interconnection agreements and procedures (Order 2003). Order 2003 shifts much of the financial burden of new transmission investment from the generator to the transmission provider. The FERC has indicated that Order 2003, which was effective January 20, 2004, is to be applied prospectively to interconnection agreements. Subsidiaries of Tenaska, Inc., as counterparties to three previously executed interconnection agreements with subsidiaries of Southern Company, including the Company, have filed complaints at the FERC requesting that the FERC modify the agreements and that the Company refund a total of $7.9 million previously paid for interconnection facilities, with interest. The Company has opposed all such requests, and the proceedings are still pending. The impact of Order 2003 and its subsequent rehearings on the Company and the final results of these matters cannot be determined at this time.

Transmission

In December 1999, the FERC issued its final rule on Regional Transmission Organizations (RTOs). Since that time, there have been a number of additional proceedings at the FERC designed to encourage further voluntary formation of RTOs or to mandate their formation. However, at the current time, there are no active proceedings that would require the Company to participate in an RTO. Current FERC efforts that may potentially change the regulatory and/or operational structure of transmission include rules related to the standardization of generation interconnection, as well as an inquiry into, among other things, market power by vertically integrated utilities. See "Generation Interconnection Agreements" and "Market-Based Rate Authority" herein for additional information. The final outcome of these proceedings cannot now be determined. However, the Company's financial condition, results of operations, and cash flows could be adversely affected by future changes in the federal regulatory or operational structure of transmission.

PSC Matters

Merger

In connection with the Merger, the Company and Savannah Electric plan to establish a coastal regional organization for the Company that will be operating following completion of the Merger. Management expects that current Savannah Electric employees will fill most of the positions in the new regional organization.

While the Georgia PSC does not have specific approval authority over the merger of electric utilities, in January 2006, the Company and Savannah Electric filed an application with the Georgia PSC for certain approvals necessary to complete the Merger. In particular, the Company and Savannah Electric are seeking the approval of the Georgia PSC with respect to the following matters:

- the transfer of Savannah Electric's generating facilities and certification of the generating facilities as the Company's assets;
- amendments to the Company's Integrated Resource Plan to add the current Savannah Electric's customers and generating facilities;
- the transfer of Savannah Electric's assigned service territory to the Company;
- adoption of the Company's service rules and regulations to the current Savannah Electric customers;
- new fuel rate and base rate schedules that would apply to the Company's sale of electricity to the current Savannah Electric customers;
- adoption of a "merger transition adjustment" rate that would be used to more closely align Savannah Electric's existing base rates to those of the Company and a "merger transition credit" rate that would credit the additional revenues collected from former Savannah Electric customers to the Company's existing customers; and
- the issuance of additional shares of the Company's common stock to Southern Company in exchange for Southern Company's shares of Savannah Electric common stock.

The Company has also requested the Georgia PSC to better align the rates for Savannah Electric's customers with those of the Company. Currently, Savannah Electric customers pay slightly lower base rates and significantly higher fuel rates than the Company's customers. The overall effect is that Savannah Electric customers pay substantially higher overall costs for electricity. See "Fuel Cost Recovery" herein for additional information.

Rate Plans

In December 2004, the Georgia PSC approved the 2004 Retail Rate Plan for the three-year period ending December 31, 2007. Under the terms of the 2004 Retail Rate Plan, earnings are being evaluated annually against a retail return on common equity (ROE) range of 10.25 percent to 12.25 percent. Two-thirds of any earnings above 12.25 percent will be applied to rate refunds, with the remaining one-third retained by the Company. Retail rates were increased by approximately $194 million and customer fees were increased by approximately $9 million effective January 1, 2005 to cover the higher costs of purchased power; operation and maintenance expenses; environmental compliance; and continued investment in new generation, transmission and distribution facilities to support growth and ensure reliability. In 2005 the Company recorded $2.7 million revenue subject to refund for estimated earnings above 12.25 percent retail ROE.

The Company is required to file a general rate case by July 1, 2007, in response to which the Georgia PSC would be expected to determine whether the 2004 Retail Rate Plan should be continued, modified, or discontinued. Until then, the Company will not file for a general base rate increase unless its projected retail ROE falls below 10.25 percent. However, in connection with the Merger, the Company has requested Georgia PSC approval of a "merger transition adjustment" that would be used to adjust Savannah Electric's existing base rates to more closely match the existing base rates for the Company. See Note 3 to the financial statements under "Retail Regulatory Matters - Rate Plans" for additional information.

Plant McIntosh Construction Project

In December 2002 after a competitive bidding process, the Georgia PSC certified PPAs between Southern Power and the Company and Savannah Electric for capacity from Plant McIntosh Units 10 and 11, construction of which was completed in June 2005. In April 2003, Southern Power applied for FERC approval of these PPAs. In July 2003, the FERC accepted the PPAs to become effective June 1, 2005, subject to refund, and ordered that hearings be held. Intervenors opposed the FERC's acceptance of the PPAs, alleging that they did not meet the applicable standards for market-based rates between affiliates. To ensure the timely completion of the Plant McIntosh construction project and the availability of the units in the summer of 2005 for their retail customers, in May 2004, the Company and Savannah Electric requested the Georgia PSC to direct them to acquire the Plant McIntosh construction project. The Georgia PSC issued such an order and the transfer occurred on May 24, 2004 at a total cost of approximately $415 million, including

$14 million of transmission interconnection facilities. Subsequently, Southern Power filed a request to withdraw the PPAs and to terminate the ongoing FERC proceedings. In August 2004, the FERC issued a notice accepting the request to withdraw the PPAs and permitting such request to become effective by operation of law. However, the FERC made no determination on what additional steps may need to be taken with respect to testimony provided in the proceedings. See "FERC Matters - Intercompany Interchange Contract" above for additional information.

In connection with the 2004 Retail Rate Plan, the Georgia PSC approved the transfer of the Plant McIntosh construction project at a total fair market value of approximately $385 million. This value reflected an approximate $16 million disallowance, of which $13 million was attributable to the Company, and reduced the Company's 2004 net income by approximately $8 million. The Georgia PSC also certified a total completion cost of $547 million for the project. In June 2005, Plant McIntosh Units 10 and 11 were placed in service at a total cost that did not exceed the certified amount. Under the 2004 Retail Rate Plan, the Plant McIntosh revenue requirements impact will be reflected in the Company's rates evenly over the three years ending 2007. See Note 3 to the financial statements under "Retail Regulatory Matters -- Rate Plans" and "Plant McIntosh Construction Project" for additional information.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. In recent months, the Company has experienced higher than expected fuel costs for coal and natural gas. Those higher fuel costs have increased the under recovered fuel costs included in the balance sheets herein.

In May 2005, the Georgia PSC approved the Company's request to increase customer fuel rates by approximately 9.5 percent to recover under recovered fuel costs of approximately $508 million existing as of May 31, 2005 over a four-year period that began June 1, 2005. Under recovered fuel amounts for the period subsequent to June 1, 2005 totaled $327.5 million through December 31, 2005. The Georgia PSC's order instructed that such amounts be reviewed semi-annually beginning February 2006. If the amount under or over recovered exceeds $50 million at the evaluation date, the Company would be required to file for a temporary fuel rate change. In addition, Savannah Electric's under recovered fuel costs totaled $77.7 million at December 31, 2005. In accordance with the Georgia PSC order, Savannah Electric was scheduled to file an additional request for a fuel cost recovery increase in January 2006. The Company has agreed with a Georgia PSC staff recommendation to forego the temporary fuel rate process, and Savannah Electric has postponed its scheduled filing. Instead, the Company and Savannah Electric will file a combined request in March 2006 to increase the Company's fuel cost recovery rate.

The case will seek approval of a fuel cost recovery rate based upon future fuel cost projections for the combined Company and Savannah Electric generating fleet as well as the under recovered fuel balances existing at June 30, 2006. The new fuel cost recovery rate would be billed beginning in July 2006 to all of the Company's customers, including the existing Savannah Electric customers. Under recovered amounts as of the date of the Merger will be paid by the appropriate customer groups.

In August 2005, the Georgia PSC initiated an investigation of Savannah Electric's fuel practices. In February 2006, an investigation of the Company's fuel practices was initiated. The Company and Savannah Electric are responding to data requests and cooperating in the investigations. The final outcome of this matter cannot now be determined.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable cost and amounts billed in current regulated rates. Accordingly, any increase in the billing factor would have no significant effect on the Company's revenues or net income, but would increase annual cash flow.

Nuclear

As part of a potential expansion of Plant Vogtle, the Company and Southern Nuclear have notified the Nuclear Regulatory Commission (NRC) of their intent to apply for an early site permit (ESP) this year and a combined construction and operating license (COL) in 2008. In addition, a reactor design from Westinghouse Electric Company has been selected and a purchase agreement is being negotiated. Participation agreements have been reached with each of the existing Plant Vogtle co-owners. See Note 4 to the financial statements for additional information on

these co-owners. At this point, no final decision has been made regarding actual construction. The NRC's streamlined licensing process for new nuclear units allows utilities to seek regulatory approval at various stages. These stages include design certification, which is obtained by the reactor vendor, and the ESP and COL, which are each obtained by the owner-operators of the units. An ESP indicates site approval is obtained before a company decides to build and the COL provides regulatory approval for building and operating the plant. In addition, any generation by the Company must be certified by the Georgia PSC.

Southern Company also is participating in NuStart Energy Development, LLC (NuStart Energy), a broad-based nuclear industry consortium formed to share the cost of developing a COL and the related NRC review. NuStart Energy plans to complete detailed engineering design work and to prepare COL applications for two advanced reactor designs, then to choose one of the applications and file it for NRC review and approval. The COL ultimately is expected to be transferred to one or more of the consortium companies; however, at this time, none of them have committed to build a new nuclear plant.

Other Matters

In accordance with Financial Accounting Standards Board (FASB) Statement No. 87, Employers' Accounting for Pensions, the Company recorded non-cash pension income, before tax, of approximately $21 million, $35 million, and $54 million in 2005, 2004, and 2003, respectively. Postretirement benefit costs for the Company were $47 million, $44 million, and $41 million in 2005, 2004, and 2003, respectively. Both pension and postretirement costs are expected to trend upward. Such amounts are dependent on several factors including trust earnings and changes to the plans. A portion of pension income and postretirement benefit costs is capitalized based on construction-related labor charges. For the Company, pension income or expense and postretirement benefit costs are a component of the regulated rates and generally do not have a long-term effect on net income. For more information regarding pension and postretirement benefits, see Note 2 to the financial statements.

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

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

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

Electric Utility Regulation

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

As reflected in Note 1 to the financial statements under "Regulatory Assets and Liabilities," significant regulatory assets and liabilities have been recorded.

Management reviews the ultimate recoverability of these regulatory assets and liabilities based on applicable regulatory guidelines and accounting principles generally accepted in the United States. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

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

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

Unbilled Revenues

Revenues related to the sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated. Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, power delivery volume, and other operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.

New Accounting Standards

Income Taxes

In December 2004, the FASB issued FASB Staff Position 109-1, Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004 (FSP 109-1), which requires that the generation deduction be accounted for as a special tax deduction rather than as a tax rate reduction. The Company adopted FSP 109-1 in the first quarter of 2005 with no material impact on its financial statements.

Conditional Asset Retirement Obligations

Effective December 31, 2005, the Company adopted the provision of FASB Interpretation No. 47, Conditional Asset Retirement Obligations (FIN 47), which requires that an asset retirement obligation be recorded even though the timing and/or method of settlement are conditional on future events. Prior to December 2005, the Company did not recognize asset retirement obligations for asbestos removal because the timing of retirements was dependent on future events. For additional information, see Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal."

At December 31, 2005, the Company recorded additional asset retirement obligations (and assets) of approximately $91 million. The adoption of FIN 47 did not have any effect on the Company's income statement.

Stock Options

On January 1, 2006, the Company adopted FASB Statement No. 123R, Share-Based Payment, on a modified prospective basis. This statement requires that compensation cost relating to share-based payment transactions be recognized in financial statements. That cost will be measured based on the grant date fair value of the equity or liability instruments issued. Although the compensation expense required under the revised statement differs slightly, the impacts on the Company's financial statements are similar to the pro forma disclosures included in Note 1 to the financial statements under "Stock Options."

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition continued to be stable at December 31, 2005 with emphasis on cost control measures combined with significantly lower costs of capital, achieved through the refinancing and/or redemption of higher-cost securities. Cash flow from operations increased $56 million resulting primarily from increased retail operating revenues (see RESULTS OF OPERATIONS herein), partially offset by the increase in under recovered deferred fuel costs.

Fuel costs are generally recoverable in future periods and are reflected on the balance sheets as under recovered regulatory clause revenues. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information.

In 2005, gross utility plant additions were $906 million. These additions were primarily related to Plant McIntosh Units 10 and 11, transmission and distribution facilities, nuclear fuel, and equipment to comply with environmental standards. The majority of funds needed for gross property additions for the last several years have been provided from operating activities and capital contributions from Southern Company. The statements of cash flows provide additional details.

The Company's ratio of common equity to total capitalization -- including short-term debt -- was 48.3 percent in 2005, 47.7 percent in 2004, and 48.3 percent in 2003. The Company has received investment grade ratings from the major rating agencies.

Sources of Capital

The Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows. However, the type and timing of any future financings, if needed, will depend on market conditions, regulatory approval, and other factors.

The issuance of long-term securities by the Company is subject to the approval of the Georgia PSC. In addition, the issuance of short-term debt securities by the Company is subject to regulatory approval by the FERC following the repeal of the Public Utility Holding Company Act of 1935, as amended, on February 8, 2006. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the appropriate regulatory authorities, as well as the amounts registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company.

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

To meet short-term cash needs and contingencies, the Company had credit arrangements with banks totaling $780 million, of which $778 million was unused, at the beginning of 2006. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper and extendible commercial notes at the request and for the benefit of the Company and the other retail operating companies.

Proceeds from such issuances for the benefit of the Company are loaned directly to the Company and are not commingled with proceeds from issuances for the benefits of any other operating company. The obligations of each company under these arrangements are several; there is no cross affiliate credit support. As of December 31, 2005, the Company had outstanding $268 million of commercial paper and no extendible commercial notes.

At the beginning of 2006, bank credit arrangements were as follows:

		Expires		
Total	Unused	2006	2007	2010
		(in millions)		
$780	$778	$70	$350	$360

The credit arrangements that expire in 2006 allow for the execution of term loans for an additional two-year period.

Financing Activities

During 2005, the Company issued $810 million of long-term debt. The issuances were used to refund $635 million of long-term debt and to fund the Company's ongoing construction program.

Subsequent to December 31, 2005, the Company redeemed all of its outstanding preferred stock at a redemption price of $107 per share.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- or Baa3 or below. Generally, collateral may be provided for by a Southern Company guaranty, letter of credit, or cash. These contracts are primarily for physical electricity purchases and sales. At December 31, 2005, the maximum potential collateral requirements at a BBB- or Baa3 rating were approximately $6 million. The maximum potential collateral requirements at a rating below BBB- or Baa3 were approximately $245 million.

The Company is also party to certain derivative agreements that could require collateral and/or accelerated payment in the event of a credit rating change to below investment grade. These agreements are primarily for natural gas price risk management activities. At December 31, 2005, the Company had no material exposure related to these agreements.

Market Price Risk

Due to cost-based rate regulation, the Company has limited exposure to market rate 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 and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress tests, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company has entered into forward starting interest rate swaps that have been designated as hedges. These swaps have a notional amount of $300 million and are related to anticipated debt issuances over the next two years. The weighted average interest rate on outstanding variable long-term debt that has not been hedged at January 1, 2006 was 3.56 percent. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $3.3 million at January 1, 2006. For further information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

To mitigate residual risks relative to movements in electricity prices, the Company enters into fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, into similar contracts for gas purchases.

The Company has implemented a fuel hedging program at the instruction of the Georgia PSC. Fair

value of changes in energy-related derivative contracts and year-end valuations were as follows at December 31:

	Changes in Fair Value	
	2005	2004
	(in millions)	
Contracts beginning of year	**$5.8**	$ 3.2
Contracts realized or settled	**(40.0)**	(12.2)
Current period changes (a)	**60.8**	14.8
Contracts end of year	**$26.6**	$ 5.8

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

	Source of 2005 Year-End Valuation Prices		
	Total	Maturity	
	Fair Value	Year 1	1-3 Years
		(in millions)	
Actively quoted	**$26.8**	$16.4	$10.4
External sources	**(0.2)**	(0.2)	-
Contracts end of year	**$26.6**	$16.2	$10.4

Unrealized gains and losses from mark to market adjustments on derivative contracts related to the Company's fuel hedging programs are recorded as regulatory assets and liabilities. Realized gains and losses from these programs are included in fuel expense and are recovered through the Company's fuel cost recovery mechanism. Of the net gains, the Company is allowed to retain 25 percent in earnings. In 2005, the Company had a total net gain of $64.1 million, of which the Company retained $16.0 million. See Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Hedging Program" for additional information. Gains and losses on derivative contracts that are not designated as hedges are recognized in the statements of income as incurred. At December 31, 2005, the fair value of derivative energy contracts was reflected in the financial statements as follows:

	Amounts
	(in millions)
Regulatory liabilities, net	$26.7
Net income	(0.1)
Total fair value	$26.6

Unrealized gains (losses) recognized in income in 2005, 2004, and 2003 were not material. The Company is exposed to market price risk in the event of nonperformance by counterparties to the derivative energy contracts. The Company's policy is to enter into agreements with counterparties that have investment grade credit ratings by Moody's and Standard & Poor's or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to be $1.3 billion for 2006, $1.4 billion for 2007, and $1.3 billion for 2008. Environmental expenditures included in these amounts are $410 million, $674.6 million, and $515.8 million for 2006, 2007, and 2008, respectively. Actual construction costs may vary from this estimate because of changes in such factors as: business conditions; environmental regulations; nuclear plant regulations; FERC rules and transmission regulations; load projections; the cost and efficiency of construction labor, equipment, and materials; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

As a result of requirements by the NRC, the Company has established external trust funds for nuclear decommissioning costs. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning." Also as discussed in Note 1 to the financial statements under "Nuclear Fuel Disposal Costs," in 1993 the DOE implemented a special assessment over a 15-year period on utilities with nuclear plants to be used for the decontamination and decommissioning of its nuclear fuel enrichment facilities.

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the Georgia PSC and the FERC.

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

Amounts in the following chart exclude any effects on the Company of the Merger.

Contractual Obligations

	2006	2007-2008	2009-2010	After 2010	Total
			(in millions)		
Long-term debt [a] --					
Principal	$153	$306	$282	$4,563	$5,304
Interest	265	496	468	4,989	6,218
Preferred stock	15	-	-	-	15
Commodity derivative obligations[b]	12	-	-	-	12
Operating leases	34	58	44	58	194
Purchase commitments[c] --					
Capital [d]	1,251	2,738	2,421	-	6,410
Coal	1,579	2,220	694	40	4,533
Nuclear fuel	44	42	25	64	175
Natural gas[e]	577	525	511	2,047	3,660
Purchased power	343	689	559	994	2,585
Long-term service agreements	7	18	24	144	193
Trusts[f] --					
Nuclear decommissioning	7	14	14	117	152
Postretirement benefits	18	41	-	-	59
DOE assessments	4	-	-	-	4
Total	$4,309	$7,147	$5,042	$13,016	$29,514

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2006, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest risk.

(b) For additional information see Notes 1 and 6 to the financial statements herein.

(c) The Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses for the last three years were $1.5 billion, $1.4 billion, and $1.2 billion, respectively.

(d) The Company forecasts capital expenditures over a five-year period. Amounts represent current estimates of total expenditures, excluding those amounts related to contractual purchase commitments for uranium and nuclear fuel conversion, enrichment, and fabrication services. At December 31, 2005, significant purchase commitments were outstanding in connection with the construction program.

(e) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on the New York Mercantile Exchange future prices at December 31, 2005.

(f) Projections of nuclear decommissioning trust contributions are based on the 2004 Retail Rate Plan. The Company forecasts postretirement trust contributions over a three-year period. No contributions related to the Company's pension trust are currently expected during this period. See Note 2 to the financial statements for additional information related to the pension and postretirement plans, including estimated benefit payments. Certain benefit payments will be made through the related trusts. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2005 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales growth, storm cost recovery and repairs, environmental regulations and expenditures, the Company's projections for postretirement benefit trust contributions, financing activities, access to sources of capital, the proposed merger of Savannah Electric and the Company, the impacts of the adoption of new accounting rules, completion of construction projects, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will", "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory change, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, and implementation of the Energy Policy Act of 2005, and also changes in environmental, tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including FERC matters and the pending EPA civil action against the Company;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and population, and business growth (and declines);
- available sources and costs of fuels;
- ability to control costs;
- investment performance of the Company's employee benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate cases related to fuel cost recovery;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due;
- the ability to obtain new short- and long-term contracts with neighboring utilities;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents similar to the August 2003 power outage in the Northeast;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports, including the Form 10-K, filed by the Company from time to time with the Securities and Exchange Commission.

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

STATEMENTS OF INCOME

For the Years Ended December 31, 2005, 2004, and 2003

Georgia Power Company 2005 Annual Report

	2005	2004	2003
		(in thousands)	
Operating Revenues:			
Retail sales	**$5,642,812**	$4,776,985	$4,309,972
Sales for resale --			
Non-affiliates	**519,673**	246,545	259,376
Affiliates	**264,989**	166,245	174,855
Other revenues	**206,729**	181,033	169,304
Total operating revenues	**6,634,203**	5,370,808	4,913,507
Operating Expenses:			
Fuel	**1,830,829**	1,232,496	1,103,963
Purchased power --			
Non-affiliates	**408,563**	304,978	258,621
Affiliates	**761,466**	671,098	516,944
Other operations	**949,722**	902,167	827,972
Maintenance	**531,168**	498,114	419,206
Depreciation and amortization	**504,248**	275,488	349,984
Taxes other than income taxes	**259,825**	227,806	212,827
Total operating expenses	**5,245,821**	4,112,147	3,689,517
Operating Income	**1,388,382**	1,258,661	1,223,990
Other Income and (Expense):			
Allowance for equity funds used during construction	**26,808**	26,659	10,752
Interest income	**6,281**	6,657	15,625
Interest expense, net of amounts capitalized	**(221,199)**	(182,370)	(182,583)
Interest expense to affiliate trusts	**(59,510)**	(44,565)	-
Distributions on mandatorily redeemable preferred securities	**-**	(15,839)	(59,675)
Other income (expense), net	**5,742**	(11,362)	(10,551)
Total other income and (expense)	**(241,878)**	(220,820)	(226,432)
Earnings Before Income Taxes	**1,146,504**	1,037,841	997,558
Income taxes	**430,812**	379,170	366,311
Net Income	**715,692**	658,671	631,247
Dividends on Preferred Stock	**693**	670	670
Net Income After Dividends on Preferred Stock	**$714,999**	$658,001	$630,577

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2005, 2004, and 2003
Georgia Power Company 2005 Annual Report

	2005	2004	2003
		(in thousands)	
Operating Activities:			
Net income	**$ 715,692**	$ 658,671	$ 631,247
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization	**592,264**	361,958	424,321
Deferred income taxes and investment tax credits, net	**231,708**	251,623	199,265
Deferred expenses - affiliates	**1,268**	(10,563)	(7,399)
Allowance for equity funds used during construction	**(26,808)**	(26,659)	(10,752)
Pension, postretirement, and other employee benefits	**(19,468)**	(15,868)	(30,225)
Tax benefit of stock options	**15,711**	9,701	11,649
Other, net	**(11,068)**	(19,764)	18,929
Changes in certain current assets and liabilities --			
Receivables	**(591,498)**	(227,204)	(4,395)
Fossil fuel stock	**2,528**	(46,730)	(17,490)
Materials and supplies	**(53,942)**	618	(7,677)
Prepaid income taxes	**(43,626)**	14,358	(3,951)
Other current assets	**4,108**	(23,672)	1,599
Accounts payable	**110,118**	132,001	(62,553)
Accrued taxes	**85,098**	(64,563)	52,348
Accrued compensation	**3,822**	(6,664)	(3,111)
Other current liabilities	**33,289**	5,836	19,845
Net cash provided from operating activities	**1,049,196**	993,079	1,211,650
Investing Activities:			
Property additions	**(842,870)**	(741,151)	(717,993)
Nuclear decommissioning trust fund purchases	**(381,235)**	(541,048)	(656,806)
Nuclear decommissioning trust fund sales	**372,536**	532,349	648,107
Purchase of property from affiliates	**-**	(339,750)	(2)
Cost of removal net of salvage	**(29,428)**	(21,756)	(28,265)
Change in construction payables, net of joint owner portion	**4,037**	413	(32,223)
Other	**(315)**	(4,961)	1,008
Net cash used for investing activities	**(877,275)**	(1,115,904)	(786,174)
Financing Activities:			
Increase (decrease) in notes payable, net	**59,509**	70,956	(220,400)
Proceeds --			
Senior notes	**625,000**	600,000	1,000,000
Pollution control bonds	**185,000**	-	-
Mandatorily redeemable preferred securities	**-**	200,000	-
Capital contributions from parent company	**149,034**	260,068	40,809
Redemptions --			
Pollution control bonds	**(185,000)**	-	-
Senior notes	**(450,000)**	(200,000)	(665,000)
Mandatorily redeemable preferred securities	**-**	(200,000)	-
Payment of preferred stock dividends	**(546)**	(654)	(696)
Payment of common stock dividends	**(556,100)**	(565,500)	(565,800)
Other	**(21,679)**	(17,247)	(22,563)
Net cash provided from (used for) financing activities	**(194,782)**	147,623	(433,650)
Net Change in Cash and Cash Equivalents	**(22,861)**	24,798	(8,174)
Cash and Cash Equivalents at Beginning of Year	**33,497**	8,699	16,873
Cash and Cash Equivalents at End of Year	**$ 10,636**	$ 33,497	$ 8,699
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $10,871, $8,920, and $5,428 capitalized, respectively)	**$250,445**	$228,190	$215,463
Income taxes (net of refunds)	**207,973**	127,115	145,048

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

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BALANCE SHEETS
At December 31, 2005 and 2004
Georgia Power Company 2005 Annual Report

Assets	2005	2004
		(in thousands)
Current Assets:		
Cash and cash equivalents	**$ 10,636**	$ 33,497
Receivables --		
Customer accounts receivable	**418,154**	317,937
Unbilled revenues	**141,875**	140,027
Under recovered regulatory clause revenues	**454,683**	345,542
Other accounts and notes receivable	**110,397**	94,377
Affiliated companies	**84,597**	17,042
Accumulated provision for uncollectible accounts	**(8,647)**	(7,100)
Fossil fuel stock, at average cost	**181,739**	184,267
Vacation pay	**59,190**	57,372
Materials and supplies, at average cost	**323,908**	270,422
Prepaid expenses	**70,825**	32,695
Other	**50,248**	28,262
Total current assets	**1,897,605**	1,514,340
Property, Plant, and Equipment:		
In service	**19,603,249**	18,681,533
Less accumulated provision for depreciation	**7,575,926**	7,217,607
	12,027,323	11,463,926
Nuclear fuel, at amortized cost	**134,798**	124,745
Construction work in progress	**563,155**	766,140
Total property, plant, and equipment	**12,725,276**	12,354,811
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**68,188**	66,192
Nuclear decommissioning trusts, at fair value	**486,591**	459,194
Other	**71,468**	64,571
Total other property and investments	**626,247**	589,957
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**500,882**	505,664
Prepaid pension costs	**476,458**	450,270
Deferred under recovered regulatory clause revenues	**295,116**	-
Other regulatory assets	**330,483**	246,462
Other	**195,716**	160,834
Total deferred charges and other assets	**1,798,655**	1,363,230
Total Assets	**$17,047,783**	$15,822,338

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

BALANCE SHEETS
At December 31, 2005 and 2004
Georgia Power Company 2005 Annual Report

Liabilities and Stockholder's Equity	2005	2004
		(in thousands)
Current Liabilities:		
Securities due within one year	$ 167,317	$ 452,498
Notes payable	267,743	208,233
Accounts payable --		
Affiliated	285,019	194,253
Other	360,455	310,763
Customer deposits	129,293	115,661
Accrued taxes --		
Income taxes	150,896	78,269
Other	204,778	129,520
Accrued interest	88,885	74,529
Accrued vacation pay	45,602	44,894
Accrued compensation	137,303	127,340
Other	120,312	83,632
Total current liabilities	1,957,603	1,819,592
Long-term Debt (See accompanying statements)	4,179,218	3,709,852
Long-term Debt Payable to Affiliated Trusts (See accompanying statements)	969,073	969,073
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	2,730,303	2,556,040
Deferred credits related to income taxes	158,759	170,973
Accumulated deferred investment tax credits	287,726	300,018
Employee benefit obligations	358,137	331,002
Asset retirement obligations	627,465	504,515
Other cost of removal obligations	404,614	411,692
Other regulatory liabilities	97,015	84,678
Other	63,335	59,733
Total deferred credits and other liabilities	4,727,354	4,418,651
Total Liabilities	11,833,248	10,917,168
Preferred Stock (See accompanying statements)	-	14,609
Common Stockholder's Equity (See accompanying statements)	5,214,535	4,890,561
Total Liabilities and Stockholder's Equity	$17,047,783	$15,822,338
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2005 and 2004
Georgia Power Company 2005 Annual Report

	2005	2004	2005	2004
	(in thousands)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable --				
5.50% due December 1, 2005	**$ -**	$ 150,000		
Variable rate (1.66% to 1.96% at 1/1/05) due 2005	**-**	300,000		
6.20% due February 1, 2006	**150,000**	150,000		
4.875% due July 15, 2007	**300,000**	300,000		
4.10% due August 15, 2009	**125,000**	125,000		
Variable rate (4.53% at 1/1/06) due 2009	**150,000**	150,000		
4.00% to 6.00% due 2011-2045	**1,850,000**	1,225,000		
Total long-term notes payable	**2,575,000**	2,400,000		
Other long-term debt --				
Pollution control revenue bonds -- non-collateralized:				
2.83% to 5.45% due 2012-2034	**812,560**	812,560		
Variable rate (2.82% to 3.08% at 1/1/06) due 2011-2032	**873,330**	873,330		
Total other long-term debt	**1,685,890**	1,685,890		
Capitalized lease obligations	**74,484**	76,982		
Unamortized debt premium (discount), net	**(3,448)**	(522)		
Total long-term debt (annual interest requirement -- $205.5 million)	**4,331,926**	4,162,350		
Less amount due within one year	**152,708**	452,498		
Long-term debt excluding amount due within one year	**4,179,218**	3,709,852	**40.3%**	38.7%
Long-term Debt Payable to Affiliated Trusts:				
4.88% to 7.13% due 2042 (annual interest requirement -- $59.5 million)	**969,073**	**969,073**	**9.4**	10.1
Cumulative Preferred Stock:				
$100 stated value at 4.60%				
Authorized -- 5,000,000 shares				
Outstanding -- 145,689 shares (annual dividend requirement -- $0.7 million)	**14,609**	14,609		
Less amount due within one year	**14,609**	-		
Total cumulative preferred stock excluding amount due within one year	**-**	14,609	**0.0**	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	**2,643,012**	2,478,268		
Retained earnings	**2,261,698**	2,102,798		
Accumulated other comprehensive income (loss)	**(34,425)**	(34,755)		
Total common stockholder's equity	**5,214,535**	4,890,561	**50.3**	51.0
Total Capitalization	**$10,362,826**	$9,584,095	**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, 2005, 2004, and 2003

Georgia Power Company 2005 Annual Report

	Common Stock	Paid-In Capital	Retained Earnings	Other Comprehensive Income (loss)	Total
			(in thousands)		
Balance at December 31, 2002	$344,250	$2,156,080	$1,945,520	$(11,403)	$4,434,447
Net income after dividends on preferred stock	-	-	630,577	-	630,577
Capital contributions from parent company	-	52,458	-	-	52,458
Other comprehensive income (loss)	-	-	-	(11,471)	(11,471)
Cash dividends on common stock	-	-	(565,800)	-	(565,800)
Balance at December 31, 2003	**344,250**	**2,208,538**	**2,010,297**	**(22,874)**	**4,540,211**
Net income after dividends on preferred stock	-	-	658,001	-	658,001
Capital contributions from parent company	-	269,769	-	-	269,769
Other comprehensive income (loss)	-	-	-	(11,881)	(11,881)
Cash dividends on common stock	-	-	(565,500)	-	(565,500)
Other	-	(39)	-	-	(39)
Balance at December 31, 2004	**344,250**	**2,478,268**	**2,102,798**	**(34,755)**	**4,890,561**
Net income after dividends on preferred stock	-	-	**714,999**	-	**714,999**
Capital contributions from parent company	-	**164,745**	-	-	**164,745**
Other comprehensive income (loss)	-	-	-	**330**	**330**
Cash dividends on common stock	-	-	**(556,100)**	-	**(556,100)**
Other	-	**(1)**	**1**	-	-
Balance at December 31, 2005	**$344,250**	**$2,643,012**	**$2,261,698**	**$(34,425)**	**$5,214,535**

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

STATEMENTS OF COMPREHENSIVE INCOME

For the Years Ended December 31, 2005, 2004, and 2003

Georgia Power Company 2005 Annual Report

	2005	2004	2003
		(in thousands)	
Net income after dividends on preferred stock	**$714,999**	$658,001	$630,577
Other comprehensive income (loss):			
Change in additional minimum pension liability, net of tax of $(1,981), $(3,861) and $(5,133), respectively	**(3,140)**	(6,122)	(8,138)
Change in fair value of marketable securities, net of tax of $317 and $(114)	**501**	(181)	-
Changes in fair value of qualifying hedges, net of tax of $1,214, $(5,046) and $(3,241), respectively	**1,925**	(7,999)	(5,550)
Less: Reclassification adjustment for amounts included in net income, net of tax of $848, $1,528 and $1,208, respectively	**1,044**	2,421	2,217
Total other comprehensive income (loss)	**330**	(11,881)	(11,471)
Comprehensive Income	**$715,329**	$646,120	$619,106

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Georgia Power Company (Company) is a wholly owned subsidiary of Southern Company, which is the parent company of five retail operating companies, Southern Power Company (Southern Power), Southern Company Services (SCS), Southern Communications Services (SouthernLINC Wireless), Southern Company Holdings (Southern Holdings), Southern Nuclear Operating Company (Southern Nuclear), Southern Telecom, and other direct and indirect subsidiaries. The retail operating companies -- Alabama Power, the Company, Gulf Power, Mississippi Power, and Savannah Electric -- provide electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast. Southern Power constructs, owns, and manages Southern Company's competitive generation assets and sells electricity at market-based rates in the wholesale market. Contracts among the retail operating companies and Southern Power -- related to jointly owned generating facilities, interconnecting transmission lines, or the exchange of electric power -- are regulated by the Federal Energy Regulatory Commission (FERC). SCS -- the system service company -- provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications services to the retail operating companies and also markets these services to the public within the Southeast. Southern Telecom provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding subsidiary for Southern Company's investments in synthetic fuels and leveraged leases and various other energy-related businesses. Southern Nuclear operates and provides services to Southern Company's nuclear power plants. In January 2006, Southern Company completed the sale of substantially all the assets of Southern Company Gas, its competitive retail natural gas marketing subsidiary.

The equity method is used for subsidiaries in which the Company has significant influence but does not control and for variable interest entities where the Company is not the primary beneficiary. Certain prior years' data presented in the financial statements have been reclassified to conform to current year presentation.

Southern Company was registered as a holding company under the Public Utility Holding Company Act of 1935, as amended (PUHCA), until its repeal on February 8, 2006, and Southern Company and its subsidiaries, including the Company, were subject to the regulatory provisions of the PUHCA. The Company is subject to regulation by the FERC and the Georgia Public Service Commission (PSC). The Company follows accounting principles generally accepted in the United States and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires the use of estimates and the actual results may differ from those estimates.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, purchasing, accounting and statistical analysis, finance and treasury, tax, information resources, marketing, auditing, insurance and pension administration, human resources, systems and procedures, and other services with respect to business and operations and power pool operations. Costs for these services amounted to $330 million in 2005, $292 million in 2004, and $303 million in 2003. Cost allocation methodologies used by SCS were approved by the Securities and Exchange Commission prior to the repeal of the PUHCA 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 $328 million in 2005, $311 million in 2004, and $289 million in 2003.

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. Billings under these agreements with Southern Power amounted to $5.2 million in 2005, $4.8 million in 2004, and $5.3 million in 2003.

The Company has an agreement with SouthernLINC Wireless under which the Company receives digital wireless communications services and purchases digital equipment. Costs for these services amounted to $7.3 million in 2005, $7.7 million in 2004, and $7.4 million in 2003.

Southern Company holds a 30 percent ownership in Alabama Fuel Products, LLC (AFP), which produces synthetic fuel. The Company has an agreement with an indirect subsidiary of Southern Company that provides services for AFP. Under this agreement, the Company provides certain accounting functions, including processing and paying fuel transportation invoices, and the Company is reimbursed for its expenses. Amounts billed under this agreement totaled approximately $61 million in 2005, $53 million in 2004, and $38 million in 2003. In addition, the Company purchases synthetic fuel from AFP for use at plants Branch, McDonough, and Bowen. Fuel purchases totaled $216 million in 2005, $163 million in 2004, and $91 million in 2003.

The Company has entered into several purchased power agreements (PPAs) with Southern Power for capacity and energy. Expenses associated with these PPAs were $419 million, $282 million, and $203 million in 2005, 2004, and 2003, respectively. Additionally, the Company recorded a reduction of $1 million and an increase of $11 million of prepaid capacity expenses included on the balance sheets at December 31, 2005 and 2004, respectively. See Note 7 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, the Company operates Plant Scherer, and Gulf Power reimburses the Company for its proportionate share of the related expenses which were $4.3 million in 2005, $6.8 million in 2004, and $4.9 million in 2003. The Company has an agreement with Savannah Electric under which the Company jointly owns a portion of Plant McIntosh. Under this agreement, Savannah Electric operates Plant McIntosh, and the Company reimburses Savannah Electric for its proportionate share of the related expenses which were $5.5 million in 2005, $3.3 million in 2004, and $3.7 million in 2003. See Note 4 for additional information.

The Company provides incidental services to other Southern Company subsidiaries which are generally minor in duration and amount. However, with the hurricane damage experienced by Alabama Power, Gulf Power, and Mississippi Power in the last two years, assistance provided to aid in storm restoration, including company labor, contract labor, and materials, has caused an increase in these activities. The total amount of storm assistance provided to Alabama Power, Gulf Power, and Mississippi Power in 2005 was $4.1 million, $4.4 million, and $55 million, respectively. The total amount of storm assistance provided to Alabama Power and Gulf Power in 2004 was $4.1 million and $6.4 million, respectively. These activities were billed at cost.

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

The retail operating companies, including the Company, and Southern Power 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 7 under "Fuel Commitments" for additional information.

The Company has entered into an agreement to merge with Savannah Electric. See Note 3 under "Retail Regulatory Matters – Merger" 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.

Regulatory assets and (liabilities) reflected in the Company's balance sheets at December 31 relate to the following:

	2005	2004	Note
	(in millions)		
Deferred income tax charges	$ 501	$506	(a)
Premium on reacquired debt	170	177	(b)
Corporate building lease	52	53	(e)
Vacation pay	59	57	(d)
Postretirement benefits	18	20	(e)
DOE assessments	6	10	(c)
Generating plant outage costs	46	40	(g)
Other regulatory assets	33	11	(e)
Asset retirement obligation	65	(20)	(a)
Other cost of removal obligations	(404)	(412)	(a)
Deferred income tax credits	(159)	(171)	(a)
Environmental remediation	(19)	(22)	(f)
Purchased power	(33)	-	(f)
Other regulatory liabilities	(30)	(6)	(e)
Total	$ 305	$243	

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

(a) Asset retirement and removal liabilities are recorded, deferred income tax assets are recovered, and deferred tax liabilities are amortized over the related property lives, which may range up to 60 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities.

(b) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue which may range up to 50 years.

(c) Assessments for the decontamination and decommissioning of the DOE's nuclear fuel enrichment facilities are recorded annually from 1993 through 2006.

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

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

(f) Amortized over a three-year period ending in 2007. See Note 3 under "Retail Regulatory Matters - Rate Plans."

(g) See "Property, Plant, and Equipment" herein.

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, including plant, exists and, if impaired, write down the assets to their fair value. All regulatory assets and liabilities are reflected in rates.

Revenues

Energy and other revenues are recognized as services are provided. Unbilled revenues are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between the actual recoverable costs and amounts billed in current regulated rates.

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

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense includes the cost of purchased emission allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel. Total charges for nuclear fuel included in fuel expense amounted to $70 million in 2005, $73 million in 2004, and $74 million in 2003.

Nuclear Fuel Disposal Costs

The Company has contracts with the U.S. Department of Energy (DOE) that provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent nuclear fuel in 1998 as required by the contracts, and the Company is pursuing legal remedies against the government for breach of contract. Sufficient pool storage capacity for spent fuel is available at Plant Vogtle to maintain full-core discharge capability for both units into 2015. Construction of an on-site dry storage facility at Plant Vogtle is expected to begin in sufficient time to maintain pool full-core discharge capability. At Plant Hatch, an on-site dry storage facility is operational and can be expanded to accommodate spent fuel through the life of the plant.

Also, the Energy Policy Act of 1992 required the establishment of a Uranium Enrichment Decontamination and Decommissioning Fund, which is funded in part by a special assessment on utilities with nuclear plants. This assessment has been paid over a 15-

year period; the final installment is scheduled to occur in 2006. 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 interest, estimates its remaining liability at December 31, 2005 under this law to be approximately $4 million.

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.

Manufacturer's Tax Credits

The State of Georgia provides a tax credit for qualified investment property to manufacturing companies that construct new facilities. The credit ranges from 1 percent to 8 percent of qualified construction expenditures depending upon the county in which the new facility is located. The Company's policy is to recognize these credits when management believes that they are more likely than not to be allowed by the Georgia Department of Revenue. Manufacturer's tax credits of $12.5 million, $12.9 million, and $12.0 million were recorded in 2005, 2004, and 2003, respectively.

Property, Plant, and Equipment

The Company's property, plant, and equipment consisted of the following at December 31 (in millions):

	2005	2004
Generation	**$ 9,571**	$ 9,002
Transmission	**2,994**	2,870
Distribution	**5,953**	5,744
General	**1,057**	1,038
Plant acquisition adjustment	**28**	28
Total plant in service	**$ 19,603**	$18,682

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

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense as incurred or performed with the exception of certain generating plant maintenance costs. As mandated by the Georgia PSC, the Company defers and amortizes nuclear refueling costs over the unit's operating cycle before the next refueling. The refueling cycles are 18 and 24 months for plants Vogtle and Hatch, respectively. In accordance with the Georgia PSC 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.

Depreciation and Amortization

Depreciation of the original cost of plant in service is provided primarily by using composite straight-line rates, which approximated 2.6 percent in 2005, 2.6 percent in 2004, and 2.7 percent in 2003. Depreciation studies are conducted periodically to update the composite rates that are approved by the Georgia PSC. In connection with the new retail rate plan for the Company ending December 31, 2007 (2004 Retail Rate Plan), effective January 1, 2005, the depreciation rates were revised by the Georgia PSC. The revised depreciation rates had no material impact on the Company's financial statements.

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.

Under the three-year retail rate plan for the Company ending December 31, 2004 (2001 Retail Rate Plan), the Company discontinued recording accelerated depreciation and amortization. Also, the Company was ordered to amortize $333 million, the cumulative balance previously expensed, equally over three years as a credit to amortization expense beginning January

2002. Additionally, the Company was ordered to recognize new Georgia PSC certified purchased power costs in rates evenly over the three years covered by the 2001 Retail Rate Plan. As a result of the purchased power regulatory adjustment, the Company recorded amortization expenses of $14 million in 2003. The Company recorded a credit to amortization expense of $77 million in 2004. See Note 3 under "Retail Regulatory Matters - Rate Plans" for additional information.

Asset Retirement Obligations and Other Costs of Removal

Effective January 1, 2003, the Company adopted FASB Statement No. 143, Accounting for Asset Retirement Obligations. Statement No. 143 established new accounting and reporting standards for legal obligations associated with the ultimate costs of retiring long-lived assets. The present value of the ultimate costs for an asset's future retirement is recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In addition, effective December 31, 2005, the Company adopted the provisions of FASB Interpretation No. 47, Conditional Asset Retirement Obligations (FIN 47), which requires that an asset retirement obligation be recorded even though the timing and/or method of settlement are conditional on future events. Prior to December 2005, the Company did not recognize asset retirement obligations for asbestos removal because the timing of their retirements was dependent on future events. The Company has received approval from the Georgia PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations will continue to be reflected on the balance sheets as a regulatory liability. Therefore, the Company had no cumulative effect to net income resulting from the adoption of Statement No. 143 or FIN 47.

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. The fair value of assets legally restricted for settling retirement obligations related to nuclear facilities as of December 31, 2005 was $487 million. In addition, the Company has recognized retirement obligations related to various landfill sites, ash ponds, and underground storage tanks. The Company also recorded additional asset retirement obligations (and assets) of approximately $91 million related to asbestos removal. The Company has also identified retirement obligations related to certain transmission and distribution facilities, leasehold improvements, equipment on customer property, and property associated with the Company's rail lines. However, liabilities for the removal of these assets have not been 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 allowed removal costs in accordance with its regulatory treatment. Any difference between costs recognized under Statement No. 143 and FIN 47 and those reflected in rates are recognized as either a regulatory asset or liability in the balance sheets as ordered by the Georgia PSC. See "Nuclear Decommissioning" herein for further information on amounts included in rates.

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

	2005	2004
	(in millions)	
Balance beginning of year	**$505**	$476
Liabilities incurred	**91**	-
Liabilities settled	**(2)**	(2)
Accretion	**33**	31
Balance end of year	**$627**	$505

If FIN 47 had been adopted as of December 31, 2004, the pro forma asset retirement obligations would have been $591 million.

Nuclear Decommissioning

The Nuclear Regulatory Commission (NRC) requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has external trust funds to comply with the NRC's regulations. Use of the funds is restricted to nuclear decommissioning activities and the funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and state PSCs, as well as the Internal Revenue Service (IRS). The trust funds are invested in a tax-

efficient manner in a diversified mix of equity and fixed income securities and are classified as available-for-sale. The trust funds are included in the balance sheets at fair value, as obtained from quoted market prices for the same or similar investments. Details of the securities held in these trusts at December 31 are as follows:

2005	Unrealized Gains	Unrealized Losses	Fair Value
		(in millions)	
Equity	$76.7	$(6.3)	$325.5
Debt	2.8	(0.8)	135.3
Other	-	-	25.8
Total	**$79.5**	**$(7.1)**	**$486.6**

2004	Unrealized Gains	Unrealized Losses	Fair Value
		(in millions)	
Equity	$68.7	$(4.0)	$308.2
Debt	5.3	(0.1)	138.0
Other	-	-	13.0
Total	$74.0	$(4.1)	$459.2

The contractual maturities of debt securities at December 31, 2005 are as follows: $3.2 million in 2006; $34.9 million in 2007-2010; $32.4 million in 2011-2015; and $57.2 million thereafter.

Sales of the securities held in the trust funds resulted in proceeds of $372.5 million, $532.3 million, and $648.1 million in 2005, 2004, and 2003, respectively, all of which were re-invested. Net realized gains (losses) were $12.6 million, $14.1 million, and $21.3 million in 2005, 2004, and 2003, respectively. Realized gains and losses are determined on a specific identification basis. In accordance with regulatory guidance, all realized and unrealized gains and losses are included in the regulatory liability for Asset Retirement Obligations in the balance sheets and are not included in net income or other comprehensive income. Unrealized gains and losses are considered non-cash transactions for purposes of the statements of cash flow. Unrealized losses were not material in any period presented and do not represent any impairment of the underlying investments.

Amounts previously recorded in internal reserves are being transferred into the external trust funds over periods approved by the Georgia PSC. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed plans with the NRC to ensure that, over time -- the deposits and earnings of the external trust funds will provide the minimum funding amounts prescribed by the NRC. Annual provisions for nuclear decommissioning are based on an annuity method as approved by the Georgia PSC. The amount expensed in 2005 and fund balances were as follows:

	Plant Hatch	Plant Vogtle
	(in millions)	
Amount expensed in 2005	$ -	$ 7
Accumulated provisions:		
External trust funds, at fair value	$313	$174
Internal reserves	-	1
Total	$313	$175

Site study cost is the estimate to decommission a specific facility as of the site study year. The estimated costs of decommissioning based on the most current study performed in 2003 for the Company's ownership interests in plants Hatch and Vogtle were as follows:

	Plant Hatch	Plant Vogtle
Decommissioning periods:		
Beginning year	2034	2027
Completion year	2065	2048
	(in millions)	
Site study costs:		
Radiated structures	$497	$452
Non-radiated structures	49	58
Total	$546	$510

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

Under the 2001 Retail Rate Plan, the Georgia PSC approved the annual decommissioning costs for ratemaking of $9 million. This amount was based on the NRC generic estimate to decommission the radioactive

portion of the facilities as of 2000. The estimates were $383 million and $282 million for plants Hatch and Vogtle, respectively. Significant assumptions used to determine the costs for ratemaking included an estimated inflation rate of 4.7 percent and an estimated trust earnings rate of 6.5 percent.

Under the 2004 Retail Rate Plan, effective January 1, 2005, the Georgia PSC decreased the annual decommissioning costs for ratemaking to $7 million. This amount is based on the NRC generic estimate to decommission the radioactive portion of the facilities as of 2003. The estimates are $421 million and $326 million for plants Hatch and Vogtle, respectively. Significant assumptions used to determine the costs for ratemaking include an estimated inflation rate of 3.1 percent and an estimated trust earnings rate of 5.1 percent. Another significant assumption used was the change in the operating license for Plant Hatch. In January 2002, the NRC granted the Company a 20-year extension of the licenses for both units at Plant Hatch which permits the operation of units 1 and 2 until 2034 and 2038, respectively. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for the anticipated cost of decommissioning.

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

In accordance with regulatory treatment, the Company records AFUDC. AFUDC represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, it increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation expense. Interest related to the construction of new facilities not included in the Company's retail rates is capitalized in accordance with standard interest capitalization requirements. For the years 2005, 2004, and 2003, the average AFUDC rates were 8.02 percent, 8.22 percent, and 5.51 percent, respectively. AFUDC and interest capitalized, net of taxes, were 4.7 percent and 4.9 percent of net income after dividends on preferred stock for 2005 and 2004, respectively, and less than 3 percent for 2003.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment provision is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change. See Note 3 under "Retail Regulatory Matters" and "Plant McIntosh Construction Project" for information regarding a regulatory disallowance by the Georgia PSC in December 2004.

Storm Damage Reserve

The Company maintains a reserve for property damage to cover the cost of damages from major storms to its transmission and distribution lines and the cost of uninsured damages to its generation facilities and other property as mandated by the Georgia PSC. The Company accrues $6.3 million annually that is recoverable through base rates. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for storm damage costs.

Environmental Cost Recovery

Under Georgia PSC ratemaking provisions, $22 million has been deferred in a regulatory liability account related to certain environmental insurance settlements. Under the 2004 Retail Rate Plan, this regulatory liability is being amortized over a three-year period beginning January 1, 2005. However, the Georgia PSC also approved an annual environmental accrual of $5.4 million. Environmental remediation expenditures are charged against the reserve as they are incurred. The annual accrual amount will be reviewed and adjusted in future regulatory proceedings.

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 average costs 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.

Fuel Inventory

Fuel inventory includes the average costs of oil, coal, natural gas, and emission allowances. Fuel is charged to inventory when purchased and then expensed as used. Emission allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Stock Options

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

For pro forma purposes, the Company generally recognizes stock option expense on a straight-line basis over the vesting period. Stock options granted to employees who are eligible for retirement are expensed at the grant date.

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

Net Income	As Reported	Options Impact	Pro Forma
		(in millions)	
2005	**$715**	**$(3)**	**$712**
2004	$658	(3)	$655
2003	$631	(4)	$627

The estimated fair value of stock options granted in 2005, 2004, and 2003 was derived using the Black-Scholes stock option pricing model. The following table shows the assumptions and the weighted average fair values of stock options.

	2005	2004	2003
Interest rate	**3.90%**	3.10%	2.70%
Average expected life of stock options (in years)	**5.0**	5.0	4.3
Expected volatility of common stock	**17.90%**	19.60%	23.60%
Expected annual dividends on common stock	**$1.43**	$1.40	$1.37
Weighted average fair value of stock options granted	**$3.90**	$3.29	$3.59

See Note 8 for additional information.

Financial Instruments

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

through current period income and are recorded on a net basis in the statements of income.

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

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

	Carrying Amount	Fair Value
Long-term debt:	(in millions)	
2005	**$5,227**	**$5,195**
2004	$5,055	$5,125

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

Comprehensive Income

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

Variable Interest Entities

The primary beneficiary of a variable interest entity must consolidate the related assets and liabilities. The Company has established certain wholly-owned trusts to issue preferred securities. However, the Company is not the primary beneficiary of the trusts. Therefore, the investments in these trusts are reflected as Other Investments, and the related loans from the trusts are reflected as Long-Term Debt Payable to Affiliated Trusts on the balance sheets. See Note 6 under "Mandatorily Redeemable Preferred Securities/Long-Term Debt Payable to Affiliated Trusts" for additional information.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. The plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). In 2005, the plan was amended to provide an additional monthly supplement to certain retirees. No contributions to the plan are expected for the year ending December 31, 2006. The Company also provides certain non-qualified benefit plans for a selected group of management and highly compensated employees. Benefits under these non-qualified plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees. The Company funds related trusts to the extent required by the Georgia PSC and the FERC. For the year ended December 31, 2006, such contributions are expected to total approximately $18.4 million. The measurement date for plan assets and obligations is September 30 for each year presented.

Pension Plans

The accumulated benefit obligation for the pension plans was $1.9 billion in 2005 and $1.7 billion in 2004. Changes during the year in the projected benefit obligations, accumulated benefit obligations, and the fair value of plan assets was as follows:

	Projected Benefit Obligation	
	2005	2004
	(in millions)	
Balance at beginning of year	**$1,885**	$1,727
Service cost	**45**	42
Interest cost	**106**	101
Benefits paid	**(85)**	(85)
Plan amendments	**13**	1
Actuarial loss	**91**	99
Balance at end of year	**$2,055**	$1,885

	Plan Assets	
	2005	2004
	(in millions)	
Balance at beginning of year	**$2,181**	$2,055
Actual return on plan assets	**339**	207
Benefits paid	**(80)**	(81)
Balance at end of year	**$2,440**	$2,181

In 2005, the projected benefit obligations for the qualified and non-qualified pension plans were $1.945 billion and $110 million, respectively. All plan assets are related to the qualified plan.

Pension plan assets are managed and invested in accordance with all applicable requirements including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity, as described in the table below. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes.

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

	Plan Assets		
	Target	**2005**	2004
Domestic equity	36%	**40%**	36%
International equity	24	**24**	20
Fixed income	15	**17**	26
Real estate	15	**13**	10
Private equity	10	**6**	8
Total	100%	**100%**	100%

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

	2005	2004
	(in millions)	
Funded status	**$385**	$295
Unrecognized transition amount	**(4)**	(8)
Unrecognized prior service cost	**109**	108
Unrecognized net actuarial gain (loss)	**(54)**	21
Prepaid pension asset, net	**$436**	$416

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

	2005	2004
	(in millions)	
Prepaid pension asset	**$476**	$450
Employee benefit obligations	**(96)**	(89)
Other property and investments	**15**	19
Accumulated other comprehensive income	**41**	36
Prepaid pension asset, net	**$436**	$416

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

	2005	2004	2003
	(in millions)		
Service cost	**$ 45**	$ 42	$ 38
Interest cost	**106**	101	100
Expected return on plan assets	**(182)**	(180)	(179)
Recognized net (gain)/loss	**3**	(5)	(19)
Net amortization	**7**	7	6
Net pension (income)	**$(21)**	$(35)	$ (54)

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2005, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2006	$ 88
2007	91
2008	94
2009	97
2010	102
2011 to 2015	$607

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	
	2005	2004
	(in millions)	
Balance at beginning of year	**$726**	$723
Service cost	**10**	10
Interest cost	**41**	41
Benefits paid	**(32)**	(31)
Actuarial loss	**24**	42
Plan amendments	**-**	(59)
Balance at end of year	**$769**	$726

	Plan Assets	
	2005	2004
	(in millions)	
Balance at beginning of year	**$299**	$265
Actual return on plan assets	**38**	32
Employer contributions	**40**	33
Benefits paid	**(32)**	(31)
Balance at end of year	**$345**	$299

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

		Plan Assets	
	Target	**2005**	2004
Domestic equity	43%	**43%**	42%
International equity	21	**22**	23
Domestic fixed income	19	**19**	19
Global fixed income	11	**11**	11
Real estate	4	**3**	3
Private equity	2	**2**	2
Total	100%	**100%**	100%

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

	2005	2004
	(in millions)	
Funded status	**$(424)**	$(428)
Unrecognized transition obligation	**70**	78
Unrecognized prior service cost	**25**	27
Unrecognized net loss	**203**	203
Fourth quarter contributions	**21**	15
Employee benefit obligations recognized in the balance sheets	**$(105)**	$(105)

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

	2005	2004	2003
	(in millions)		
Service cost	**$10**	$ 10	$ 9
Interest cost	**41**	41	40
Expected return on plan assets	**(22)**	(25)	(24)
Net amortization	**18**	18	16
Net postretirement cost	**$47**	$ 44	$ 41

In the third quarter 2004, the Company prospectively adopted FASB Staff Position (FSP) 106-2, Accounting and Disclosure Requirements related to the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (Medicare Act). The Medicare Act provides a 28 percent prescription drug subsidy for Medicare eligible retirees. FSP 106-2 requires recognition of the impacts of the Medicare Act in the accumulated postretirement benefit obligation (APBO) and future cost of service for postretirement medical plans. The effect of the subsidy reduced the Company's expenses for the six months ended December 31, 2004 and for the year ended December 31, 2005 by approximately $5 million and $10 million, respectively, and is expected to have a similar impact on future expenses.

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the accumulated benefit obligation for the postretirement plans. Estimated benefit payments are reduced by drug

subsidy receipts expected as a result of the Medicare Act as follows:

	Benefit Payments	Subsidy Receipts	Total
	(in millions)		
2006	$ 37	$ (3)	$ 34
2007	39	(4)	35
2008	42	(4)	38
2009	46	(4)	42
2010	50	(5)	45
2011 to 2015	280	(34)	246

Actuarial Assumptions

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

	2005	2004	2003
Discount	**5.50%**	5.75%	6.00%
Annual salary increase	**3.00**	3.50	3.75
Long-term return on plan assets	**8.50**	8.50	8.50

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

An additional assumption used in measuring the APBO was a weighted average medical care cost trend rate of 10.25 percent for 2005, decreasing gradually to 4.75 percent through the year 2014, 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, 2005, as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$70	$62
Service and interest costs	5	4

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides a 75 percent matching contribution up to 6 percent of an employee's base salary. Total matching contributions made to the plan for the years 2005, 2004, and 2003 were $19 million, $18 million, and $18 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, and citizen enforcement of environmental requirements such as opacity and other air quality standards, 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 pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S District Court for the Northern District of Georgia against the Company and Alabama Power, alleging that the Company and Alabama Power had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws with respect to certain coal-fired generating facilities. Through subsequent amendments and other legal proceedings, the EPA added Savannah Electric as a defendant to the original action and filed a separate action against Alabama Power after it was dismissed from the original action. In these lawsuits, the

EPA alleges that NSR violations occurred at eight coal-fired generating facilities, including the Company's Plants Bowen and Scherer. The civil action requests penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. On June 3, 2005, the U.S. District for the Northern District of Alabama issued a decision in favor of Alabama Power on two primary legal issues in the case; however, the decision does not resolve the case, nor does it address other legal issues associated with the EPA's allegations. In accordance with a separate court order, Alabama Power and the EPA are currently participating in mediation with respect to the EPA's claims. The action against the Company and Savannah Electric has been administratively closed since the spring of 2001, and none of the parties has sought to reopen the case.

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $32,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in this case could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

Plant Wansley Environmental Litigation

In December 2002, the Sierra Club, Physicians for Social Responsibility, Georgia Forestwatch, and one individual filed a civil suit in the U.S. District Court for the Northern District of Georgia against the Company for alleged violations of the Clean Air Act at four of the units at Plant Wansley. 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. The liability phase of the case has concluded with the court ruling in favor of the Company in part and the plaintiffs in part. In March 2005, the U.S. Court of Appeals for the Eleventh Circuit accepted the Company's petition for review of the district court's order, and oral arguments were held on January 24, 2006. The district court case has been administratively closed pending that appeal. If necessary, the district court will hold a separate trial which will address civil penalties and possible injunctive relief requested by the plaintiffs. The ultimate outcome of this matter cannot currently be determined; however, an adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

Environmental Remediation

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. In 1995, the EPA designated the Company and four other unrelated entities as potentially responsible parties at a site in Brunswick, Georgia that is listed on the federal National Priorities List. As of December 31, 2005, the Company had recorded approximately $6 million in cumulative expenses associated with the Company's agreed-upon share of the removal and remedial investigation and feasibility study costs for the Brunswick site. Additional claims for recovery of natural resource damages at the site are anticipated. The Company has also recognized $36 million in cumulative expenses through December 31, 2005 for the assessment and anticipated cleanup of sites on the Georgia Hazardous Sites Inventory.

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 the Company'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.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates at market-based prices. The Company also has FERC authority to make short-term opportunity sales at market rates. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in that proceeding. In February 2005, Southern Company submitted responsive information. In February 2006, the FERC agreed to allow the parties to conduct settlement discussions. Any new market-based rate transactions in its retail service territory entered into after February 27, 2005 are subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. The impact of such sales through December 31, 2005 is not expected to exceed $4.9 million. The refund period covers 15 months. In the event that the FERC's default mitigation measures for entities that are found to have market power are ultimately applied, the Company may be required to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates. The final outcome of this matter will depend on the form in which the final methodology for assessing generation market power and mitigation rules may be ultimately adopted and cannot be determined at this time.

In addition, in May 2005, the FERC started an investigation to determine whether Southern Company satisfies the other three parts of the FERC's market-based rate analysis: transmission market power, barriers to entry, and affiliate abuse or reciprocal dealing. The FERC established a new refund period related to this expanded investigation. Any and all new market-based rate transactions both inside and outside Southern Company's retail service territory involving any Southern Company subsidiary, including the Company, will be subject to refund to the extent the FERC orders lower rates as a result of this new investigation, with the 15-month refund period beginning July 19, 2005. The impact of such sales through December 31, 2005 is not expected to exceed $10.9 million, of which $3.2 million relates to sales inside the retail service territory as discussed above. The FERC also directed that this expanded proceeding be held in abeyance pending the outcome of the proceeding on the IIC discussed below.

The Company believes that there is no meritorious basis for this proceeding and is vigorously defending itself in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in this proceeding, cannot now be determined.

Intercompany Interchange Contract

The Company's generation fleet in its retail service territory is operated under the IIC, as approved by the FERC. In May 2005, the FERC also initiated a new proceeding to examine (1) the provisions of the IIC among Alabama Power, the Company, Gulf Power, Mississippi Power, Savannah Electric, Southern Power, and SCS, as agent, under the terms of which the power pool of Southern Company is operated, and, in particular, the propriety of the continued inclusion of Southern Power as a party to the IIC, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining Southern Power as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of Southern Power, the FERC authorized Southern Power's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct. The FERC order directs that the administrative law judge who presided over the McIntosh PPA proceeding involving an approval of PPAs between Southern Power and the Company and Savannah Electric, be assigned to preside over the hearing in this proceeding and that the testimony and exhibits presented in that proceeding be preserved to the extent appropriate. Hearings are scheduled for September 2006. Effective July 19, 2005, revenues from transactions under the IIC involving any Southern Company subsidiaries, including the Company, are subject to refund to the extent the FERC orders any changes to the IIC.

The Company believes that there is no meritorious basis for this proceeding and is vigorously defending itself in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in this proceeding, cannot now be determined.

Generation Interconnection Agreements

In July 2003, the FERC issued its final rule on the standardization of generation interconnection agreements and procedures (Order 2003). Order 2003 shifts much of the financial burden of new transmission investment from the generator to the transmission provider. The FERC has indicated that Order 2003, which was effective January 20, 2004, is to be applied prospectively to interconnection

agreements. Subsidiaries of Tenaska, Inc., as counterparties to previously executed interconnection agreements with the Company and another Southern Company subsidiary, have filed complaints at the FERC requesting that the FERC modify the agreements and that the Company refund a total of $7.9 million previously paid for interconnection facilities, with interest. The Company has opposed such relief and the proceedings are still pending. The impact of Order 2003 and its subsequent rehearings on the Company and the final results of these matters cannot be determined at this time.

Race Discrimination Litigation

In July 2000, a lawsuit alleging race discrimination was filed by three of the Company's employees against the Company, Southern Company, and SCS in the Superior Court of Fulton County, Georgia. Shortly thereafter, the lawsuit was removed to the U.S. District Court for the Northern District of Georgia and amended to add four more plaintiffs. The lawsuit also raised claims on behalf of a purported class. The plaintiffs sought compensatory and punitive damages in an unspecified amount, as well as injunctive relief.

Following various court decisions in favor of the defendants and subsequent appeals by the plaintiffs, on July 13, 2005, the plaintiffs filed a petition for writ of certiorari to the U.S. Supreme Court. On October 17, 2005, the petition was denied. This matter is now concluded.

Right of Way Litigation

Southern Company and certain of its subsidiaries, including the Company, Gulf Power, Mississippi Power, and Southern Telecom, have been named as defendants in numerous lawsuits brought by landowners since 2001. 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 exceed the easements or other property rights held by defendants. The plaintiffs assert claims for, among other things, trespass and unjust enrichment, and seek compensatory and punitive damages and injunctive relief. Management believes that the Company has complied with applicable laws and that the plaintiffs' claims are without merit.

In January 2005, the Superior Court of Decatur County, Georgia granted partial summary judgment in a lawsuit brought by landowners against the Company based on the plaintiffs' declaratory judgment claim that the easements do not permit general telecommunications use. The Company appealed this ruling to the Georgia Court of Appeals. The Georgia Court of Appeals reversed, in part, the court's order and remanded the case to the trial court for the determination of further issues. After the Court of Appeals' decision, the plaintiffs filed a motion for reconsideration, which was denied, and a petition for certiorari to the Georgia Supreme Court, which is currently pending. The question of damages and other liabilities or remedies issues with respect to this action, if any, will be decided at a future trial. In the event of an adverse verdict in the case, the Company could appeal both liability and damages or other relief granted. An adverse outcome in these matters could result in substantial judgments; however, the final outcome cannot now be determined.

In addition, in late 2001, certain subsidiaries of Southern Company, including Alabama Power, the Company, Gulf Power, Mississippi Power, Savannah Electric, and Southern Telecom, were named as defendants in a lawsuit brought by a telecommunications company that uses certain of the defendants' rights of way. This lawsuit alleges, among other things, that the defendants are contractually obligated to indemnify, defend, and hold harmless the telecommunications company from any liability that may be assessed against it in pending and future right of way litigation. The Company believes that the plaintiff's claims are without merit. In the fall of 2004, the trial court stayed the case until resolution of the underlying landowner litigation discussed above. In January 2005, the Georgia Court of Appeals dismissed the telecommunications company's appeal of the trial court's order for lack of jurisdiction. An adverse outcome in this matter, combined with an adverse outcome against the telecommunications company in one or more of the right of way lawsuits, could result in substantial judgments; however, the final outcome of these matters cannot now be determined.

Property Tax Dispute

The Company is involved in a significant property tax dispute with Monroe County, Georgia (Monroe County). The Monroe County Board of Tax Assessors (Monroe Board) has issued assessments reflecting substantial

increases in the ad valorem tax valuation of the Company's 22.95 percent ownership interest in Plant Scherer, which is located in Monroe County, for tax years 2003, 2004, and 2005. The Company is aggressively pursuing administrative appeals in Monroe County and has filed notices of arbitration for all three years. The appeals are currently stayed, pending the outcome of the litigation discussed below.

In November 2004, the Company filed suit, on its behalf, against the Monroe Board in the Superior Court of Monroe County. The Company contends that Monroe County acted without statutory authority in changing the valuation of a centrally assessed utility as established by the Revenue Commissioner of the State of Georgia and requests injunctive relief prohibiting Monroe County and the Monroe Board from unlawfully changing the value of Plant Scherer and ultimately collecting additional ad valorem taxes from the Company. On December 22, 2005, the court granted Monroe County's motion for summary judgment. The Company has filed an appeal of the Superior Court's decision to the Georgia Supreme Court.

If the Company is not successful in its administrative appeals and if Monroe County is successful in defending the litigation, the Company could be subject to total additional taxes through December 31, 2005 of up to $13 million, plus penalties and interest. The ultimate outcome of this matter cannot currently be determined.

Retail Regulatory Matters

Merger

On December 13, 2005, the Company and Savannah Electric entered into an Agreement and Plan of Merger. Savannah Electric will merge into the Company, with the Company continuing as the surviving corporation (the Merger). At the effective time of the Merger, each share of the Company's common stock will remain issued and outstanding; each share of the Company's preferred stock issued and outstanding will have been redeemed prior to the Merger; the issued and outstanding shares of Savannah Electric common stock, all of which are held by Southern Company, will be converted into the right to receive 1,500,000 shares of the Company's common stock; and each share of Savannah Electric preferred stock issued and outstanding immediately prior to the Merger will be converted into the right to receive one share of a new series of the Company's Class A Preferred Stock. The Merger must be approved by the preferred shareholders of Savannah Electric and is subject to the receipt of certain regulatory approvals from the FERC, the Georgia PSC, and the Federal Communications Commission. Pending regulatory approvals, the Merger is expected to be completed by July 2006. The Merger is not expected to have a material impact on the Company's financial statements.

While the Georgia PSC does not have specific approval authority over the merger of electric utilities, the Company and Savannah Electric have filed an application with the Georgia PSC with respect to certain approvals that will be necessary to effectively complete the Merger. In particular, the Company and Savannah Electric plan to seek the approval of the Georgia PSC with respect to the following matters:

- the transfer of Savannah Electric's generating facilities and certification of the generating facilities as the Company's assets;
- amendments to the Company's Integrated Resource Plan to add the current Savannah Electric's customers and generating facilities;
- the transfer of Savannah Electric's assigned service territory to the Company;
- adoption of the Company's service rules and regulations to the current Savannah Electric customers;
- new fuel rate and base rate schedules that would apply to the Company's sale of electricity to the current Savannah Electric customers;
- adoption of a "merger transition adjustment" rate that would be used to more closely align Savannah Electric's existing base rates to those of the Company and a "merger transition credit" rate that would credit the additional revenues collected from former Savannah Electric customers to the Company's existing customers; and
- the issuance of additional shares of the Company's common stock to Southern Company in exchange for Southern Company's shares of Savannah Electric common stock.

Rate Plans

Under the terms of the 2004 Retail Rate Plan, which the Georgia PSC approved in December 2004, the Company's earnings are evaluated against a retail return on common equity (ROE) range of 10.25 percent to 12.25 percent. Two-thirds of any earnings

above 12.25 percent will be applied to rate refunds, with the remaining one-third retained by the Company. Retail rates were increased by approximately $194 million and customer fees by approximately $9 million effective January 1, 2005 to cover the higher costs of purchased power; operating and maintenance expenses; environmental compliance; and continued investment in new generation, transmission, and distribution facilities to support growth and ensure reliability. In 2005, the Company recorded $2.7 million in revenue subject to refund related to earnings in excess of 12.25 percent retail ROE.

The Company is required to file a general rate case by July 1, 2007, in response to which the Georgia PSC would be expected to determine whether the rate order should be continued, modified, or discontinued. Until then, the Company may not file for a general base rate increase unless its projected retail ROE falls below 10.25 percent.

Under the 2001 Retail Rate Plan, retail rates were decreased by $118 million effective January 1, 2002. Under the terms of the 2001 Retail Rate Plan, earnings were evaluated against a retail ROE range of 10 percent to 12.95 percent. Two-thirds of any earnings above the 12.95 percent return were to be applied to rate refunds, with the remaining one-third retained by the Company. The Company's earnings in 2004, 2003, and 2002 were within the retail ROE range.

Under the 2001 Retail Rate Plan, the Company discontinued recording accelerated depreciation and amortization and began amortizing the accumulated balance equally over three years as a credit to expense beginning in 2002. Also, the 2001 Retail Rate Plan required the Company to recognize capacity and operating and maintenance costs related to new Georgia PSC-certified PPAs evenly in rates over a three-year period ended December 31, 2004.

Fuel Hedging Program

In 2003, the Georgia PSC approved an order allowing the Company to implement a natural gas and oil procurement and hedging program. This order allows the Company to use financial instruments to hedge price and commodity risk associated with these fuels. 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 the Company retaining 25 percent of the total net gains. In 2005, the Company had a total net gain of $64.1 million, of which the Company retained $16 million.

Fuel Cost Recovery

On May 17, 2005, the Georgia PSC approved the Company's request to increase customer fuel rates by approximately 9.5 percent to recover under recovered fuel costs of approximately $508 million existing as of May 31, 2005 over a four-year period that began June 1, 2005. Based on the order, a portion of the under recovered regulatory clause revenues was reclassified from current assets to deferred charges and other assets in the balance sheet. Under recovered fuel amounts for the periods subsequent to June 1, 2005 totaled $327.5 million through December 31, 2005. The Georgia PSC's order instructs that such amounts be reviewed semi-annually beginning February 2006. If the amount under or over recovered exceeds $50 million at the evaluation date, the Company would be required to file for a temporary fuel rate change. In addition, Savannah Electric's under recovered fuel costs totaled $77.7 million at December 31, 2005. In accordance with the Georgia PSC order, Savannah Electric was scheduled to file an additional request for a fuel cost recovery increase in January 2006. The Company has agreed with a Georgia PSC staff recommendation to forego the temporary fuel rate process, and Savannah Electric has postponed its scheduled filing. Instead, the Company and Savannah Electric will file a combined request in March 2006 to increase the Company's fuel cost recovery rate.

The case will seek approval of a fuel cost recovery rate based upon future fuel cost projections for the combined Company and Savannah Electric generating fleet as well as the under recovered fuel balances existing at June 30, 2006. The new fuel cost recovery rate would be billed beginning in July 2006 to all of the Company's customers, including the existing Savannah Electric customers. Under recovered amounts as of the date of the Merger will be paid by the appropriate customer groups.

In August 2005, the Georgia PSC initiated an investigation of Savannah Electric's fuel practices. In February 2006, an investigation of the Company's fuel

practices was initiated. The Company and Savannah Electric are responding to data requests and cooperating in the investigations. The final outcome of this matter cannot now be determined.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable cost and amounts billed in current regulated rates. Accordingly, any increase in the billing factor would have no significant effect on the Company's revenues or net income, but would increase annual cash flow.

Nuclear Performance Standards

Through December 2004, the Georgia PSC had adopted a three-year performance standard for the Company's nuclear generating units. The performance standard was 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. For the period 2002-2004, the Company's performance fell within the criteria prescribed by the Georgia PSC; there was no associated award or penalty. Effective January 1, 2005, the Georgia PSC discontinued the nuclear performance standard.

Plant McIntosh Construction Project

In December 2002 after a competitive bidding process, the Georgia PSC certified PPAs between Southern Power and the Company and Savannah Electric for capacity from Plant McIntosh Units 10 and 11, construction of which was completed in June 2005. In April 2003, Southern Power applied for FERC approval of these PPAs. In July 2003, the FERC accepted the PPAs to become effective June 1, 2005, subject to refund, and ordered that hearings be held. Intervenors opposed the FERC's acceptance of the PPAs, alleging that they did not meet the applicable standards for market-based rates between affiliates. To ensure the timely completion of the Plant McIntosh construction project and the availability of the units in the summer of 2005 for their retail customers, in May 2004, the Company and Savannah Electric requested the Georgia PSC to direct them to acquire the Plant McIntosh construction project. The Georgia PSC issued such an order and the transfer occurred on May 24, 2004 at a total cost of approximately $415 million, including approximately $14 million of transmission interconnection facilities. Subsequently, Southern Power filed a request to withdraw the PPAs and to terminate the ongoing FERC proceedings. In August 2004, the FERC issued a notice accepting the request to withdraw the PPAs and permitting such request to become effective by operation of law. However, the FERC made no determination on what additional steps may need to be taken with respect to testimony provided in the proceedings. See "FERC Matters – Intercompany Interchange Contract" herein for additional information.

In connection with the 2004 Retail Rate Plan, the Georgia PSC approved the transfer of the Plant McIntosh construction project at a total fair market value of approximately $385 million. This value reflected an approximate $16 million disallowance, of which $13 million was attributable to the Company, and reduced the Company's net income by approximately $8 million. The Georgia PSC also certified a total completion cost not to exceed $547 million for the project. In June 2005, Plant McIntosh Units 10 and 11 were placed into service at a total cost that did not exceed the certified amount. Under the 2004 Retail Rate Plan, the Plant McIntosh revenue requirements impact is being reflected in the Company's rates evenly over the three years ending 2007. See "Retail Regulatory Matters—Rate Plans" herein for additional information regarding the transfer of the Plant McIntosh construction project.

4. JOINT OWNERSHIP AGREEMENTS

The Company and an affiliate, Alabama Power, own equally all of the outstanding capital stock of SEGCO which owns electric generating units with a total rated capacity of 1,020 megawatts, as well as associated transmission facilities. The capacity of 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:

	2005	2004	2003
		(in millions)	
Energy	$54	$51	$55
Capacity	38	36	34
Total	$92	$87	$89

The Company 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 (MEAG), the city of Dalton, Georgia, Florida Power & Light Company, Jacksonville Electric Authority, and Gulf Power. Under these agreements, the Company has contracted to operate and maintain the plants as agent for the co-owners and 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 combustion- turbine common facilities and Plant McIntosh combined cycle units with Savannah Electric who operates the plants. The Company and Progress Energy Florida, Inc. jointly own a combustion turbine unit (Intercession City) operated by Progress Energy Florida, Inc.

At December 31, 2005, 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%	$3,311*	$1,809
Plant Hatch (nuclear)	50.1	935	492
Plant Wansley (coal)	53.5	395	172
Plant Scherer (coal)			
Units 1 and 2	8.4	115	56
Unit 3	75.0	562	270
Plant McIntosh CC (combined cycle)	83.9	436	7
Plant McIntosh Common Facilities (combustion-turbine)	75.0	27	5
Rocky Mountain (pumped storage)	25.4	169*	92
Intercession City (combustion-turbine)	33.3	12	2

*Investment includes write-offs

At December 31, 2005, the portion of total construction work in progress related to Plants Wansley, Scherer, and Rocky Mountain was $8.3 million, $0.5 million, and $0.1 million, respectively, primarily for environmental projects.

The Company's proportionate share of its plant operating expenses is included in the corresponding operating expenses in the statements of income.

5. INCOME TAXES

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

In 2004, in order to avoid the loss of certain federal income tax credits related to the production of synthetic fuel, Southern Company chose to defer certain

deductions otherwise available to the subsidiaries. The cash flow benefit associated with the utilization of the tax credits was allocated to the subsidiary that otherwise would have claimed the available deductions on a separate company basis without the deferral. This allocation concurrently reduced the tax benefit of the credits allocated to those subsidiaries that generated the credits. As the deferred expenses are deducted, the benefit of the tax credits will be repaid to the subsidiaries that generated the tax credits. The Company has recorded $10 million payable to these subsidiaries in Accumulated Deferred Income Taxes on the balance sheets at December 31, 2005.

The transfer of the Plant McIntosh construction project from Southern Power to the Company resulted in a deferred gain to Southern Power for federal income tax purposes. The Company will reimburse Southern Power for the remaining balance of the related deferred taxes of $5.3 million reflected in Southern Power's future taxable income. $3.7 million of this payable to Southern Power is included in Other Deferred Credits and $1.6 million is included in Affiliated Accounts Payable in the balance sheet at December 31, 2005.

The transfer of the Dahlberg, Wansley, and Franklin projects to Southern Power from the Company in 2001 and 2002 also resulted in a deferred gain for federal income tax purposes. Southern Power will reimburse the Company for the remaining balance of the related deferred taxes of $12.2 million reflected in the Company's future taxable income. $10.8 million of this receivable from Southern Power is included in Other Deferred Debits and $1.4 million is included in Affiliated Accounts Receivable in the balance sheet at December 31, 2005.

At December 31, 2005, tax-related regulatory assets were $501 million and tax-related regulatory liabilities were $159 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:

	2005	2004	2003
Total provision for income taxes:		(in millions)	
Federal:			
Current	**$173**	$116	$143
Deferred	**203**	221	181
	376	337	324
State:			
Current	**26**	12	24
Deferred	**29**	30	16
Deferred investment tax credits	**-**	-	2
Total	**$431**	$379	$366

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:

	2005	2004
	(in millions)	
Deferred tax liabilities:		
Accelerated depreciation	**$2,177**	$2,050
Property basis differences	**558**	577
Employee benefit obligations	**163**	149
Fuel clause under recovery	**305**	141
Premium on reacquired debt	**69**	72
Storm damage reserve	**13**	6
Other	**74**	81
Total	**3,359**	3,076
Deferred tax assets:		
Federal effect of state deferred taxes	**116**	106
Other property basis differences	**139**	147
Other deferred costs	**126**	94
Employee benefit obligations	**51**	55
Other comprehensive income	**23**	22
Unbilled revenue	**13**	11
Other	**33**	19
Total	**501**	454
Total deferred tax liabilities, net	**2,858**	2,622
Portion included in current (liabilities) assets, net	**(128)**	(66)
Accumulated deferred income taxes in the balance sheets	**$2,730**	$2,556

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 2005, $12 million in 2004, and $15 million in 2003. At December 31, 2005, all investment tax credits available to reduce federal income taxes payable had been utilized.

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

	2005	2004	2003
Federal statutory rate	35%	35%	35%
State income tax, net of federal deduction	3	3	3
Non-deductible book depreciation	1	1	1
Other	(1)	(2)	(2)
Effective income tax rate	38%	37%	37%

6. FINANCING

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

The Company has formed certain wholly owned trust subsidiaries for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the Company through the issuance of junior subordinated notes totaling $969 million, which constitute substantially all of the assets of the trusts and are reflected in the balance sheets as Long-Term Debt Payable to Affiliated Trusts. The Company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the respective trusts' payment obligations with respect to these securities. At December 31, 2005, preferred securities of $940 million were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for these trusts and the related securities.

Securities Due Within One Year

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

	2005	2004
	(in millions)	
Capital lease	$ 3	$ 2
Senior notes	150	450
Preferred stock	15	-
Total	$168	$452

Serial maturities through 2010 applicable to total long-term debt and preferred stock are as follows: $168 million in 2006; $303 million in 2007; $3 million in 2008; $278 million in 2009; and $4 million in 2010.

Pollution Control Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such 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, 2005 was $1.7 billion.

Senior Notes

The Company issued a total of $625 million of unsecured senior notes in 2005. The proceeds of these issues were used to redeem or repay at maturity long-term debt, to repay short-term indebtedness, and for other general corporate purposes. At December 31, 2005 and 2004, the Company had $2.6 billion and $2.4 billion of senior notes outstanding, respectively. These senior notes are subordinate to all secured debt of the Company.

Capital Leases

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, 2005 and 2004, the Company had a capitalized lease obligation for its corporate headquarters

building of $74 million and $77 million, respectively, with an interest rate of 8.1 percent. For ratemaking purposes, the Georgia PSC 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 Georgia PSC. See Note 1 under "Regulatory Assets and Liabilities."

Bank Credit Arrangements

At the beginning of 2006, the Company had credit arrangements with banks totaling $780 million, of which $778 million was unused. Of these facilities, $70 million expires at various times throughout 2006; $350 million expires in 2007, with the remaining $360 million expiring in 2010. The facilities that expire in 2006 provide the option of converting borrowings into a two-year term loan. The Company expects to renew its facilities, as needed, prior to expiration. The agreements contain stated borrowing rates. All the agreements require payment of commitment fees based on the unused portion 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. A fee is also paid to the agent bank.

The credit arrangements contain covenants that limit the level of indebtedness to capitalization to 65 percent, as defined in the arrangements. For purposes of these definitions, indebtedness excludes the long-term debt payable to affiliated trusts. In addition, the credit arrangements contain cross default provisions that would trigger an event of default if the Company defaulted on other indebtedness above a specified threshold. At December 31, 2005, the Company was in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowings.

The $778 million 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, 2005 was $106 million. In addition, the Company borrows under a commercial paper program and an extendible commercial note program. The amount of commercial paper outstanding at December 31, 2005 was $268 million. The amount of commercial paper outstanding at December 31, 2004 was $208 million. There were no outstanding extendible commercial notes at December 31, 2005. Commercial paper is included in notes payable on the balance sheets.

During 2005, the peak amount of short-term debt outstanding was $549 million and the average amount outstanding was $242 million. The average annual interest rate on short-term debt in 2005 was 3.20 percent.

Financial Instruments

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. See Note 3 under "Retail Regulatory Matters – Fuel Hedging Program" for information on the Company's fuel hedging program. The Company also enters into hedges of forward electricity sales. There was no material ineffectiveness recorded in earnings in 2005, 2004, and 2003.

At December 31, 2005, the fair value of derivative energy contracts was reflected in the financial statements as follows:

	Amounts
	(in thousands)
Regulatory liabilities, net	$26,643
Other comprehensive income	-
Net income	(81)
Total fair value	$26,562

The fair value gain or loss for hedges that are recoverable through the regulatory fuel clauses are recorded in regulatory assets and liabilities and are recognized in earnings at the same time the hedged items affect earnings. The Company has energy-related hedges in place up to and including 2008.

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

addition to interest rate swaps, the Company has also entered into certain options agreements that effectively cap its interest rate exposure in return for payment of a premium. In some cases, costless collars have been used that effectively establish a floor and a ceiling to interest rate expense.

At December 31, 2005, the Company had $1.0 billion notional amounts of interest derivatives accounted for as cash flow hedges outstanding with net fair value gains as follows:

Maturity	Weighted Average Fixed Rate Paid	Notional Amount	Fair Value Gain / (Loss)
		(in millions)	
2007	2.67%	$300	$ 2.4
2006-2007	2.09% -3.85%*	$400	$ 1.2
2037	4.58% -5.75%**	$300	$(1.1)

*Series of interest rate caps and collars (showing the lowest floor and highest cap) with variable rate based on one-month LIBOR
**Interest rate collar

The fair value gain or loss for cash flow hedges is recorded in other comprehensive income and is reclassified into earnings at the same time the hedged items affect earnings. In 2005, 2004, and 2003, the Company settled gains (losses) totaling $0.9 million, $(12.4) million, and $(11.3) million, respectively, upon termination of certain interest derivatives at the same time it issued debt. For the years 2005, 2004, and 2003, approximately $1.9 million, $3.9 million, and $3.4 million, respectively, of pre-tax losses were reclassified from other comprehensive income to interest expense. For 2006, pre-tax losses of approximately $0.5 million are expected to be reclassified from other comprehensive income to interest expense. The Company has gains/losses that are being amortized through 2017.

7. COMMITMENTS

Construction Program

The Company currently estimates property additions to be approximately $1.3 billion, $1.4 billion, and $1.3 billion in 2006, 2007, and 2008, respectively. These amounts include $44 million, $28 million, and $14 million in 2006, 2007, and 2008, respectively, for construction expenditures related to contractual purchase commitments for uranium and nuclear fuel conversion, enrichment, and fabrication services included under "Fuel Commitments" herein. 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, changes in FERC rules and transmission regulations, 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, 2005, significant purchase commitments were outstanding in connection with the construction program.

The Company completed construction of Plant McIntosh Units 10 and 11 in June 2005 and has no other generating plants currently under construction. Construction related to new transmission and distribution facilities and capital improvements to existing generation, transmission and distribution facilities, including those needed to meet environmental standards, is ongoing.

Long-Term Service Agreements

The Company and Savannah Electric have entered into a Long-Term Service Agreement (LTSA) with General Electric (GE) for the purpose of securing maintenance support for the combustion turbines at the Plant McIntosh combined cycle facility. In summary, the LTSA stipulates that GE will perform all planned inspections on the covered equipment, which includes the cost of all labor and materials. GE is also obligated to cover the costs of unplanned maintenance on the covered equipment subject to a limit specified in each contract.

In general, this LTSA is in effect through two major inspection cycles per unit. Scheduled payments to GE are made at various intervals based on actual operating hours of the respective units. Total payments to GE under this agreement are currently estimated at $186 million over the remaining term of the agreement, which may range up to 30 years. However, the LTSA contains various cancellation provisions at the option of the Company.

The Company has also entered into an LTSA with GE through 2014 for neutron monitoring system parts and electronics at Plant Hatch. Total remaining payments to GE under this agreement are currently estimated at $13.1 million. The contract contains

cancellation provisions at the option of the Company.

Payments made to GE prior to the performance of any work are recorded as a prepayment in the balance sheets. Work performed by GE is capitalized or charged to expense as appropriate net of any joint owner billings, based on the nature of the work.

Fuel Commitments

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement of fossil and nuclear fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Coal commitments include forward contract purchases for sulfur dioxide emission allowances. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery. Amounts included in the chart below represent estimates based on New York Mercantile Exchange future prices at December 31, 2005.

Total estimated minimum long-term obligations at December 31, 2005 were as follows:

	Commitments		
	Natural Gas	Coal	Nuclear Fuel
		(in millions)	
2006	$577	$1,579	$ 44
2007	325	1,313	28
2008	200	907	14
2009	257	422	11
2010	254	272	14
2011 and thereafter	2,047	40	64
Total	$3,660	$4,533	$175

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

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other Southern Company retail operating companies, Southern Power, and Southern Company Gas. Under these agreements, each of the retail operating companies, Southern Power, and Southern Company Gas may be jointly and severally liable. The creditworthiness of Southern Power and Southern Company Gas is currently inferior to the creditworthiness of the retail operating companies. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the retail 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 Company Gas as a contracting party under these agreements.

Purchased Power Commitments

The Company has commitments regarding a portion of a 5 percent interest in Plant Vogtle owned by 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 $54 million, $55 million, and $57 million in 2005, 2004, and 2003, respectively. The current projected Plant Vogtle capacity payments are:

	Capacity Payments
	(in millions)
2006	$ 53
2007	52
2008	54
2009	54
2010	54
2011 and thereafter	261
Total	$528

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 at the time of the disallowance was written off.

The Company has entered into other various long-term commitments for the purchase of electricity. Estimated total long-term obligations under these

commitments at December 31, 2005 were as follows:

	Commitments	
	Affiliated	Non-Affiliated
	(in millions)	
2006	$205	$85
2007	205	86
2008	205	87
2009	205	68
2010	112	66
2011 and thereafter	455	278
Total	$1,387	$670

Operating Leases

The Company has entered into various operating leases with various terms and expiration dates. Rental expenses related to these operating leases totaled $38 million for 2005, $38 million for 2004, and $36 million for 2003.

At December 31, 2005, estimated minimum lease payments for these noncancelable operating leases were as follows:

	Minimum Lease Payments		
	Rail Cars	Other	Total
		(in millions)	
2006	$ 17	$ 17	$ 34
2007	17	14	31
2008	16	11	27
2009	15	9	24
2010	14	6	20
2011 and thereafter	48	10	58
Total	$127	$67	$194

In addition to the rental commitments above, the Company has obligations upon expiration of certain rail car leases with respect to the residual value of the leased property. These leases expire in 2011 and the Company's maximum obligation is $68 million. 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 rail car lease obligations is shared with the joint owners of plants Scherer and Wansley. Rental expenses related to the rail car leases are fully recoverable through the fuel cost recovery clause as ordered by the Georgia PSC.

Guarantees

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. Alabama Power has also guaranteed $50 million in senior notes issued by SEGCO. The Company has agreed to reimburse Alabama Power for the pro rata portion of such obligations corresponding to the Company'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.

8. STOCK OPTION PLAN

Southern Company provides non-qualified stock options to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2005, 1,551 current and former employees of the Company participated in the stock option plan. The maximum number of shares of Southern Company common stock that may be issued under this plan may not exceed 55 million. The prices of options granted to date have been at the fair market value of the shares on the dates of grant. Options granted to date become exercisable pro rata over a maximum period of three years from the date of grant. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the stock option plan. Activity from 2003 to 2005 for the options granted

to the Company's employees under the stock option plan is summarized below:

	Shares Subject To Option	Average Option Price Per Share
Balance at December 31, 2002	7,178,597	$19.73
Options granted	1,455,517	27.98
Options canceled	(54,860)	25.47
Options exercised	(1,428,273)	16.92
Balance at December 31, 2003	7,150,981	21.92
Options granted	1,434,915	29.50
Options canceled	(6,371)	25.99
Options exercised	(1,450,309)	18.25
Balance at December 31, 2004	**7,129,216**	**24.19**
Options granted	**1,427,618**	**32.71**
Options canceled	**(12,910)**	**23.75**
Options exercised	**(1,838,033)**	**21.23**
Balance at December 31, 2005	**6,705,891**	**$26.82**

Options exercisable:	
At December 31, 2003	3,956,234
At December 31, 2004	4,304,091
At December 31, 2005	**3,989,722**

The following table summarizes information about options outstanding at December 31, 2005:

	Dollar Price Range of Options		
	13-21	21-28	28-35
Outstanding:			
Shares (in thousands)	991	2,922	2,794
Average remaining life (in years)	4.2	6.0	8.5
Average exercise price	$17.25	$25.94	$31.13
Exercisable:			
Shares (in thousands)	991	2,496	503
Average exercise price	$17.25	$25.59	$29.75

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act, the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the Company's nuclear power plants. The Act provides funds up to $10.76 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 $101 million per incident for each licensed reactor it operates but not more than an aggregate of $15 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 $203 million per incident but not more than an aggregate of $30 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 up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. The Company purchases the maximum limit allowed by NEIL 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 NEIL policies would be $48 million.

Following the terrorist attacks of September 2001, both ANI and NEIL confirmed that terrorist acts against commercial nuclear power plants would, subject to the normal policy limits, be covered under their insurance. Both companies, however, revised their policy terms on

a prospective basis to include an industry aggregate for all "non-certified" terrorist acts i.e., acts that are not certified acts of terrorism pursuant to the Terrorism Risk Insurance Act of 2002, which was renewed in 2005. The aggregate for all NEIL policies, which applies to non-certified property claims stemming from terrorism within a 12-month duration, is $3.24 billion plus any amounts available through reinsurance or indemnity from an outside source. The non-certified ANI nuclear liability cap is a $300 million shared industry aggregate during the normal ANI policy period.

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

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

10. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2005 and 2004 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred Stock
		(in millions)	
March 2005	**$1,370**	**$286**	**$142**
June 2005	**1,459**	**311**	**158**
September 2005	**2,219**	**626**	**355**
December 2005	**1,586**	**165**	**60**
March 2004	$1,199	$285	$144
June 2004	1,353	322	156
September 2004	1,582	486	287
December 2004	1,237	166	71

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

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SELECTED FINANCIAL AND OPERATING DATA 2001-2005

Georgia Power Company 2005 Annual Report

	2005	2004	2003	2002	2001
Operating Revenues (in thousands)	**$6,634,203**	$5,370,808	$4,913,507	$4,822,460	$4,965,794
Net Income after Dividends on Preferred Stock (in thousands)	**$714,999**	$658,001	$630,577	$617,629	$610,335
Cash Dividends on Common Stock (in thousands)	**$556,100**	$565,500	$565,800	$542,900	$527,300
Return on Average Common Equity (percent)	**14.15**	13.95	14.05	13.99	14.12
Total Assets (in thousands)	**$17,047,783**	$15,822,338	$14,850,754	$14,342,656	$14,447,973
Gross Property Additions (in thousands)	**$906,248**	$1,126,064	$742,810	$883,968	$1,389,751
Capitalization (in thousands):					
Common stock equity	**$5,214,535**	$4,890,561	$4,540,211	$4,434,447	$4,397,485
Preferred stock	**-**	14,609	14,569	14,569	14,569
Mandatorily redeemable preferred securities	**-**	-	940,000	940,000	789,250
Long-term debt payable to affiliated trusts	**969,073**	969,073	-	-	-
Long-term debt	**4,179,218**	3,709,852	3,762,333	3,109,619	2,961,726
Total (excluding amounts due within one year)	**$10,362,826**	$9,584,095	$9,257,113	$8,498,635	$8,163,030
Capitalization Ratios (percent):					
Common stock equity	**50.3**	51.0	49.0	52.2	53.9
Preferred stock	**-**	0.2	0.2	0.2	0.2
Mandatorily redeemable preferred securities	**-**	-	10.2	11.1	9.6
Long-term debt payable to affiliated trusts	**9.4**	10.1	-	-	-
Long-term debt	**40.3**	38.7	40.6	36.5	36.3
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Security Ratings:					
Preferred Stock -					
Moody's	**Baa1**	Baa1	Baa1	Baa1	Baa1
Standard and Poor's	**BBB+**	BBB+	BBB+	BBB+	BBB+
Fitch	**A**	A	A	A	A
Unsecured Long-Term Debt -					
Moody's	**A2**	A2	A2	A2	A2
Standard and Poor's	**A**	A	A	A	A
Fitch	**A+**	A+	A+	A+	A+
Customers (year-end):					
Residential	**1,832,520**	1,801,426	1,768,662	1,734,430	1,698,407
Commercial	**270,373**	265,543	258,276	250,993	244,674
Industrial	**8,206**	7,676	7,899	8,240	8,046
Other	**3,536**	3,482	3,434	3,328	3,239
Total	**2,114,635**	2,078,127	2,038,271	1,996,991	1,954,366
Employees (year-end)	**8,713**	8,731	8,714	8,837	9,048

N/A = Not Applicable.

SELECTED FINANCIAL AND OPERATING DATA 2001-2005 (continued)
Georgia Power Company 2005 Annual Report

	2005	2004	2003	2002	2001
Operating Revenues (in thousands):					
Residential	**$ 2,024,204**	$1,736,072	$1,583,082	$1,600,438	$1,507,031
Commercial	**2,206,252**	1,812,096	1,661,054	1,631,130	1,682,918
Industrial	**1,351,731**	1,172,936	1,012,267	1,004,288	1,106,420
Other	**60,625**	55,881	53,569	52,241	52,943
Total retail	**5,642,812**	4,776,985	4,309,972	4,288,097	4,349,312
Sales for resale - non-affiliates	**519,673**	246,545	259,376	270,678	366,085
Sales for resale - affiliates	**264,989**	166,245	174,855	98,323	99,411
Total revenues from sales of electricity	**6,427,474**	5,189,775	4,744,203	4,657,098	4,814,808
Other revenues	**206,729**	181,033	169,304	165,362	150,986
Total	**$6,634,203**	$5,370,808	$4,913,507	$4,822,460	$4,965,794
Kilowatt-Hour Sales (in thousands):					
Residential	**23,585,115**	22,930,372	21,778,582	22,144,559	20,119,080
Commercial	**29,768,402**	28,014,357	26,940,572	26,954,922	26,493,255
Industrial	**25,027,371**	26,357,271	25,703,421	25,739,785	25,349,477
Other	**601,330**	602,202	595,742	593,202	583,007
Total retail	**78,982,218**	77,904,202	75,018,317	75,432,468	72,544,819
Sales for resale - non-affiliates	**11,234,527**	5,969,983	8,835,804	8,069,375	8,110,096
Sales for resale - affiliates	**4,854,914**	4,782,873	5,844,196	3,962,559	3,133,485
Total	**95,071,659**	88,657,058	89,698,317	87,464,402	83,788,400
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**8.58**	7.57	7.27	7.23	7.49
Commercial	**7.41**	6.47	6.17	6.05	6.35
Industrial	**5.40**	4.45	3.94	3.90	4.36
Total retail	**7.14**	6.13	5.75	5.68	6.00
Sales for resale	**4.88**	3.84	2.96	3.07	4.14
Total sales	**6.76**	5.85	5.29	5.32	5.75
Residential Average Annual Kilowatt-Hour Use Per Customer	**12,974**	12,838	12,421	12,867	11,933
Residential Average Annual Revenue Per Customer	**$1,113**	$972	$903	$930	$894
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**15,097**	13,978	13,980	14,059	14,474
Maximum Peak-Hour Demand (megawatts):					
Winter	**13,501**	12,208	13,153	11,873	11,977
Summer	**15,953**	15,180	14,826	14,597	14,294
Annual Load Factor (percent)	**59.7**	61.5	61.0	60.4	61.7
Plant Availability (percent):					
Fossil-steam	**90.7**	90.3	87.6	80.9	88.5
Nuclear	**89.3**	94.8	94.2	88.8	94.4
Source of Energy Supply (percent):					
Coal	**60.8**	57.9	58.6	59.5	58.5
Nuclear	**15.1**	17.3	16.8	16.2	18.1
Hydro	**1.9**	1.5	2.1	0.9	1.1
Oil and gas	**2.9**	0.1	0.3	0.3	0.4
Purchased power -					
From non-affiliates	**5.7**	7.0	7.5	6.3	7.8
From affiliates	**13.6**	16.2	14.7	16.8	14.1
Total	**100.0**	100.0	100.0	100.0	100.0

DIRECTORS AND OFFICERS
Georgia Power Company 2005 Annual Report

Directors

Juanita Powell Baranco
Executive Vice President
Baranco Acura
(Resigned effective 2/21/2006)

Gus H. Bell, III – *Nominee*
Chairman, President and Chief Executive Officer
Hussey, Gay, Bell and DeYoung - A Bell Company

Robert L. Brown, Jr.
President and Chief Executive Officer
R. L. Brown & Associates, Inc.

Ronald D. Brown
President and Chief Executive Officer
Atlanta Life Financial Group

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

Michael D. Garrett
President and Chief Executive Officer
Georgia Power Company

David M. Ratcliffe
President and Chief Executive Officer
The Southern Company

D. Gary Thompson
Retired from
Wachovia Corporation

Richard W. Ussery
Retired from
Total System Services (TSYS)

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

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

Officers

Michael D. Garrett
President and Chief Executive Officer
Georgia Power Company

William C. Archer, III
Executive Vice President
External Affairs
(Retirement effective 3/19/2006)

Mickey A. Brown
Executive Vice President
Customer Service Organization

Cliff S. Thrasher
Executive Vice President, Chief Financial Officer
and Treasurer

Christopher C. Womack
Executive Vice President (Effective 3/11/2006)
External Affairs

Judy M. Anderson
Senior Vice President
Charitable Giving

Richard L. Holmes
Senior Vice President
Metro Region

E. Lamont Houston
Senior Vice President (Effective 1/14/2006)
Customer Service and Sales

Douglas E. Jones
Senior Vice President (Effective 3/11/2006)
Fossil and Hydro Generation

James H. Miller III
Senior Vice President and
General Counsel

Leslie R. Sibert
Vice President
Transmission

Gene L. Ussery
Vice President
Distribution

DIRECTORS AND OFFICERS

Georgia Power Company 2005 Annual Report

Michael K. Anderson
Vice President (Effective 1/14/2006)
Corporate Services

W. Craig Barrs
Vice President

Robert A. Bell
Vice President (Effective 2/15/2006)
Human Resources

Rebecca A. Blalock
Vice President
Information Technology

P. Mike Clanton
Vice President (Effective 1/14/2006)
Customer Service

Ann P. Daiss
Vice President, Comptroller and
Chief Accounting Officer (Effective 3/11/2006)

Walter Dukes
Region Vice President
East

A. Bryan Fletcher
Vice President
Supply Chain Management

J. Kevin Fletcher
Vice President
Community and Economic Development

Jeff G. Franklin
Region Vice President
Northwest

Oscar C. Harper IV
Vice President (Effective 2/11/2006)
Resource Planning and Nuclear Development

O. Ben Harris
Vice President
Land

W. Ron Hinson
Vice President, Comptroller and
Chief Accounting Officer (Resigned effective
3/11/2006)

Ed F. Holcombe
Vice President
Governmental and Regulatory Affairs

Charles H. Huling
Vice President
Environmental Affairs

Anne H. Kaiser
Vice President
Sales

Ellen N. Lindemann
Vice President (Resigned effective 2/1/2006)
Human Resources

Jacki W. Lowe
Region Vice President
West

Daniel M. Lowery
Corporate Secretary

Terri H. Lupo
Region Vice President
South

Frank J. McCloskey
Vice President
Diversity

Robert B. Morris
Assistant Comptroller and Assistant Secretary

James E. Sykes, Jr.
Region Vice President
Northeast

Mark K. Tate
Assistant Comptroller

Jeff L. Wallace
Vice President (Resigned effective 2/11/2006)
Planning and Utility Relations

Thomas J. Wicker
Region Vice President
Central

W. Tal Wright
Vice President
Corporate Communication

Wayne Boston
Assistant Secretary and
Assistant Treasurer

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

Profile
The Company produces and delivers electricity as an integrated utility to retail customers within the State of Georgia and to wholesale customers in the Southeast. The Company sells electricity to approximately 2.1 million customers within its service area of approximately 57,000 square miles. In 2005, retail energy sales accounted for 83 percent of the Company's total sales of 95.1 billion kilowatt-hours.

The Company is a wholly owned subsidiary of The Southern Company, which is the parent company of five retail operating companies and a wholesale generation subsidiary, as well as other direct and indirect subsidiaries. There is no established public trading market for the Company's common stock.

Trustee, Registrar and Interest Paying Agent
All series of Senior Notes and Trust Preferred Securities
JPMorgan Chase Bank, N.A.
Institutional Trust Services
4 New York Plaza, 15th Floor
New York, NY 10004

Number of Preferred Shareholders of record as of December 31, 2005, was 1,003.

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

Georgia Power Company
241 Ralph McGill Boulevard, N.E.
Atlanta, GA 30308-3374
(404) 506-6526

Auditors
Deloitte & Touche LLP
Suite 1500
191 Peachtree Street, N.E.
Atlanta, GA 30303

Legal Counsel
Troutman Sanders LLP
600 Peachtree Street, N.E.
Suite 5200
Atlanta, GA 30308

GEORGIA POWER
A SOUTHERN COMPANY

July 28, 2006

Docket Nos.: 50-321 50-424
50-366 50-425
72-36

NL-06-1486

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
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 2005.

2. A set of quarterly financial statements for the period ending June 30, 2006.

3. A one year projected Cash Flows Statement for period January 1, 2007, through December 31, 2007.

Should you have any questions in connection with our response, please contact me at (404) 506-7952 or Jan Miller at (404) 506-6690. This letter contains no NRC commitments.

Sincerely,

Robert A. Aubuchon

Enclosures

cc: Southern Nuclear Operating Company
Mr. J. T. Gasser, Executive Vice President
Mr. L. M. Stinson, Vice President, Plant Hatch
Mr. D. E. Grissette, Vice President, Plant Vogtle
Mr. D. R. Madison, General Manager – Plant Hatch
Mr. T. E. Tynan, General Manager – Plant Vogtle
RType: CHA02.004; CVC7000

U. S. Nuclear Regulatory Commission
Dr. W. D. Travers, Regional Administrator
Mr. C. Gratton, NRR Project Manager – Hatch
Mr. C. Gratton, NRR Project Manager – Vogtle
Mr. D. S. Simpkins, Senior Resident Inspector – Hatch
Mr. G. J. McCoy, Senior Resident Inspector – Vogtle

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2006	2005	2006	2005
OPERATING REVENUES:				
Retail sales	$1,420,762	$1,227,087	$2,687,718	$2,412,323
Sales for resale--				
Non-affiliates	132,557	126,000	265,921	238,852
Affiliates	85,674	54,743	120,616	80,374
Other revenues	59,745	51,358	111,932	98,069
Total operating revenues	1,698,738	1,459,188	3,186,187	2,829,618
OPERATING EXPENSES:				
Operation--				
Fuel	556,691	412,050	991,465	721,316
Purchased power--				
Non-affiliates	82,321	64,523	138,876	117,497
Affiliates	145,518	140,800	336,037	360,804
Other	226,256	223,471	444,976	425,550
Maintenance	119,876	123,575	239,176	240,225
Depreciation and amortization	117,590	124,999	235,447	248,099
Taxes other than income taxes	68,945	58,648	136,090	119,407
Total operating expenses	1,317,197	1,148,066	2,522,067	2,232,898
OPERATING INCOME	381,541	311,122	664,120	596,720
OTHER INCOME (EXPENSE):				
Allowance for equity funds used during construction	6,338	7,935	12,123	17,192
Interest income	199	31	515	502
Interest expense, net of amounts capitalized	(61,322)	(55,174)	(121,529)	(105,594)
Interest expense to affiliate trusts	(14,877)	(14,877)	(29,755)	(29,755)
Other income (expense), net	3,370	2,821	2,376	(21)
Total other income and (expense)	(66,292)	(59,264)	(136,270)	(117,676)
EARNINGS BEFORE INCOME TAXES	315,249	251,858	527,850	479,044
Income taxes	119,059	94,140	199,003	178,794
NET INCOME	196,190	157,718	328,847	300,250
DIVIDENDS ON PREFERRED STOCK	-	167	1,010	335
NET INCOME AFTER DIVIDENDS ON PREFERRED STOCK	$196,190	$157,551	$327,837	$299,915

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, 2006	At June 30, 2005
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$11,422	$9,294
Receivables --		
Customer accounts receivable	416,118	361,605
Unbilled revenues	176,184	168,392
Under recovered regulatory clause revenue	372,587	153,301
Other accounts and notes receivable	85,136	185,223
Affiliated companies	55,814	31,350
Accumulated provision for uncollectible accounts	(8,521)	(6,575)
Fossil fuel stock, at average cost	262,620	207,959
Materials and supplies, at average cost	352,866	286,446
Other	174,706	91,819
Total Current Assets	1,898,932	1,488,814
PROPERTY, PLANT AND EQUIPMENT:		
In service	19,957,393	19,327,416
Less accumulated provision for depreciation	7,775,166	7,392,744
	12,182,227	11,934,672
Nuclear fuel, at amortized cost	148,604	129,567
Construction work in progress	599,874	443,904
Total Property, Plant and Equipment	12,930,705	12,508,143
OTHER PROPERTY AND INVESTMENTS:		
Equity investments in unconsolidated subsidiaries	68,470	65,949
Nuclear decommissioning trusts	499,868	466,656
Other	70,800	64,472
Total Other Property and Investments	639,138	597,077
DEFERRED CHARGES AND OTHER ASSETS:		
Deferred charges related to income taxes	497,775	506,259
Prepaid pension costs	487,462	460,865
Unamortized debt issuance expense	84,515	88,638
Unamortized loss on reacquired debt	165,650	172,961
Deferred under recovered regulatory clause revenues	477,611	362,692
Other	255,106	170,698
Total Deferred Charges and Other Assets	1,968,119	1,762,113
TOTAL ASSETS	$17,436,894	$16,356,147

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

	At June 30, 2006	At June 30, 2005
LIABILITIES AND STOCKHOLDER'S EQUITY		
CURRENT LIABILITIES:		
Securities due within one year	$2,822	$402,603
Notes payable	657,559	379,902
Accounts payable --		
Affiliated companies	207,585	157,765
Other	292,313	248,786
Customer deposits	140,292	122,446
Taxes accrued		
Income taxes	313,302	183,985
Other	146,254	115,596
Interest accrued	74,533	78,595
Vacation pay accrued	45,692	44,179
Other	210,770	186,640
Total Current Liabilities	2,091,122	1,920,497
LONG-TERM DEBT	4,177,916	3,931,825
LONG-TERM DEBT PAYABLE TO AFFILIATED TRUSTS	969,073	969,073
DEFERRED CREDITS AND OTHER LIABILITIES:		
Accumulated deferred income taxes	2,693,006	2,598,783
Deferred credits related to income taxes	153,196	164,588
Accumulated deferred investment tax credits	281,581	293,872
Employee benefits provisions	379,656	346,916
Asset retirement obligations	647,003	520,298
Other	548,023	581,077
Total Deferred Credits and Other Liabilities	4,702,465	4,505,534
PREFERRED STOCK	-	14,609
COMMON STOCKHOLDER'S EQUITY:		
Common stock	344,250	344,250
Paid-in capital	2,880,563	2,589,121
Retained earnings	2,288,285	2,124,641
Accumulated other comprehensive income	(16,780)	(43,403)
Total Common Stockholder's Equity	5,496,318	5,014,609
TOTAL LIABILITIES AND STOCKHOLDER'S EQUITY	$17,436,894	$16,356,147

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

	FOR THE SIX MONTHS ENDED JUNE 2006	2005
OPERATING ACTIVITIES:		
Net income	$328,847	$300,250
Adjustments to reconcile net income to net cash provided by operating activities --		
Depreciation and amortization	276,048	292,447
Deferred income taxes and investment tax credits, net	13,433	89,724
Deferred expenses - affiliated	18,717	20,302
Allowance for funds used during construction	(12,123)	(17,192)
Pension, postretirement, and other employee benefits	(1,225)	5,318
Stock option expense	4,330	-
Other, net	8,729	(1,058)
Changes in certain current assets and liabilities --		
Receivables, net	(89,773)	(247,991)
Fossil fuel stock	(80,881)	(23,692)
Materials and supplies	(28,885)	(16,024)
Other current assets	49,999	14,055
Accounts payable	(128,890)	(59,236)
Taxes accrued	38,209	43,098
Other current liabilities	(76,833)	(42,595)
NET CASH PROVIDED FROM OPERATING ACTIVITIES	319,702	357,406
INVESTING ACTIVITIES:		
Gross property additions	(448,857)	(381,191)
Nuclear decommissioning trust fund purchases	(241,021)	(205,261)
Nuclear decommissioning trust fund sales	234,141	196,562
Cost of removal net of salvage	(10,658)	(10,359)
Other	(9,099)	(33,274)
NET CASH USED FOR INVESTING ACTIVITIES	(475,494)	(433,523)
FINANCING ACTIVITIES:		
Increase (decrease) in notes payable, net	389,817	171,669
Proceeds --		
Senior notes	-	375,000
Pollution control bonds	10,125	185,000
Capital contributions from parent company	232,328	100,000
Gross excess tax benefit of stock options	611	-
Redemptions --		
Pollution control bonds	(10,125)	(85,000)
Senior notes	(150,000)	(300,000)
Preferred stock	(14,569)	
Special deposits - redemption funds	-	(100,000)
Payment of preferred stock dividends	(12)	(211)
Payment of common stock dividends	(301,250)	(278,050)
Other	(347)	(16,494)
NET CASH PROVIDED FROM FINANCING ACTIVITIES	156,578	51,914
NET CHANGE IN CASH AND CASH EQUIVALENTS	786	(24,203)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	10,636	33,497
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$11,422	$9,294

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

GEORGIA POWER COMPANY
PROJECTED STATEMENT OF CASH FLOWS
2007 FORECAST
(Stated in Thousands of Dollars)

	2007 FORECAST
OPERATING ACTIVITIES	
Net income before preferred dividends	$831,346
Principal noncash items-	
Depreciation and amortization	622,394
Deferred income taxes, net	(26,943)
Allowance for equity funds used during construction	(71,263)
Pension, postretirement and other employee benefits	(16,032)
Other, net	230,590
Change in current assets & liabilities-	
Receivables	(36,755)
Inventories	10,331
Accounts payable	9,114
Other current assets and liabilities	95,611
NET CASH PROVIDED FROM OPERATING ACTIVITIES	1,648,393
INVESTING ACTIVITIES	
Gross property additions	(1,485,481)
Cost of removal, net of salvage	(34,695)
Allowance for equity funds used during construction	71,263
Other property and investments	(6,514)
NET CASH USED FOR INVESTING ACTIVITIES	(1,455,427)
FINANCING ACTIVITIES	
Increase in notes payable, net	(8,860)
Proceeds -	
Senior notes	675,000
Preferred stock	300,000
Capital contributions from parent company	126,619
Redemptions -	
Senior notes	(300,000)
Trust preferred securities	(300,000)
Capitalized leases	(2,550)
Stock Option Expense	12,399
Payment of preferred stock dividends	(3,370)
Payment of common stock dividends	(678,100)
Other	(13,702)
NET CASH USED FOR FINANCING ACTIVITIES	(192,564)
NET INC (DEC) IN CASH AND TEMPORARY CASH INVESTMENTS	$402
CASH AND TEMPORARY CASH INVESTMENTS AT BEG OF PERIOD	$15,750
CASH AND TEMPORARY CASH INVESTMENTS AT END OF PERIOD	$16,152

2005 *Annual Report*

GEORGIA POWER COMPANY

GEORGIA POWER

A SOUTHERN COMPANY

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Georgia Power Company 2005 Annual Report

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SUMMARY

	2005	2004	Percent Change
Financial Highlights *(in millions):*			
Operating revenues	**$6,634**	$5,371	23.5
Operating expenses	**$5,246**	$4,112	27.6
Net income after dividends on preferred stock	**$715**	$658	8.7
Operating Data:			
Kilowatt-hour sales *(in millions):*			
Retail	**78,982**	77,904	1.4
Sales for resale - non-affiliates	**11,235**	5,970	88.2
Sales for resale - affiliates	**4,855**	4,783	1.5
Total	**95,072**	88,657	7.2
Customers served at year-end *(in thousands)*	**2,115**	2,078	1.8
Peak-hour demand *(in megawatts)*	**15,953**	15,180	5.1
Capitalization Ratios *(percent):*			
Common stock equity	**50.3**	51.0	
Preferred stock	-	0.2	
Long-term debt payable to affiliated trusts	**9.4**	10.1	
Long-term debt	**40.3**	38.7	
Return on Average Common Equity *(percent)*	**14.15**	13.95	
Ratio of Earnings to Fixed Charges *(times)*	**4.92**	5.11	

LETTER TO INVESTORS

Georgia Power 2005 Annual Report

Georgia Power employees' extraordinary response after Hurricane Katrina and other storms hit the Gulf Coast last year is just one of the highlights in what was a remarkable year for the company.

Whether we're responding to storms in our own back yard or to the needs of fellow Southern Company employees and customers, it's extensive pre-planning and excellent execution that makes us so successful – it really is what we do best.

That's why we were honored when the Edison Electric Institute recognized us with its Emergency Assistance Award for the outstanding assistance we provided other utilities recovering last year from hurricanes Katrina, Rita and Wilma.

Our financial results mirror our operational success. With operating revenues of $6.6 billion, Georgia Power's 2005 earnings totaled $715 million, a $57 million, or 8.7 percent, increase from 2004. We earned a 14.15 percent total company return on average common equity during 2005. Georgia Power had net plant in service of $12.0 billion at the end of 2005, with total assets of $17.0 billion.

In 2005, we announced plans to merge one of our sister companies into Georgia Power; we made significant progress on the environmental front; and we overhauled our organizational structure to bring us even closer to our customers.

Late last year, the boards of directors of Southern Company, Savannah Electric and Georgia Power approved a plan to merge Savannah Electric into Georgia Power. This move should result in operational efficiencies and cost savings for Georgia Power.

Savannah Electric customers also are expected to benefit from Georgia Power's more diverse and cost-efficient generating fleet. We anticipate completing the merger by July 2006.

We continued our efforts last year to reduce the environmental impact of our operations by:

- Turning on selective catalytic reduction systems at plants Bowen, Hammond and Wansley. This is expected to reduce the company's emissions of nitrogen oxides and, therefore, its contribution to metro Atlanta's ozone from 15 percent to 6 percent.

- Filing applications for four more scrubbers – two for Plant Wansley and two additional scrubbers for Plant Bowen. Two scrubbers are already under construction at Plant Bowen. Not only will the scrubbers, which remove sulfur dioxide (SO_2) from power plant emissions, reduce SO_2 emissions on each of these generating units by as much as 95 percent, but they also will reduce emissions of fine particulates and mercury. This is important because the Environmental Protection Agency issued its first mercury rule last year requiring significant reductions in mercury emissions from power plants.

- Working closely with DeKalb County in metro Atlanta, which approved the development of a landfill gas generation plant and a 10-year contract to sell the energy to Georgia Power for our voluntary Green Energy program.

In the past 10 years, we have invested $1 billion in environmental controls, and we'll continue to invest in environmental improvement technologies. In fact, over the next five years, Georgia Power's additional environmental investment is expected to total at least $2.4 billion.

In 2005, we also implemented a new organizational structure that moves key company leaders closer to our customers, employees and the communities we serve. We now have officer positions in major cities around the state, including Athens, Augusta, Columbus, Macon, Rome, Valdosta and, following the merger, Savannah.

Our new structure allows us to enhance efficiencies and operate consistently around the state while providing multiple cross-company leadership development opportunities within Southern Company – a key priority as we work to further develop the diversity and strength of our management ranks.

We believe improving diversity in every facet of our business is, simply put, good for business. That's why last year, for example, we launched a Hispanic Resources Web site, a one-stop shop for information to assist Spanish-speaking customers.

After all our hard work, it's nice to be recognized for our success. *Profiles in Diversity Journal* named Georgia Power to its top-10 list of diversity innovation award winners. We also were one of the Fortune 500 companies recognized as the nation's "Best Workplaces for Commuters," in large part because of SmartRide, our company commuter program that has become more popular than ever because of rising fuel prices. *Site Selection* magazine also recognized us as one of the best company's in North America for economic development.

We're especially proud of our linemen, who really shined at the International Lineman's Rodeo last year in Kansas City, winning first place in the overall, overall apprentice, investor-owned utility and senior divisions, along with a handful of individual event awards.

Continued economic vitality in Georgia helped boost electricity sales and was a key contributor to our strong financial results last year. Businesses and individuals were drawn to the state, increasing the number of customers Georgia Power serves to 2.1 million in 2005, a 1.8 percent increase from the previous year. Our retail sales of electricity climbed 1.4 percent in 2005.

It's clear to me that the work our employees do day in and day out and their commitment to the company are what make us successful – they are our greatest asset.

The changes we made and initiatives we launched last year will help ensure that we continue doing what's best for our employees, customers and communities – that we live up to our motto of being a "Citizen Wherever We Serve" – as we work to meet the state's growing demand for energy.

Sincerely,

Michael D. Garrett
April 17, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Georgia Power Company:

We have audited the accompanying balance sheets and statements of capitalization of Georgia Power Company (the "Company") (a wholly owned subsidiary of Southern Company) as of December 31, 2005 and 2004, 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, 2005. 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 the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements (pages 25 to 57) present fairly, in all material respects, the financial position of Georgia Power Company at December 31, 2005 and 2004, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
February 27, 2006

OVERVIEW

Business Activities

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

Many factors affect the opportunities, challenges, and risks of the Company's primary business of selling electricity. These factors include the ability to maintain a stable regulatory environment, to achieve energy sales growth while containing costs, and to recover rising costs. These costs include those related to growing demand, increasingly stringent environmental standards, and fuel prices. In December 2004, the Company completed a major retail rate proceeding that is expected to provide earnings stability (2004 Retail Rate Plan). This regulatory action also enables the recovery of substantial capital investments to facilitate the continued reliability of the transmission and distribution network and continued environmental improvements at the generating plants. Appropriately balancing environmental expenditures with customer prices will continue to challenge the Company for the foreseeable future. The Company expects further rate proceedings in 2006 to address fuel cost recovery due to higher than expected fuel costs for coal and natural gas.

On December 13, 2005, the Company and Savannah Electric and Power Company (Savannah Electric) entered into a merger agreement, under which Savannah Electric will merge into the Company, with the Company continuing as the surviving corporation (the Merger). The Merger must be approved by Savannah Electric's preferred shareholders and is subject to receipt of certain regulatory approvals from the Federal Energy Regulatory Commission (FERC), the Georgia Public Service Commission (PSC), and the Federal Communications Commission. Pending regulatory approvals, the Merger is expected to be completed by July 2006. See FUTURE EARNINGS POTENTIAL – "Merger" and Note 3 to the financial statements under "Retail Regulatory Matters – Merger" for additional information.

Key Performance Indicators

In striving to maximize shareholder value while providing low-cost energy to more than two million customers, the Company continues to focus on several key indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income. The Company's financial success is directly tied to the satisfaction of its customers. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance, expected weather conditions, and expected capital expenditures. Net income is the primary component of the Company's contribution to Southern Company's earnings per share goal.

The Company's 2005 results compared to its targets for some of these indicators are reflected in the following chart.

Key Performance Indicator	2005 Target Performance	**2005 Actual Performance**
Customer Satisfaction	Top quartile in customer surveys	**Top quartile**
Peak Season EFOR	2.75% or less	**1.42%**
Net Income	$678 million	**$715 million**

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The strong financial performance achieved in 2005 reflects the focus that management places on these indicators, as well as the commitment shown by the employees in achieving or exceeding management's expectations.

Earnings

The Company's 2005 earnings totaled $715 million representing a $57 million (8.7 percent) increase over 2004. Operating income increased in 2005 due to higher base retail revenues resulting from the retail rate increase

effective January 1, 2005 and more favorable weather, as well as higher wholesale revenues resulting from new contracts effective January 1, 2005, partially offset by increased non-fuel operating expenses. The Company's 2004 earnings totaled $658 million representing a $27 million (4.3 percent) increase over 2003. Operating income increased in 2004 due to higher base retail revenues attributable to more favorable weather and customer growth during the year, partially offset by higher non-fuel operating expenses. In addition, lower depreciation and amortization expense resulting from a Georgia PSC three-year retail rate plan approved in 2001 (2001 Retail Rate Plan) significantly offset increased purchased power capacity expenses. The Company's 2003 earnings totaled $631 million, representing a $13 million (2.1 percent) increase over 2002 despite lower base retail revenues resulting from the extremely mild summer weather. Higher wholesale revenues and lower non-fuel operating expenses contributed to the 2003 increase.

RESULTS OF OPERATIONS

A condensed income statement for the Company is as follows:

	Amount	Increase (Decrease) From Prior Year		
	2005	**2005**	2004	2003
		(in millions)		
Operating revenues	**$6,634**	**$1,263**	$457	$ 92
Fuel	**1,831**	**598**	128	101
Purchased power	**1,170**	**194**	200	92
Other operation and maintenance	**1,481**	**81**	153	(78)
Depreciation and amortization	**504**	**229**	(74)	(54)
Taxes other than income taxes	**260**	**32**	15	11
Total operating expenses	**5,246**	**1,134**	422	72
Operating income	**1,388**	**129**	35	20
Total other income and (expense)	**(241)**	**(20)**	5	2
Income taxes	**431**	**52**	13	9
Net income	**716**	**57**	27	13
Dividends on preferred stock	**1**	**-**	-	-
Net income after dividends on preferred stock	**$ 715**	**$ 57**	$ 27	$ 13

Revenues

Operating revenues in 2005, 2004, and 2003 and the percent of change from the prior year are as follows:

	Amount		
	2005	2004	2003
		(in millions)	
Retail – prior year	**$4,777**	$4,310	$4,288
Change in -			
Base rates	**195**	-	-
Sales growth	**135**	151	30
Weather	**21**	32	(66)
Fuel cost recovery and other	**515**	284	58
Retail – current year	**$5,643**	4,777	4,310
Sales for resale -			
Non-affiliates	**519**	247	260
Affiliates	**265**	166	175
Total sales for resale	**784**	413	435
Other operating revenues	**207**	181	169
Total operating revenues	**$6,634**	$5,371	$4,914
Percent change	**23.5%**	9.3%	1.9%

Retail base revenues of $3.6 billion in 2005 increased by $351 million (10.9 percent) from 2004 primarily due to the retail rate increase effective January 1, 2005, sustained economic strength, customer growth, more favorable weather, and generally higher prices to large business customers. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information. Retail base revenues of $3.2 billion in 2004 increased by $183 million (6.0 percent) from 2003 primarily due to an improved economy, customer growth, generally higher prices to the Company's large business customers, and more favorable weather. Retail base revenues of $3 billion in 2003 decreased by $36 million (1.2 percent) from 2002 primarily due to extremely mild summer temperatures and the sluggish economy.

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. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information.

Wholesale revenues from sales to non-affiliated utilities were:

	2005	2004	2003
		(in millions)	
Unit power sales --			
Capacity	$ 33	$ 31	$ 34
Energy	31	33	31
Other power sales --			
Capacity and other	155	75	93
Energy	300	108	102
Total	$519	$247	$260

Revenues from unit power sales contracts remained relatively constant in 2005 and 2004. Revenues from unit power sales contracts decreased slightly in 2003 due to decreased energy sales. Revenues from other non-affiliated sales increased $272 million (148.6 percent) in 2005 and decreased $12 million (6.2 percent) and $8 million (3.9 percent) in 2004 and 2003, respectively. The increase in 2005 is due to new contracts with thirty electric membership corporation customers that went into effect in January 2005 which increased the demand for energy. The capacity component of these transactions increased $73.2 million in 2005 over 2004.

Revenues from sales to affiliated companies within the Southern Company electric system, as well as purchases of energy, will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliated sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the FERC. In 2005, kilowatt-hour (KWH) energy sales to affiliates increased 1.5 percent due to higher demand, while the increase in associated revenues was 59.4 percent due to higher fuel prices. In 2004, KWH energy sales to affiliates decreased 18.2 percent due to lower demand. However, the decline in associated revenues was only 4.9 percent due to higher fuel prices. In 2003, KWH energy sales to affiliates increased 47.5 percent due to the combination of increased demand by Southern Power to meet contractual obligations and the availability of power due to milder-than-normal weather in the Company's service territory. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost.

Other operating revenues increased $25.7 million (14.2 percent) in 2005 from 2004 primarily due to higher transmission revenues of $16 million related to work performed for the other owners of the integrated transmission system in the State of Georgia and higher revenues under the open access tariff agreement, higher outdoor lighting revenues of $5.4 million, and higher customer fees that went into effect in January 2005 of $5.9 million. Other operating revenues increased $11.7 million (6.9 percent) in 2004 over 2003 primarily due to higher revenues from outdoor lighting of $4.2 million and pole attachment rentals of $4.9 million and higher gains on sales of emission allowances of $2 million. Other operating revenues increased $4 million (2.4 percent) in 2003 from the prior year primarily due to an increase in the open access transmission tariff rate, which increased revenues $7 million, and higher revenues from increased customer demand for outdoor lighting services of $4 million, partially offset by lower revenues from the rental of electric property of $4 million.

Energy Sales

KWH sales for 2005 and the percent change by year were as follows:

	KWH	Percent Change		
	2005	2005	2004	2003
	(in billions)			
Residential	23.6	2.9%	5.3%	(1.7)%
Commercial	29.8	6.3	4.0	(0.1)
Industrial	25.0	(5.0)	2.5	(0.1)
Other	0.6	(0.1)	1.1	0.4
Total retail	79.0	1.4	3.8	(0.5)
Sales for resale -				
Non-affiliates	11.2	88.2	(32.5)	9.5
Affiliates	4.9	1.5	(18.2)	47.5
Total sales for resale	16.1	49.6	(26.8)	22.0
Total sales	95.1	7.2	(1.2)	2.6

Residential KWH sales increased 2.9 percent in 2005 over 2004 due to more favorable weather, customer growth of 1.7 percent, and a 1.1 percent increase in the average energy consumption per customer. Commercial KWH sales increased 6.3 percent due to more favorable weather, sustained economic strength, customer growth of 1.8 percent, and a reclassification of customers from industrial to commercial to be consistent with the rate structure approved by the Georgia PSC when compared

to 2004. Industrial sales decreased 5.0 percent primarily due to this reclassification of customers.

Residential KWH sales increased 5.3 percent in 2004 from 2003 due to more favorable weather and a 1.9 percent increase in residential customers. Commercial KWH sales increased 4.0 percent in 2004 due to an improved economy and a 2.8 percent increase in commercial customers. Industrial sales increased 2.5 percent in 2004 due to the improved economy.

Residential KWH sales decreased 1.7 percent in 2003 from 2002 due to the effect of the milder summer weather, despite the 2.0 percent increase in residential customers. Commercial KWH sales in 2003 declined slightly due to the milder summer weather, while industrial KWH sales declined slightly due to the sluggish economy. Average retail sales growth assuming normal weather is expected to be 2.1 percent from 2006 to 2010.

Fuel and Purchased Power 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 generating units. The amount and sources of generation, the average cost of fuel per net KWH generated, and the average cost of purchased power per net KWH were as follows:

	2005	2004	2003
Total generation (billions of KWH)	**80.5**	71.5	73.1
Sources of generation (percent) --			
Coal	**75.3**	75.4	75.4
Nuclear	**18.6**	22.5	21.6
Hydro	**2.4**	2.0	2.7
Oil and gas	**3.7**	0.1	0.3
Average cost of fuel per net KWH generated (cents) --	**2.04**	1.55	1.46
Average cost of purchased power per net KWH (cents) --	**7.25**	5.17	4.03

Fuel expense increased 48.5 percent in 2005 from the prior year primarily due to an increase in the average cost of fuel, particularly natural gas, and a 12.3 percent increase in generation to meet higher demand. Fuel expense increased 11.6 percent in 2004 over 2003 primarily due to an increase in the average cost of coal and natural gas. Fuel expense increased 10.1 percent in 2003 over 2002 due to an increase in generation of 3.9 percent because of higher wholesale energy demands and a 2.8 percent higher average cost of fuel due to the higher prices of coal and natural gas in 2003.

Purchased power expense increased $194 million (19.9 percent) in 2005, $200 million (25.9 percent) in 2004, and $92 million (13.3 percent) in 2003. These increases are primarily the result of new purchased power agreements (PPAs) between the Company and Southern Power that went into effect in each of 2004, 2003, and 2002. Additional capacity expenses associated with these PPAs were $30 million, $65 million, and $75 million in 2005, 2004, and 2003, respectively. The increases in purchased power expenses also reflect the impact of the significant increases in fuel costs discussed previously.

A significant upward trend in the cost of coal and natural gas has emerged since 2003, and volatility in these markets is expected to continue. Increased coal prices have been influenced by a worldwide increase in demand as a result of rapid economic growth in China as well as by increases in mining costs. Higher natural gas prices in the United States are the result of increased demand and slightly lower gas supplies despite increased drilling activity. Natural gas supply interruptions, such as those caused by the 2005 and 2004 hurricanes, result in an immediate market response; however, the long-term impact of this price volatility may be reduced by imports of natural gas and liquefied natural gas. Fuel expenses generally do not affect net income, since they are offset by fuel revenues under the Company's fuel cost recovery provisions.

Other Operating Expenses

In 2005, other operations and maintenance expenses increased $81 million (5.8 percent). Maintenance for generating plant and transmission and distribution increased $23.5 million and $13.9 million, respectively, as a result of scheduled outages and, to a lesser extent, certain flexible projects planned for other periods. Increased employee benefit expense of $18.4 million related to pension and medical benefits and higher property insurance costs of $5.3 million resulting from storm damage also contributed to the increase. Customer

assistance expense and uncollectible account expense also increased an additional $9.3 million in 2005 over 2004, primarily as a result of promotional expenses related to an energy efficiency program and an increased number of customer bankruptcies, respectively. In 2004, other operations and maintenance expenses increased $153 million (12.3 percent) due to the timing of generating plant maintenance of $39 million and transmission and distribution maintenance of $39 million. Increased employee benefit expense of $30 million related to pension and medical benefits and higher workers compensation expense of $8 million also contributed to the increase. In 2003, other operations and maintenance expenses decreased $78 million (5.9 percent) due to the timing of generating plant maintenance of $46 million and transmission and distribution maintenance of $8 million and lower severance costs of $8 million.

Depreciation and amortization increased $229 million (83 percent) in 2005 over 2004 primarily due to the expiration at the end of 2004 of certain provisions of the Company's 2001 Retail Rate Plan. In accordance with the 2001 Retail Rate Plan, the Company amortized an accelerated cost recovery liability as a credit to amortization expense and recognized new Georgia PSC-certified purchased power costs in rates evenly over the three years ended December 31, 2004. This treatment resulted in a credit to amortization expense of $187.1 million in 2004 and a total decrease in depreciation and amortization of $74 million and $54 million in 2004 and 2003, respectively. See Note 3 to the financial statements under "Retail Regulatory Matters -- Rate Plans" for additional information.

Taxes other than income taxes increased $32 million (14.1 percent) primarily due to higher municipal gross receipts taxes of $18.1 million resulting from increased operating revenues and higher property taxes of $14.0 million. Taxes other than income taxes increased $15 million (7.0 percent) in 2004 due to higher municipal gross receipts taxes associated with increased operating revenues. Taxes other than income taxes increased $11 million (5.4 percent) in 2003 due mainly to a favorable true-up of state property tax valuations in 2002.

Other Income and (Expense)

Allowance for equity funds used during construction remained relatively constant in 2005 and increased $15.9 million in 2004, primarily due to the construction of the McIntosh combined cycle Units 10 and 11 which were placed in service in June 2005.

Interest income remained relatively constant in 2005. Interest income decreased $9 million in 2004 and increased $12 million in 2003 when compared to the prior year primarily due to interest on a favorable income tax settlement of $14.5 million in 2003.

Interest expense increased $38.8 million (21.3 percent) in 2005 from 2004 primarily due to the issuance of additional senior notes in 2005 and generally higher interest rates on variable rate debt and commercial paper. Interest expense remained relatively constant in 2004. Interest expense increased in 2003 primarily due to an increase in senior notes outstanding that was partially offset by a reduction in short-term debt outstanding. The Company refinanced or retired $635 million, $400 million, and $665 million of securities in 2005, 2004, and 2003, respectively. Interest capitalized increased in 2005 and 2004 due to the Plant McIntosh construction referenced above and decreased in 2003 due to the transfer of a project to Southern Power in 2002.

Other income and (expense), net increased $17.1 million in 2005 from 2004 primarily due to $14.2 million of additional gas hedge gains. Other income and (expense), net decreased in 2004 primarily due to the $13 million disallowance of Plant McIntosh construction costs in December 2004, partially offset by a $7.5 million decrease in donations and $3.4 million in increased income from a customer pricing program. See Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Hedging Program" and "Plant McIntosh Construction Project" for additional information.

Effects of Inflation

The Company is subject to rate regulation that is based on the recovery of historical costs. In addition, the income tax laws are based on historical costs. Therefore, inflation creates an economic loss because the Company is recovering its costs of investments in dollars that have less purchasing power. While the inflation rate has been relatively low in recent years, it continues to have an adverse effect on the Company because of the large investment in utility plant with long economic lives. Conventional accounting for historical cost does not recognize this economic loss nor the partially offsetting gain that arises through financing facilities with fixed-

money obligations such as long-term debt, preferred stock, and preferred securities. Any recognition of inflation by regulatory authorities is reflected in the rate of return allowed in the Company's approved electric rates.

FUTURE EARNINGS POTENTIAL

General

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

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability of the Company to maintain a stable regulatory environment that continues to allow for the recovery of all prudently incurred costs. Future earnings in the near term will depend, in part, upon growth in energy sales, which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth in the Company's service area.

Environmental Matters

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S District Court for the Northern District of Georgia against the Company and Alabama Power, alleging that the Company and Alabama Power had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws with respect to certain coal-fired generating facilities. Through subsequent amendments and other legal proceedings, the EPA added Savannah Electric as a defendant to the original action and filed a separate action against Alabama Power after it was dismissed from the original action. In these lawsuits, the EPA alleges that NSR violations occurred at eight coal-fired generating facilities, including the Company's Plants Bowen and Scherer. The civil action requests penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. On June 3, 2005, the U.S. District for the Northern District of Alabama issued a decision in favor of Alabama Power on two primary legal issues in the case; however, the decision does not resolve the case, nor does it address other legal issues associated with the EPA's allegations. In accordance with a separate court order, Alabama Power and the EPA are currently participating in mediation with respect to the EPA's claims. The action against the Company and Savannah Electric has been administratively closed since the spring of 2001, and none of the parties has sought to reopen the case. See Note 3 to the financial statements under "Environmental Matters - New Source Review Actions."

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $32,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in this matter could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

In December 2002 and October 2003, the EPA issued final revisions to its NSR regulations under the Clean Air Act. A coalition of states and environmental organizations filed petitions for review of these regulations. On June 24, 2005, the U.S. Court of Appeals for the District of Columbia Circuit upheld, in part, the EPA's December 2002 revisions to its NSR regulations, which included changes to the regulatory exclusions and

methods of calculating emissions increases. However, the court vacated portions of those revisions, including those addressing the exclusion of certain pollution control projects. The October 2003 revisions, which clarified the scope of the existing Routine Maintenance, Repair and Replacement exclusion, have been stayed by the Court of Appeals pending its review of the rules. On October 20, 2005, the EPA also published a proposed rule clarifying the test for determining when an emissions increase subject to the NSR requirements has occurred. The impact of these revisions and proposed rules will depend on adoption of the final rules by the EPA and the State of Georgia's implementation of such rules, as well as the outcome of any additional legal challenges, and, therefore, cannot be determined at this time.

Carbon Dioxide Litigation

In July 2004, attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed a complaint in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. A nearly identical complaint was filed by three environmental groups in the same court. The complaints allege that the companies' emissions of carbon dioxide, a greenhouse gas, contribute to global warming, which the plaintiffs assert is a public nuisance. Under common law public and private nuisance theories, the plaintiffs seek a judicial order (1) holding each defendant jointly and severally liable for creating, contributing to, and/or maintaining global warming and (2) requiring each of the defendants to cap its emissions of carbon dioxide and then reduce those emissions by a specified percentage each year for at least a decade. Plaintiffs have not, however, requested that damages be awarded in connection with their claims. Southern Company believes these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2005, the U.S. District Court for the Southern District of New York granted Southern Company's and the other defendants' motions to dismiss these cases. The plaintiffs filed an appeal to the U.S. Court of Appeals for the Second Circuit on October 19, 2005. The ultimate outcome of these matters cannot be determined at this time.

Plant Wansley Environmental Litigation

In December 2002, the Sierra Club, Physicians for Social Responsibility, Georgia Forestwatch, and one individual filed a civil suit in the U.S. District Court for the Northern District of Georgia against the Company for alleged violations of the Clean Air Act at four of the units at Plant Wansley. 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. The liability phase of the case has concluded with the court ruling in favor of the Company in part and the plaintiffs in part. In March 2005, the U.S. Court of Appeals for the Eleventh Circuit accepted the Company's petition for review of the district court's order, and oral arguments were held on January 24, 2006. The district court case has been administratively closed pending that appeal. If necessary, the district court will hold a separate trial which will address civil penalties and possible injunctive relief requested by the plaintiffs. The ultimate outcome of this matter cannot currently be determined; however, an adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require the payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

Environmental Statutes and Regulations

General

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. Applicable statutes 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 these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2005, the Company had invested approximately $1.2 billion in

capital projects to comply with these requirements, with annual costs of $117.4 million, $47.4 million, and $105.7 million for 2005, 2004, and 2003, respectively. Over the next decade, the Company expects that capital expenditures could exceed an additional $3.3 billion to assure compliance with existing and new regulations, including $410 million, $674.6 million, and $515.8 million for 2006, 2007, and 2008, respectively. Because the Company's compliance strategy is impacted by changes to existing environmental laws and regulations, the cost, availability, and existing inventory of emission allowances, and the Company's fuel mix, the ultimate outcome cannot be determined at this time. Environmental costs that are known and estimable at this time are included in capital expenditures discussed under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein.

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

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Through 2005, the Company had spent approximately $787.9 million in reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions and in monitoring emissions pursuant to the Clean Air Act. Additional controls have been announced and are currently being installed at several plants to further reduce SO_2 and NO_x emissions, maintain compliance with existing regulations, and to meet new requirements.

Approximately $699.8 million of these expenditures are related to reducing NO_x emissions pursuant to state and federal requirements in connection with the EPA's one-hour ozone standard and the 1998 regional NO_x reduction rules. Although the State of Georgia was originally included in the states subject to the regional NO_x rules, the EPA, in August 2005, stayed compliance with these requirements and initiated rulemakings to address issues raised in a petition for reconsideration filed by a coalition of Georgia industries. The impact of the 1998 regional NO_x reduction rules for Georgia will depend on the outcome of the petition for reconsideration and/or any subsequent development and approval of the State of Georgia's state implementation plan.

In 2005, the EPA revoked the one-hour ozone standard and published the final set of rules for implementation of the new, more stringent eight-hour ozone standard. Areas within the Company's service area that have been designated as nonattainment under the eight-hour ozone standard include Macon (Georgia) and a 20-county area within metropolitan Atlanta. State implementation plans, including new emission control regulations necessary to bring those areas into attainment are required for most areas by June 2007. These state implementation plans could require further reductions in NO_x emissions from power plants.

During 2005, the EPA's fine particulate matter "nonattainment" designations became effective for several areas within the Company's service area in Georgia, and the EPA proposed a rule for the implementation of the fine particulate matter standard. The EPA plans to finalize the proposed implementation rule in 2006. State plans for addressing the nonattainment designations are required by April 2008 and could require further reductions in SO_2 and NO_x emissions from power plants. The EPA has also published proposed revisions to lower the level of particulate matter currently allowed.

The EPA issued the final Clean Air Interstate Rule on March 10, 2005. This cap-and-trade rule addresses power plant SO_2 and NO_x emissions that were found to contribute to nonattainment of the eight-hour ozone and fine particulate matter standards in downwind states. Twenty-eight eastern states, including the State of Georgia, are subject to the requirements of the rule. The rule calls for additional reductions of NO_x and/or SO_2 to be achieved in two phases, 2009/2010 and 2015. These reductions will be accomplished by the installation of additional emission controls at the Company's coal-fired facilities or by the purchase of emission allowances from a cap-and-trade program.

The Clean Air Visibility Rule (formerly called the Regional Haze Rule) was finalized on July 6, 2005. The goal of this rule is to restore natural visibility conditions in certain areas (primarily national parks

and wilderness areas) by 2064. The rule involves the application of Best Available Retrofit Technology (BART) requirements and a review each decade, beginning in 2018, of progress toward the goal. BART requires that sources that contribute to visibility impairment implement additional emission reductions, if necessary, to make progress toward remedying current visibility concerns. For power plants, the Clean Air Visibility Rule allows states to determine that the Clean Air Interstate Rule satisfies BART requirements for SO_2 and NO_x. However, additional requirements could be imposed. By December 17, 2007, states must submit implementation plans that contain emission reduction strategies for implementing BART requirements and for achieving sufficient and reasonable progress toward the goal.

On March 15, 2005, the EPA announced the final Clean Air Mercury Rule, a cap-and-trade program for the reduction of mercury emissions from coal-fired power plants. The rule sets caps on mercury emissions to be implemented in two phases, 2010 and 2018, and provides for an emission allowance trading market. The Company anticipates that emission controls installed to achieve compliance with the Clean Air Interstate Rule and the eight-hour ozone and fine-particulate standards will also result in mercury emission reductions. However, the long-term capability of emission control equipment to reduce mercury emissions is still being evaluated, and the installation of additional control technologies may be required.

The impacts of the eight-hour ozone standard, the fine particulate matter nonattainment designations, the Clean Air Interstate Rule, the Clean Air Visibility Rule, and the Clear Air Mercury Rule on the Company, will depend on the development and implementation of rules at the state level. States implementing the Clean Air Mercury Rule and the Clear Air Interstate Rule, in particular, have the option not to participate in the national cap-and-trade programs and could require reductions greater than those mandated by the federal rules. Such impacts will also depend on resolution of pending legal challenges to the Clean Air Interstate Rule, the Clean Air Mercury Rule and a related petition from the State of North Carolina under section 126 of the Clean Air Act, also related to the interstate transport of air pollutants. Therefore, the full impacts of these regulations on the Company cannot be determined at this time. The Company has developed and continually updates a comprehensive environmental compliance strategy to comply with the continuing and new environmental requirements discussed above. As part of this strategy, the Company plans to install additional SO_2, NO_x, and mercury emission controls within the next several years to assure continued compliance with applicable air quality requirements.

Water Quality

In July 2004, the EPA published final rules under the Clean Water Act for the purpose of reducing impingement and entrainment of fish and fish larvae at power plants' cooling water intake structures. The new rules require baseline biological information and, perhaps, installation of fish protection technology near some intake structures at existing power plants.

The Company is installing cooling towers at additional facilities under the Clean Water Act to cool water prior to discharge. Near Atlanta, a cooling tower for one plant was completed in 2004 and two others are scheduled for completion in 2008. The total estimated cost of these projects is $173 million, with $85 million remaining to be spent. The Company is also conducting a study of the aquatic environment at another facility to determine if further thermal controls are necessary at that plant.

The full impact of these new rules will depend on the results of studies and analyses performed as part of the rules' implementation and the actual requirements established by the State of Georgia, and therefore, cannot be determined at this time

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and release 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 and monitor known sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Remediation" for additional information.

Under Georgia PSC ratemaking provisions, $22 million has been deferred in a regulatory liability account related to certain environmental insurance settlements. Under the 2004 Retail Rate Plan, this regulatory liability is being amortized as a credit to expense over a three-year period that began January 1, 2005. However, the Georgia PSC also approved an annual environmental accrual of $5.4 million. Environmental remediation expenditures are being charged against the resulting reserve as they are incurred. The annual accrual amount will be reviewed and adjusted in future regulatory proceedings.

Global Climate Issues

Domestic efforts to limit greenhouse gas emissions have been spurred by international discussions surrounding the Framework Convention on Climate Change, and specifically the Kyoto Protocol -- which proposes constraints on the emissions of greenhouse gases for a group of industrialized countries. The Bush Administration has not supported U.S. ratification of the Kyoto Protocol or other mandatory carbon dioxide reduction legislation; however, in 2002, it did announce a goal to reduce the greenhouse gas intensity of the U.S. – the ratio of greenhouse gas emissions to the value of U.S. economic output -- by 18 percent by 2012. A year later, the Department of Energy (DOE) announced the Climate VISION program to support this goal. Energy-intensive industries, including electricity generation, are the initial focus of this program. Southern Company is involved in the development of a voluntary electric utility sector climate change initiative in partnership with the government. In a memorandum of understanding signed in December 2004 with the DOE under Climate VISION, the utility sector pledged to reduce its greenhouse gas emissions rate by 3 percent to 5 percent by 2010-2012. The Company is continuing to evaluate future energy and emissions profiles relative to the Climate VISION program and is analyzing voluntary programs to support the industry initiative.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates at market-based prices. The Company also has FERC authority to make short-term opportunity sales at market rates. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in that proceeding. In February 2005, Southern Company submitted responsive information. In February 2006, the FERC suspended the proceeding. Any new market-based rate transactions in its retail service territory entered into after February 27, 2005 are subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. The impact of such sales through December 31, 2005 is not expected to exceed $4.9 million. The refund period covers 15 months. In the event that the FERC's default mitigation measures for entities that are found to have market power are ultimately applied, the Company may be required to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates. The final outcome of this matter will depend on the form in which the final methodology for assessing generation market power and mitigation rules may be ultimately adopted and cannot be determined at this time.

In addition, in May 2005, the FERC started an investigation to determine whether Southern Company satisfies the other three parts of the FERC's market-based rate analysis: transmission market power, barriers to entry, and affiliate abuse or reciprocal dealing. The FERC established a new refund period related to this expanded investigation. Any and all new market-based rate transactions both inside and outside Southern Company's retail service territory involving any Southern Company subsidiary, including the Company, will be subject to refund to the extent the FERC orders lower rates as a result of this new investigation, with the 15-month refund period beginning July 19, 2005. The impact of such sales through December 31, 2005 is not expected to exceed $10.9 million, of which $3.2 million relates to sales inside the retail service territory as discussed above. The FERC also directed that this expanded proceeding be held in abeyance pending the outcome of the proceeding on the IIC discussed below.

The Company believes that there is no meritorious basis for this proceeding and is vigorously defending itself in this matter. However, the final outcome of this

matter, including any remedies to be applied in the event of an adverse ruling in this proceeding, cannot now be determined.

Intercompany Interchange Contract

The Company's generation fleet in its retail service territory is operated under the IIC, as approved by the FERC. In May 2005, the FERC also initiated a new proceeding to examine (1) the provisions of the IIC among Alabama Power, the Company, Gulf Power, Mississippi Power, Savannah Electric, Southern Power, and Southern Company Services, Inc., as agent, under the terms of which the power pool of Southern Company is operated, and, in particular, the propriety of the continued inclusion of Southern Power as a party to the IIC, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining Southern Power as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of Southern Power, the FERC authorized Southern Power's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct. The FERC order directs that the administrative law judge who presided over the McIntosh PPA proceeding discussed herein under "PSC Matters – Plant McIntosh Construction Project", be assigned to preside over the hearing in this proceeding and that the testimony and exhibits presented in that proceeding be preserved to the extent appropriate. Hearings are scheduled for September 2006. Effective July 19, 2005, revenues from transactions under the IIC involving any Southern Company subsidiaries, including the Company, are subject to refund to the extent the FERC orders any changes to the IIC.

The Company believes that there is no meritorious basis for this proceeding and is vigorously defending itself in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in this proceeding, cannot now be determined.

Generation Interconnection Agreements

In July 2003, the FERC issued its final rule on the standardization of generation interconnection agreements and procedures (Order 2003). Order 2003 shifts much of the financial burden of new transmission investment from the generator to the transmission provider. The FERC has indicated that Order 2003, which was effective January 20, 2004, is to be applied prospectively to interconnection agreements. Subsidiaries of Tenaska, Inc., as counterparties to three previously executed interconnection agreements with subsidiaries of Southern Company, including the Company, have filed complaints at the FERC requesting that the FERC modify the agreements and that the Company refund a total of $7.9 million previously paid for interconnection facilities, with interest. The Company has opposed all such requests, and the proceedings are still pending. The impact of Order 2003 and its subsequent rehearings on the Company and the final results of these matters cannot be determined at this time.

Transmission

In December 1999, the FERC issued its final rule on Regional Transmission Organizations (RTOs). Since that time, there have been a number of additional proceedings at the FERC designed to encourage further voluntary formation of RTOs or to mandate their formation. However, at the current time, there are no active proceedings that would require the Company to participate in an RTO. Current FERC efforts that may potentially change the regulatory and/or operational structure of transmission include rules related to the standardization of generation interconnection, as well as an inquiry into, among other things, market power by vertically integrated utilities. See "Generation Interconnection Agreements" and "Market-Based Rate Authority" herein for additional information. The final outcome of these proceedings cannot now be determined. However, the Company's financial condition, results of operations, and cash flows could be adversely affected by future changes in the federal regulatory or operational structure of transmission.

PSC Matters

Merger

In connection with the Merger, the Company and Savannah Electric plan to establish a coastal regional organization for the Company that will be operating following completion of the Merger. Management expects that current Savannah Electric employees will fill most of the positions in the new regional organization.

While the Georgia PSC does not have specific approval authority over the merger of electric utilities, in January 2006, the Company and Savannah Electric filed an application with the Georgia PSC for certain approvals necessary to complete the Merger. In particular, the Company and Savannah Electric are seeking the approval of the Georgia PSC with respect to the following matters:

- the transfer of Savannah Electric's generating facilities and certification of the generating facilities as the Company's assets;
- amendments to the Company's Integrated Resource Plan to add the current Savannah Electric's customers and generating facilities;
- the transfer of Savannah Electric's assigned service territory to the Company;
- adoption of the Company's service rules and regulations to the current Savannah Electric customers;
- new fuel rate and base rate schedules that would apply to the Company's sale of electricity to the current Savannah Electric customers;
- adoption of a "merger transition adjustment" rate that would be used to more closely align Savannah Electric's existing base rates to those of the Company and a "merger transition credit" rate that would credit the additional revenues collected from former Savannah Electric customers to the Company's existing customers; and
- the issuance of additional shares of the Company's common stock to Southern Company in exchange for Southern Company's shares of Savannah Electric common stock.

The Company has also requested the Georgia PSC to better align the rates for Savannah Electric's customers with those of the Company. Currently, Savannah Electric customers pay slightly lower base rates and significantly higher fuel rates than the Company's customers. The overall effect is that Savannah Electric customers pay substantially higher overall costs for electricity. See "Fuel Cost Recovery" herein for additional information.

Rate Plans

In December 2004, the Georgia PSC approved the 2004 Retail Rate Plan for the three-year period ending December 31, 2007. Under the terms of the 2004 Retail Rate Plan, earnings are being evaluated annually against a retail return on common equity (ROE) range of 10.25 percent to 12.25 percent. Two-thirds of any earnings above 12.25 percent will be applied to rate refunds, with the remaining one-third retained by the Company. Retail rates were increased by approximately $194 million and customer fees were increased by approximately $9 million effective January 1, 2005 to cover the higher costs of purchased power; operation and maintenance expenses; environmental compliance; and continued investment in new generation, transmission and distribution facilities to support growth and ensure reliability. In 2005 the Company recorded $2.7 million revenue subject to refund for estimated earnings above 12.25 percent retail ROE.

The Company is required to file a general rate case by July 1, 2007, in response to which the Georgia PSC would be expected to determine whether the 2004 Retail Rate Plan should be continued, modified, or discontinued. Until then, the Company will not file for a general base rate increase unless its projected retail ROE falls below 10.25 percent. However, in connection with the Merger, the Company has requested Georgia PSC approval of a "merger transition adjustment" that would be used to adjust Savannah Electric's existing base rates to more closely match the existing base rates for the Company. See Note 3 to the financial statements under "Retail Regulatory Matters - Rate Plans" for additional information.

Plant McIntosh Construction Project

In December 2002 after a competitive bidding process, the Georgia PSC certified PPAs between Southern Power and the Company and Savannah Electric for capacity from Plant McIntosh Units 10 and 11, construction of which was completed in June 2005. In April 2003, Southern Power applied for FERC approval of these PPAs. In July 2003, the FERC accepted the PPAs to become effective June 1, 2005, subject to refund, and ordered that hearings be held. Intervenors opposed the FERC's acceptance of the PPAs, alleging that they did not meet the applicable standards for market-based rates between affiliates. To ensure the timely completion of the Plant McIntosh construction project and the availability of the units in the summer of 2005 for their retail customers, in May 2004, the Company and Savannah Electric requested the Georgia PSC to direct them to acquire the Plant McIntosh construction project. The Georgia PSC issued such an order and the transfer occurred on May 24, 2004 at a total cost of approximately $415 million, including

$14 million of transmission interconnection facilities. Subsequently, Southern Power filed a request to withdraw the PPAs and to terminate the ongoing FERC proceedings. In August 2004, the FERC issued a notice accepting the request to withdraw the PPAs and permitting such request to become effective by operation of law. However, the FERC made no determination on what additional steps may need to be taken with respect to testimony provided in the proceedings. See "FERC Matters - Intercompany Interchange Contract" above for additional information.

In connection with the 2004 Retail Rate Plan, the Georgia PSC approved the transfer of the Plant McIntosh construction project at a total fair market value of approximately $385 million. This value reflected an approximate $16 million disallowance, of which $13 million was attributable to the Company, and reduced the Company's 2004 net income by approximately $8 million. The Georgia PSC also certified a total completion cost of $547 million for the project. In June 2005, Plant McIntosh Units 10 and 11 were placed in service at a total cost that did not exceed the certified amount. Under the 2004 Retail Rate Plan, the Plant McIntosh revenue requirements impact will be reflected in the Company's rates evenly over the three years ending 2007. See Note 3 to the financial statements under "Retail Regulatory Matters -- Rate Plans" and "Plant McIntosh Construction Project" for additional information.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. In recent months, the Company has experienced higher than expected fuel costs for coal and natural gas. Those higher fuel costs have increased the under recovered fuel costs included in the balance sheets herein.

In May 2005, the Georgia PSC approved the Company's request to increase customer fuel rates by approximately 9.5 percent to recover under recovered fuel costs of approximately $508 million existing as of May 31, 2005 over a four-year period that began June 1, 2005. Under recovered fuel amounts for the period subsequent to June 1, 2005 totaled $327.5 million through December 31, 2005. The Georgia PSC's order instructed that such amounts be reviewed semi-annually beginning February 2006. If the amount under or over recovered exceeds $50 million at the evaluation date, the Company would be required to file for a temporary fuel rate change. In addition, Savannah Electric's under recovered fuel costs totaled $77.7 million at December 31, 2005. In accordance with the Georgia PSC order, Savannah Electric was scheduled to file an additional request for a fuel cost recovery increase in January 2006. The Company has agreed with a Georgia PSC staff recommendation to forego the temporary fuel rate process, and Savannah Electric has postponed its scheduled filing. Instead, the Company and Savannah Electric will file a combined request in March 2006 to increase the Company's fuel cost recovery rate.

The case will seek approval of a fuel cost recovery rate based upon future fuel cost projections for the combined Company and Savannah Electric generating fleet as well as the under recovered fuel balances existing at June 30, 2006. The new fuel cost recovery rate would be billed beginning in July 2006 to all of the Company's customers, including the existing Savannah Electric customers. Under recovered amounts as of the date of the Merger will be paid by the appropriate customer groups.

In August 2005, the Georgia PSC initiated an investigation of Savannah Electric's fuel practices. In February 2006, an investigation of the Company's fuel practices was initiated. The Company and Savannah Electric are responding to data requests and cooperating in the investigations. The final outcome of this matter cannot now be determined.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable cost and amounts billed in current regulated rates. Accordingly, any increase in the billing factor would have no significant effect on the Company's revenues or net income, but would increase annual cash flow.

Nuclear

As part of a potential expansion of Plant Vogtle, the Company and Southern Nuclear have notified the Nuclear Regulatory Commission (NRC) of their intent to apply for an early site permit (ESP) this year and a combined construction and operating license (COL) in 2008. In addition, a reactor design from Westinghouse Electric Company has been selected and a purchase agreement is being negotiated. Participation agreements have been reached with each of the existing Plant Vogtle co-owners. See Note 4 to the financial statements for additional information on

these co-owners. At this point, no final decision has been made regarding actual construction. The NRC's streamlined licensing process for new nuclear units allows utilities to seek regulatory approval at various stages. These stages include design certification, which is obtained by the reactor vendor, and the ESP and COL, which are each obtained by the owner-operators of the units. An ESP indicates site approval is obtained before a company decides to build and the COL provides regulatory approval for building and operating the plant. In addition, any generation by the Company must be certified by the Georgia PSC.

Southern Company also is participating in NuStart Energy Development, LLC (NuStart Energy), a broad-based nuclear industry consortium formed to share the cost of developing a COL and the related NRC review. NuStart Energy plans to complete detailed engineering design work and to prepare COL applications for two advanced reactor designs, then to choose one of the applications and file it for NRC review and approval. The COL ultimately is expected to be transferred to one or more of the consortium companies; however, at this time, none of them have committed to build a new nuclear plant.

Other Matters

In accordance with Financial Accounting Standards Board (FASB) Statement No. 87, Employers' Accounting for Pensions, the Company recorded non-cash pension income, before tax, of approximately $21 million, $35 million, and $54 million in 2005, 2004, and 2003, respectively. Postretirement benefit costs for the Company were $47 million, $44 million, and $41 million in 2005, 2004, and 2003, respectively. Both pension and postretirement costs are expected to trend upward. Such amounts are dependent on several factors including trust earnings and changes to the plans. A portion of pension income and postretirement benefit costs is capitalized based on construction-related labor charges. For the Company, pension income or expense and postretirement benefit costs are a component of the regulated rates and generally do not have a long-term effect on net income. For more information regarding pension and postretirement benefits, see Note 2 to the financial statements.

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

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

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

Electric Utility Regulation

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

As reflected in Note 1 to the financial statements under "Regulatory Assets and Liabilities," significant regulatory assets and liabilities have been recorded.

Management reviews the ultimate recoverability of these regulatory assets and liabilities based on applicable regulatory guidelines and accounting principles generally accepted in the United States. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

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

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

Unbilled Revenues

Revenues related to the sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated. Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, power delivery volume, and other operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.

New Accounting Standards

Income Taxes

In December 2004, the FASB issued FASB Staff Position 109-1, Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004 (FSP 109-1), which requires that the generation deduction be accounted for as a special tax deduction rather than as a tax rate reduction. The Company adopted FSP 109-1 in the first quarter of 2005 with no material impact on its financial statements.

Conditional Asset Retirement Obligations

Effective December 31, 2005, the Company adopted the provision of FASB Interpretation No. 47, Conditional Asset Retirement Obligations (FIN 47), which requires that an asset retirement obligation be recorded even though the timing and/or method of settlement are conditional on future events. Prior to December 2005, the Company did not recognize asset retirement obligations for asbestos removal because the timing of retirements was dependent on future events. For additional information, see Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal."

At December 31, 2005, the Company recorded additional asset retirement obligations (and assets) of approximately $91 million. The adoption of FIN 47 did not have any effect on the Company's income statement.

Stock Options

On January 1, 2006, the Company adopted FASB Statement No. 123R, Share-Based Payment, on a modified prospective basis. This statement requires that compensation cost relating to share-based payment transactions be recognized in financial statements. That cost will be measured based on the grant date fair value of the equity or liability instruments issued. Although the compensation expense required under the revised statement differs slightly, the impacts on the Company's financial statements are similar to the pro forma disclosures included in Note 1 to the financial statements under "Stock Options."

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition continued to be stable at December 31, 2005 with emphasis on cost control measures combined with significantly lower costs of capital, achieved through the refinancing and/or redemption of higher-cost securities. Cash flow from operations increased $56 million resulting primarily from increased retail operating revenues (see RESULTS OF OPERATIONS herein), partially offset by the increase in under recovered deferred fuel costs.

Fuel costs are generally recoverable in future periods and are reflected on the balance sheets as under recovered regulatory clause revenues. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information.

In 2005, gross utility plant additions were $906 million. These additions were primarily related to Plant McIntosh Units 10 and 11, transmission and distribution facilities, nuclear fuel, and equipment to comply with environmental standards. The majority of funds needed for gross property additions for the last several years have been provided from operating activities and capital contributions from Southern Company. The statements of cash flows provide additional details.

The Company's ratio of common equity to total capitalization -- including short-term debt -- was 48.3 percent in 2005, 47.7 percent in 2004, and 48.3 percent in 2003. The Company has received investment grade ratings from the major rating agencies.

Sources of Capital

The Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows. However, the type and timing of any future financings, if needed, will depend on market conditions, regulatory approval, and other factors.

The issuance of long-term securities by the Company is subject to the approval of the Georgia PSC. In addition, the issuance of short-term debt securities by the Company is subject to regulatory approval by the FERC following the repeal of the Public Utility Holding Company Act of 1935, as amended, on February 8, 2006. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the appropriate regulatory authorities, as well as the amounts registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company.

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

To meet short-term cash needs and contingencies, the Company had credit arrangements with banks totaling $780 million, of which $778 million was unused, at the beginning of 2006. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper and extendible commercial notes at the request and for the benefit of the Company and the other retail operating companies.

Proceeds from such issuances for the benefit of the Company are loaned directly to the Company and are not commingled with proceeds from issuances for the benefits of any other operating company. The obligations of each company under these arrangements are several; there is no cross affiliate credit support. As of December 31, 2005, the Company had outstanding $268 million of commercial paper and no extendible commercial notes.

At the beginning of 2006, bank credit arrangements were as follows:

		Expires		
Total	Unused	2006	2007	2010
		(in millions)		
$780	$778	$70	$350	$360

The credit arrangements that expire in 2006 allow for the execution of term loans for an additional two-year period.

Financing Activities

During 2005, the Company issued $810 million of long-term debt. The issuances were used to refund $635 million of long-term debt and to fund the Company's ongoing construction program.

Subsequent to December 31, 2005, the Company redeemed all of its outstanding preferred stock at a redemption price of $107 per share.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- or Baa3 or below. Generally, collateral may be provided for by a Southern Company guaranty, letter of credit, or cash. These contracts are primarily for physical electricity purchases and sales. At December 31, 2005, the maximum potential collateral requirements at a BBB- or Baa3 rating were approximately $6 million. The maximum potential collateral requirements at a rating below BBB- or Baa3 were approximately $245 million.

The Company is also party to certain derivative agreements that could require collateral and/or accelerated payment in the event of a credit rating change to below investment grade. These agreements are primarily for natural gas price risk management activities. At December 31, 2005, the Company had no material exposure related to these agreements.

Market Price Risk

Due to cost-based rate regulation, the Company has limited exposure to market rate 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 and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress tests, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company has entered into forward starting interest rate swaps that have been designated as hedges. These swaps have a notional amount of $300 million and are related to anticipated debt issuances over the next two years. The weighted average interest rate on outstanding variable long-term debt that has not been hedged at January 1, 2006 was 3.56 percent. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $3.3 million at January 1, 2006. For further information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

To mitigate residual risks relative to movements in electricity prices, the Company enters into fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, into similar contracts for gas purchases.

The Company has implemented a fuel hedging program at the instruction of the Georgia PSC. Fair

value of changes in energy-related derivative contracts and year-end valuations were as follows at December 31:

	Changes in Fair Value	
	2005	2004
	(in millions)	
Contracts beginning of year	**$5.8**	$ 3.2
Contracts realized or settled	**(40.0)**	(12.2)
Current period changes (a)	**60.8**	14.8
Contracts end of year	**$26.6**	$ 5.8

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

	Source of 2005 Year-End Valuation Prices		
	Total	Maturity	
	Fair Value	Year 1	1-3 Years
		(in millions)	
Actively quoted	**$26.8**	$16.4	$10.4
External sources	**(0.2)**	(0.2)	-
Contracts end of year	**$26.6**	$16.2	$10.4

Unrealized gains and losses from mark to market adjustments on derivative contracts related to the Company's fuel hedging programs are recorded as regulatory assets and liabilities. Realized gains and losses from these programs are included in fuel expense and are recovered through the Company's fuel cost recovery mechanism. Of the net gains, the Company is allowed to retain 25 percent in earnings. In 2005, the Company had a total net gain of $64.1 million, of which the Company retained $16.0 million. See Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Hedging Program" for additional information. Gains and losses on derivative contracts that are not designated as hedges are recognized in the statements of income as incurred. At December 31, 2005, the fair value of derivative energy contracts was reflected in the financial statements as follows:

	Amounts
	(in millions)
Regulatory liabilities, net	$26.7
Net income	(0.1)
Total fair value	$26.6

Unrealized gains (losses) recognized in income in 2005, 2004, and 2003 were not material. The Company is exposed to market price risk in the event of nonperformance by counterparties to the derivative energy contracts. The Company's policy is to enter into agreements with counterparties that have investment grade credit ratings by Moody's and Standard & Poor's or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to be $1.3 billion for 2006, $1.4 billion for 2007, and $1.3 billion for 2008. Environmental expenditures included in these amounts are $410 million, $674.6 million, and $515.8 million for 2006, 2007, and 2008, respectively. Actual construction costs may vary from this estimate because of changes in such factors as: business conditions; environmental regulations; nuclear plant regulations; FERC rules and transmission regulations; load projections; the cost and efficiency of construction labor, equipment, and materials; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

As a result of requirements by the NRC, the Company has established external trust funds for nuclear decommissioning costs. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning." Also as discussed in Note 1 to the financial statements under "Nuclear Fuel Disposal Costs," in 1993 the DOE implemented a special assessment over a 15-year period on utilities with nuclear plants to be used for the decontamination and decommissioning of its nuclear fuel enrichment facilities.

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the Georgia PSC and the FERC.

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

Amounts in the following chart exclude any effects on the Company of the Merger.

Contractual Obligations

	2006	2007-2008	2009-2010	After 2010	Total
			(in millions)		
Long-term debt [a] --					
Principal	$153	$306	$282	$4,563	$5,304
Interest	265	496	468	4,989	6,218
Preferred stock	15	-	-	-	15
Commodity derivative obligations[b]	12	-	-	-	12
Operating leases	34	58	44	58	194
Purchase commitments[c] --					
Capital [d]	1,251	2,738	2,421	-	6,410
Coal	1,579	2,220	694	40	4,533
Nuclear fuel	44	42	25	64	175
Natural gas[e]	577	525	511	2,047	3,660
Purchased power	343	689	559	994	2,585
Long-term service agreements	7	18	24	144	193
Trusts[f] --					
Nuclear decommissioning	7	14	14	117	152
Postretirement benefits	18	41	-	-	59
DOE assessments	4	-	-	-	4
Total	$4,309	$7,147	$5,042	$13,016	$29,514

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2006, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest risk.

(b) For additional information see Notes 1 and 6 to the financial statements herein.

(c) The Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses for the last three years were $1.5 billion, $1.4 billion, and $1.2 billion, respectively.

(d) The Company forecasts capital expenditures over a five-year period. Amounts represent current estimates of total expenditures, excluding those amounts related to contractual purchase commitments for uranium and nuclear fuel conversion, enrichment, and fabrication services. At December 31, 2005, significant purchase commitments were outstanding in connection with the construction program.

(e) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on the New York Mercantile Exchange future prices at December 31, 2005.

(f) Projections of nuclear decommissioning trust contributions are based on the 2004 Retail Rate Plan. The Company forecasts postretirement trust contributions over a three-year period. No contributions related to the Company's pension trust are currently expected during this period. See Note 2 to the financial statements for additional information related to the pension and postretirement plans, including estimated benefit payments. Certain benefit payments will be made through the related trusts. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2005 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales growth, storm cost recovery and repairs, environmental regulations and expenditures, the Company's projections for postretirement benefit trust contributions, financing activities, access to sources of capital, the proposed merger of Savannah Electric and the Company, the impacts of the adoption of new accounting rules, completion of construction projects, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will", "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory change, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, and implementation of the Energy Policy Act of 2005, and also changes in environmental, tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including FERC matters and the pending EPA civil action against the Company;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and population, and business growth (and declines);
- available sources and costs of fuels;
- ability to control costs;
- investment performance of the Company's employee benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate cases related to fuel cost recovery;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due;
- the ability to obtain new short- and long-term contracts with neighboring utilities;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents similar to the August 2003 power outage in the Northeast;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports, including the Form 10-K, filed by the Company from time to time with the Securities and Exchange Commission.

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

STATEMENTS OF INCOME

For the Years Ended December 31, 2005, 2004, and 2003

Georgia Power Company 2005 Annual Report

	2005	2004	2003
		(in thousands)	
Operating Revenues:			
Retail sales	**$5,642,812**	$4,776,985	$4,309,972
Sales for resale --			
Non-affiliates	**519,673**	246,545	259,376
Affiliates	**264,989**	166,245	174,855
Other revenues	**206,729**	181,033	169,304
Total operating revenues	**6,634,203**	5,370,808	4,913,507
Operating Expenses:			
Fuel	**1,830,829**	1,232,496	1,103,963
Purchased power --			
Non-affiliates	**408,563**	304,978	258,621
Affiliates	**761,466**	671,098	516,944
Other operations	**949,722**	902,167	827,972
Maintenance	**531,168**	498,114	419,206
Depreciation and amortization	**504,248**	275,488	349,984
Taxes other than income taxes	**259,825**	227,806	212,827
Total operating expenses	**5,245,821**	4,112,147	3,689,517
Operating Income	**1,388,382**	1,258,661	1,223,990
Other Income and (Expense):			
Allowance for equity funds used during construction	**26,808**	26,659	10,752
Interest income	**6,281**	6,657	15,625
Interest expense, net of amounts capitalized	**(221,199)**	(182,370)	(182,583)
Interest expense to affiliate trusts	**(59,510)**	(44,565)	-
Distributions on mandatorily redeemable preferred securities	**-**	(15,839)	(59,675)
Other income (expense), net	**5,742**	(11,362)	(10,551)
Total other income and (expense)	**(241,878)**	(220,820)	(226,432)
Earnings Before Income Taxes	**1,146,504**	1,037,841	997,558
Income taxes	**430,812**	379,170	366,311
Net Income	**715,692**	658,671	631,247
Dividends on Preferred Stock	**693**	670	670
Net Income After Dividends on Preferred Stock	**$714,999**	$658,001	$630,577

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2005, 2004, and 2003
Georgia Power Company 2005 Annual Report

	2005	2004	2003
		(in thousands)	
Operating Activities:			
Net income	**$ 715,692**	$ 658,671	$ 631,247
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization	**592,264**	361,958	424,321
Deferred income taxes and investment tax credits, net	**231,708**	251,623	199,265
Deferred expenses - affiliates	**1,268**	(10,563)	(7,399)
Allowance for equity funds used during construction	**(26,808)**	(26,659)	(10,752)
Pension, postretirement, and other employee benefits	**(19,468)**	(15,868)	(30,225)
Tax benefit of stock options	**15,711**	9,701	11,649
Other, net	**(11,068)**	(19,764)	18,929
Changes in certain current assets and liabilities --			
Receivables	**(591,498)**	(227,204)	(4,395)
Fossil fuel stock	**2,528**	(46,730)	(17,490)
Materials and supplies	**(53,942)**	618	(7,677)
Prepaid income taxes	**(43,626)**	14,358	(3,951)
Other current assets	**4,108**	(23,672)	1,599
Accounts payable	**110,118**	132,001	(62,553)
Accrued taxes	**85,098**	(64,563)	52,348
Accrued compensation	**3,822**	(6,664)	(3,111)
Other current liabilities	**33,289**	5,836	19,845
Net cash provided from operating activities	**1,049,196**	993,079	1,211,650
Investing Activities:			
Property additions	**(842,870)**	(741,151)	(717,993)
Nuclear decommissioning trust fund purchases	**(381,235)**	(541,048)	(656,806)
Nuclear decommissioning trust fund sales	**372,536**	532,349	648,107
Purchase of property from affiliates	**-**	(339,750)	(2)
Cost of removal net of salvage	**(29,428)**	(21,756)	(28,265)
Change in construction payables, net of joint owner portion	**4,037**	413	(32,223)
Other	**(315)**	(4,961)	1,008
Net cash used for investing activities	**(877,275)**	(1,115,904)	(786,174)
Financing Activities:			
Increase (decrease) in notes payable, net	**59,509**	70,956	(220,400)
Proceeds --			
Senior notes	**625,000**	600,000	1,000,000
Pollution control bonds	**185,000**	-	-
Mandatorily redeemable preferred securities	**-**	200,000	-
Capital contributions from parent company	**149,034**	260,068	40,809
Redemptions --			
Pollution control bonds	**(185,000)**	-	-
Senior notes	**(450,000)**	(200,000)	(665,000)
Mandatorily redeemable preferred securities	**-**	(200,000)	-
Payment of preferred stock dividends	**(546)**	(654)	(696)
Payment of common stock dividends	**(556,100)**	(565,500)	(565,800)
Other	**(21,679)**	(17,247)	(22,563)
Net cash provided from (used for) financing activities	**(194,782)**	147,623	(433,650)
Net Change in Cash and Cash Equivalents	**(22,861)**	24,798	(8,174)
Cash and Cash Equivalents at Beginning of Year	**33,497**	8,699	16,873
Cash and Cash Equivalents at End of Year	**$ 10,636**	$ 33,497	$ 8,699
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $10,871, $8,920, and $5,428 capitalized, respectively)	**$250,445**	$228,190	$215,463
Income taxes (net of refunds)	**207,973**	127,115	145,048

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

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BALANCE SHEETS
At December 31, 2005 and 2004
Georgia Power Company 2005 Annual Report

Assets	2005	2004
		(in thousands)
Current Assets:		
Cash and cash equivalents	**$ 10,636**	$ 33,497
Receivables --		
Customer accounts receivable	**418,154**	317,937
Unbilled revenues	**141,875**	140,027
Under recovered regulatory clause revenues	**454,683**	345,542
Other accounts and notes receivable	**110,397**	94,377
Affiliated companies	**84,597**	17,042
Accumulated provision for uncollectible accounts	**(8,647)**	(7,100)
Fossil fuel stock, at average cost	**181,739**	184,267
Vacation pay	**59,190**	57,372
Materials and supplies, at average cost	**323,908**	270,422
Prepaid expenses	**70,825**	32,695
Other	**50,248**	28,262
Total current assets	**1,897,605**	1,514,340
Property, Plant, and Equipment:		
In service	**19,603,249**	18,681,533
Less accumulated provision for depreciation	**7,575,926**	7,217,607
	12,027,323	11,463,926
Nuclear fuel, at amortized cost	**134,798**	124,745
Construction work in progress	**563,155**	766,140
Total property, plant, and equipment	**12,725,276**	12,354,811
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**68,188**	66,192
Nuclear decommissioning trusts, at fair value	**486,591**	459,194
Other	**71,468**	64,571
Total other property and investments	**626,247**	589,957
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**500,882**	505,664
Prepaid pension costs	**476,458**	450,270
Deferred under recovered regulatory clause revenues	**295,116**	-
Other regulatory assets	**330,483**	246,462
Other	**195,716**	160,834
Total deferred charges and other assets	**1,798,655**	1,363,230
Total Assets	**$17,047,783**	$15,822,338

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

BALANCE SHEETS
At December 31, 2005 and 2004
Georgia Power Company 2005 Annual Report

Liabilities and Stockholder's Equity	2005	2004
		(in thousands)
Current Liabilities:		
Securities due within one year	$ 167,317	$ 452,498
Notes payable	267,743	208,233
Accounts payable --		
Affiliated	285,019	194,253
Other	360,455	310,763
Customer deposits	129,293	115,661
Accrued taxes --		
Income taxes	150,896	78,269
Other	204,778	129,520
Accrued interest	88,885	74,529
Accrued vacation pay	45,602	44,894
Accrued compensation	137,303	127,340
Other	120,312	83,632
Total current liabilities	1,957,603	1,819,592
Long-term Debt (See accompanying statements)	4,179,218	3,709,852
Long-term Debt Payable to Affiliated Trusts (See accompanying statements)	969,073	969,073
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	2,730,303	2,556,040
Deferred credits related to income taxes	158,759	170,973
Accumulated deferred investment tax credits	287,726	300,018
Employee benefit obligations	358,137	331,002
Asset retirement obligations	627,465	504,515
Other cost of removal obligations	404,614	411,692
Other regulatory liabilities	97,015	84,678
Other	63,335	59,733
Total deferred credits and other liabilities	4,727,354	4,418,651
Total Liabilities	11,833,248	10,917,168
Preferred Stock (See accompanying statements)	-	14,609
Common Stockholder's Equity (See accompanying statements)	5,214,535	4,890,561
Total Liabilities and Stockholder's Equity	$17,047,783	$15,822,338
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2005 and 2004
Georgia Power Company 2005 Annual Report

	2005	2004	2005	2004
	(in thousands)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable --				
5.50% due December 1, 2005	**$ -**	$ 150,000		
Variable rate (1.66% to 1.96% at 1/1/05) due 2005	**-**	300,000		
6.20% due February 1, 2006	**150,000**	150,000		
4.875% due July 15, 2007	**300,000**	300,000		
4.10% due August 15, 2009	**125,000**	125,000		
Variable rate (4.53% at 1/1/06) due 2009	**150,000**	150,000		
4.00% to 6.00% due 2011-2045	**1,850,000**	1,225,000		
Total long-term notes payable	**2,575,000**	2,400,000		
Other long-term debt --				
Pollution control revenue bonds -- non-collateralized:				
2.83% to 5.45% due 2012-2034	**812,560**	812,560		
Variable rate (2.82% to 3.08% at 1/1/06) due 2011-2032	**873,330**	873,330		
Total other long-term debt	**1,685,890**	1,685,890		
Capitalized lease obligations	**74,484**	76,982		
Unamortized debt premium (discount), net	**(3,448)**	(522)		
Total long-term debt (annual interest requirement -- $205.5 million)	**4,331,926**	4,162,350		
Less amount due within one year	**152,708**	452,498		
Long-term debt excluding amount due within one year	**4,179,218**	3,709,852	**40.3%**	38.7%
Long-term Debt Payable to Affiliated Trusts:				
4.88% to 7.13% due 2042 (annual interest requirement -- $59.5 million)	**969,073**	**969,073**	**9.4**	10.1
Cumulative Preferred Stock:				
$100 stated value at 4.60%				
Authorized -- 5,000,000 shares				
Outstanding -- 145,689 shares (annual dividend requirement -- $0.7 million)	**14,609**	14,609		
Less amount due within one year	**14,609**	-		
Total cumulative preferred stock excluding amount due within one year	**-**	14,609	**0.0**	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	**2,643,012**	2,478,268		
Retained earnings	**2,261,698**	2,102,798		
Accumulated other comprehensive income (loss)	**(34,425)**	(34,755)		
Total common stockholder's equity	**5,214,535**	4,890,561	**50.3**	51.0
Total Capitalization	**$10,362,826**	$9,584,095	**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, 2005, 2004, and 2003

Georgia Power Company 2005 Annual Report

	Common Stock	Paid-In Capital	Retained Earnings	Other Comprehensive Income (loss)	Total
			(in thousands)		
Balance at December 31, 2002	$344,250	$2,156,080	$1,945,520	$(11,403)	$4,434,447
Net income after dividends on preferred stock	-	-	630,577	-	630,577
Capital contributions from parent company	-	52,458	-	-	52,458
Other comprehensive income (loss)	-	-	-	(11,471)	(11,471)
Cash dividends on common stock	-	-	(565,800)	-	(565,800)
Balance at December 31, 2003	**344,250**	**2,208,538**	**2,010,297**	**(22,874)**	**4,540,211**
Net income after dividends on preferred stock	-	-	658,001	-	658,001
Capital contributions from parent company	-	269,769	-	-	269,769
Other comprehensive income (loss)	-	-	-	(11,881)	(11,881)
Cash dividends on common stock	-	-	(565,500)	-	(565,500)
Other	-	(39)	-	-	(39)
Balance at December 31, 2004	**344,250**	**2,478,268**	**2,102,798**	**(34,755)**	**4,890,561**
Net income after dividends on preferred stock	-	-	**714,999**	-	**714,999**
Capital contributions from parent company	-	**164,745**	-	-	**164,745**
Other comprehensive income (loss)	-	-	-	**330**	**330**
Cash dividends on common stock	-	-	**(556,100)**	-	**(556,100)**
Other	-	**(1)**	**1**	-	-
Balance at December 31, 2005	**$344,250**	**$2,643,012**	**$2,261,698**	**$(34,425)**	**$5,214,535**

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

STATEMENTS OF COMPREHENSIVE INCOME

For the Years Ended December 31, 2005, 2004, and 2003

Georgia Power Company 2005 Annual Report

	2005	2004	2003
		(in thousands)	
Net income after dividends on preferred stock	**$714,999**	$658,001	$630,577
Other comprehensive income (loss):			
Change in additional minimum pension liability, net of tax of $(1,981), $(3,861) and $(5,133), respectively	**(3,140)**	(6,122)	(8,138)
Change in fair value of marketable securities, net of tax of $317 and $(114)	**501**	(181)	-
Changes in fair value of qualifying hedges, net of tax of $1,214, $(5,046) and $(3,241), respectively	**1,925**	(7,999)	(5,550)
Less: Reclassification adjustment for amounts included in net income, net of tax of $848, $1,528 and $1,208, respectively	**1,044**	2,421	2,217
Total other comprehensive income (loss)	**330**	(11,881)	(11,471)
Comprehensive Income	**$715,329**	$646,120	$619,106

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Georgia Power Company (Company) is a wholly owned subsidiary of Southern Company, which is the parent company of five retail operating companies, Southern Power Company (Southern Power), Southern Company Services (SCS), Southern Communications Services (SouthernLINC Wireless), Southern Company Holdings (Southern Holdings), Southern Nuclear Operating Company (Southern Nuclear), Southern Telecom, and other direct and indirect subsidiaries. The retail operating companies -- Alabama Power, the Company, Gulf Power, Mississippi Power, and Savannah Electric -- provide electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast. Southern Power constructs, owns, and manages Southern Company's competitive generation assets and sells electricity at market-based rates in the wholesale market. Contracts among the retail operating companies and Southern Power -- related to jointly owned generating facilities, interconnecting transmission lines, or the exchange of electric power -- are regulated by the Federal Energy Regulatory Commission (FERC). SCS -- the system service company -- provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications services to the retail operating companies and also markets these services to the public within the Southeast. Southern Telecom provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding subsidiary for Southern Company's investments in synthetic fuels and leveraged leases and various other energy-related businesses. Southern Nuclear operates and provides services to Southern Company's nuclear power plants. In January 2006, Southern Company completed the sale of substantially all the assets of Southern Company Gas, its competitive retail natural gas marketing subsidiary.

The equity method is used for subsidiaries in which the Company has significant influence but does not control and for variable interest entities where the Company is not the primary beneficiary. Certain prior years' data presented in the financial statements have been reclassified to conform to current year presentation.

Southern Company was registered as a holding company under the Public Utility Holding Company Act of 1935, as amended (PUHCA), until its repeal on February 8, 2006, and Southern Company and its subsidiaries, including the Company, were subject to the regulatory provisions of the PUHCA. The Company is subject to regulation by the FERC and the Georgia Public Service Commission (PSC). The Company follows accounting principles generally accepted in the United States and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires the use of estimates and the actual results may differ from those estimates.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, purchasing, accounting and statistical analysis, finance and treasury, tax, information resources, marketing, auditing, insurance and pension administration, human resources, systems and procedures, and other services with respect to business and operations and power pool operations. Costs for these services amounted to $330 million in 2005, $292 million in 2004, and $303 million in 2003. Cost allocation methodologies used by SCS were approved by the Securities and Exchange Commission prior to the repeal of the PUHCA 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 $328 million in 2005, $311 million in 2004, and $289 million in 2003.

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. Billings under these agreements with Southern Power amounted to $5.2 million in 2005, $4.8 million in 2004, and $5.3 million in 2003.

The Company has an agreement with SouthernLINC Wireless under which the Company receives digital wireless communications services and purchases digital equipment. Costs for these services amounted to $7.3 million in 2005, $7.7 million in 2004, and $7.4 million in 2003.

Southern Company holds a 30 percent ownership in Alabama Fuel Products, LLC (AFP), which produces synthetic fuel. The Company has an agreement with an indirect subsidiary of Southern Company that provides services for AFP. Under this agreement, the Company provides certain accounting functions, including processing and paying fuel transportation invoices, and the Company is reimbursed for its expenses. Amounts billed under this agreement totaled approximately $61 million in 2005, $53 million in 2004, and $38 million in 2003. In addition, the Company purchases synthetic fuel from AFP for use at plants Branch, McDonough, and Bowen. Fuel purchases totaled $216 million in 2005, $163 million in 2004, and $91 million in 2003.

The Company has entered into several purchased power agreements (PPAs) with Southern Power for capacity and energy. Expenses associated with these PPAs were $419 million, $282 million, and $203 million in 2005, 2004, and 2003, respectively. Additionally, the Company recorded a reduction of $1 million and an increase of $11 million of prepaid capacity expenses included on the balance sheets at December 31, 2005 and 2004, respectively. See Note 7 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, the Company operates Plant Scherer, and Gulf Power reimburses the Company for its proportionate share of the related expenses which were $4.3 million in 2005, $6.8 million in 2004, and $4.9 million in 2003. The Company has an agreement with Savannah Electric under which the Company jointly owns a portion of Plant McIntosh. Under this agreement, Savannah Electric operates Plant McIntosh, and the Company reimburses Savannah Electric for its proportionate share of the related expenses which were $5.5 million in 2005, $3.3 million in 2004, and $3.7 million in 2003. See Note 4 for additional information.

The Company provides incidental services to other Southern Company subsidiaries which are generally minor in duration and amount. However, with the hurricane damage experienced by Alabama Power, Gulf Power, and Mississippi Power in the last two years, assistance provided to aid in storm restoration, including company labor, contract labor, and materials, has caused an increase in these activities. The total amount of storm assistance provided to Alabama Power, Gulf Power, and Mississippi Power in 2005 was $4.1 million, $4.4 million, and $55 million, respectively. The total amount of storm assistance provided to Alabama Power and Gulf Power in 2004 was $4.1 million and $6.4 million, respectively. These activities were billed at cost.

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

The retail operating companies, including the Company, and Southern Power 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 7 under "Fuel Commitments" for additional information.

The Company has entered into an agreement to merge with Savannah Electric. See Note 3 under "Retail Regulatory Matters – Merger" 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.

Regulatory assets and (liabilities) reflected in the Company's balance sheets at December 31 relate to the following:

	2005	2004	Note
	(in millions)		
Deferred income tax charges	$ 501	$506	(a)
Premium on reacquired debt	170	177	(b)
Corporate building lease	52	53	(e)
Vacation pay	59	57	(d)
Postretirement benefits	18	20	(e)
DOE assessments	6	10	(c)
Generating plant outage costs	46	40	(g)
Other regulatory assets	33	11	(e)
Asset retirement obligation	65	(20)	(a)
Other cost of removal obligations	(404)	(412)	(a)
Deferred income tax credits	(159)	(171)	(a)
Environmental remediation	(19)	(22)	(f)
Purchased power	(33)	-	(f)
Other regulatory liabilities	(30)	(6)	(e)
Total	$ 305	$243	

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

(a) Asset retirement and removal liabilities are recorded, deferred income tax assets are recovered, and deferred tax liabilities are amortized over the related property lives, which may range up to 60 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities.

(b) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue which may range up to 50 years.

(c) Assessments for the decontamination and decommissioning of the DOE's nuclear fuel enrichment facilities are recorded annually from 1993 through 2006.

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

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

(f) Amortized over a three-year period ending in 2007. See Note 3 under "Retail Regulatory Matters - Rate Plans."

(g) See "Property, Plant, and Equipment" herein.

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, including plant, exists and, if impaired, write down the assets to their fair value. All regulatory assets and liabilities are reflected in rates.

Revenues

Energy and other revenues are recognized as services are provided. Unbilled revenues are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between the actual recoverable costs and amounts billed in current regulated rates.

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

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense includes the cost of purchased emission allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel. Total charges for nuclear fuel included in fuel expense amounted to $70 million in 2005, $73 million in 2004, and $74 million in 2003.

Nuclear Fuel Disposal Costs

The Company has contracts with the U.S. Department of Energy (DOE) that provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent nuclear fuel in 1998 as required by the contracts, and the Company is pursuing legal remedies against the government for breach of contract. Sufficient pool storage capacity for spent fuel is available at Plant Vogtle to maintain full-core discharge capability for both units into 2015. Construction of an on-site dry storage facility at Plant Vogtle is expected to begin in sufficient time to maintain pool full-core discharge capability. At Plant Hatch, an on-site dry storage facility is operational and can be expanded to accommodate spent fuel through the life of the plant.

Also, the Energy Policy Act of 1992 required the establishment of a Uranium Enrichment Decontamination and Decommissioning Fund, which is funded in part by a special assessment on utilities with nuclear plants. This assessment has been paid over a 15-

year period; the final installment is scheduled to occur in 2006. 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 interest, estimates its remaining liability at December 31, 2005 under this law to be approximately $4 million.

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.

Manufacturer's Tax Credits

The State of Georgia provides a tax credit for qualified investment property to manufacturing companies that construct new facilities. The credit ranges from 1 percent to 8 percent of qualified construction expenditures depending upon the county in which the new facility is located. The Company's policy is to recognize these credits when management believes that they are more likely than not to be allowed by the Georgia Department of Revenue. Manufacturer's tax credits of $12.5 million, $12.9 million, and $12.0 million were recorded in 2005, 2004, and 2003, respectively.

Property, Plant, and Equipment

The Company's property, plant, and equipment consisted of the following at December 31 (in millions):

	2005	2004
Generation	**$ 9,571**	$ 9,002
Transmission	**2,994**	2,870
Distribution	**5,953**	5,744
General	**1,057**	1,038
Plant acquisition adjustment	**28**	28
Total plant in service	**$ 19,603**	$18,682

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

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense as incurred or performed with the exception of certain generating plant maintenance costs. As mandated by the Georgia PSC, the Company defers and amortizes nuclear refueling costs over the unit's operating cycle before the next refueling. The refueling cycles are 18 and 24 months for plants Vogtle and Hatch, respectively. In accordance with the Georgia PSC 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.

Depreciation and Amortization

Depreciation of the original cost of plant in service is provided primarily by using composite straight-line rates, which approximated 2.6 percent in 2005, 2.6 percent in 2004, and 2.7 percent in 2003. Depreciation studies are conducted periodically to update the composite rates that are approved by the Georgia PSC. In connection with the new retail rate plan for the Company ending December 31, 2007 (2004 Retail Rate Plan), effective January 1, 2005, the depreciation rates were revised by the Georgia PSC. The revised depreciation rates had no material impact on the Company's financial statements.

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.

Under the three-year retail rate plan for the Company ending December 31, 2004 (2001 Retail Rate Plan), the Company discontinued recording accelerated depreciation and amortization. Also, the Company was ordered to amortize $333 million, the cumulative balance previously expensed, equally over three years as a credit to amortization expense beginning January

2002. Additionally, the Company was ordered to recognize new Georgia PSC certified purchased power costs in rates evenly over the three years covered by the 2001 Retail Rate Plan. As a result of the purchased power regulatory adjustment, the Company recorded amortization expenses of $14 million in 2003. The Company recorded a credit to amortization expense of $77 million in 2004. See Note 3 under "Retail Regulatory Matters - Rate Plans" for additional information.

Asset Retirement Obligations and Other Costs of Removal

Effective January 1, 2003, the Company adopted FASB Statement No. 143, Accounting for Asset Retirement Obligations. Statement No. 143 established new accounting and reporting standards for legal obligations associated with the ultimate costs of retiring long-lived assets. The present value of the ultimate costs for an asset's future retirement is recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In addition, effective December 31, 2005, the Company adopted the provisions of FASB Interpretation No. 47, Conditional Asset Retirement Obligations (FIN 47), which requires that an asset retirement obligation be recorded even though the timing and/or method of settlement are conditional on future events. Prior to December 2005, the Company did not recognize asset retirement obligations for asbestos removal because the timing of their retirements was dependent on future events. The Company has received approval from the Georgia PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations will continue to be reflected on the balance sheets as a regulatory liability. Therefore, the Company had no cumulative effect to net income resulting from the adoption of Statement No. 143 or FIN 47.

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. The fair value of assets legally restricted for settling retirement obligations related to nuclear facilities as of December 31, 2005 was $487 million. In addition, the Company has recognized retirement obligations related to various landfill sites, ash ponds, and underground storage tanks. The Company also recorded additional asset retirement obligations (and assets) of approximately $91 million related to asbestos removal. The Company has also identified retirement obligations related to certain transmission and distribution facilities, leasehold improvements, equipment on customer property, and property associated with the Company's rail lines. However, liabilities for the removal of these assets have not been 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 allowed removal costs in accordance with its regulatory treatment. Any difference between costs recognized under Statement No. 143 and FIN 47 and those reflected in rates are recognized as either a regulatory asset or liability in the balance sheets as ordered by the Georgia PSC. See "Nuclear Decommissioning" herein for further information on amounts included in rates.

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

	2005	2004
	(in millions)	
Balance beginning of year	**$505**	$476
Liabilities incurred	**91**	-
Liabilities settled	**(2)**	(2)
Accretion	**33**	31
Balance end of year	**$627**	$505

If FIN 47 had been adopted as of December 31, 2004, the pro forma asset retirement obligations would have been $591 million.

Nuclear Decommissioning

The Nuclear Regulatory Commission (NRC) requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has external trust funds to comply with the NRC's regulations. Use of the funds is restricted to nuclear decommissioning activities and the funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and state PSCs, as well as the Internal Revenue Service (IRS). The trust funds are invested in a tax-

efficient manner in a diversified mix of equity and fixed income securities and are classified as available-for-sale. The trust funds are included in the balance sheets at fair value, as obtained from quoted market prices for the same or similar investments. Details of the securities held in these trusts at December 31 are as follows:

2005	Unrealized Gains	Unrealized Losses	Fair Value
		(in millions)	
Equity	$76.7	$(6.3)	$325.5
Debt	2.8	(0.8)	135.3
Other	-	-	25.8
Total	**$79.5**	**$(7.1)**	**$486.6**

2004	Unrealized Gains	Unrealized Losses	Fair Value
		(in millions)	
Equity	$68.7	$(4.0)	$308.2
Debt	5.3	(0.1)	138.0
Other	-	-	13.0
Total	$74.0	$(4.1)	$459.2

The contractual maturities of debt securities at December 31, 2005 are as follows: $3.2 million in 2006; $34.9 million in 2007-2010; $32.4 million in 2011-2015; and $57.2 million thereafter.

Sales of the securities held in the trust funds resulted in proceeds of $372.5 million, $532.3 million, and $648.1 million in 2005, 2004, and 2003, respectively, all of which were re-invested. Net realized gains (losses) were $12.6 million, $14.1 million, and $21.3 million in 2005, 2004, and 2003, respectively. Realized gains and losses are determined on a specific identification basis. In accordance with regulatory guidance, all realized and unrealized gains and losses are included in the regulatory liability for Asset Retirement Obligations in the balance sheets and are not included in net income or other comprehensive income. Unrealized gains and losses are considered non-cash transactions for purposes of the statements of cash flow. Unrealized losses were not material in any period presented and do not represent any impairment of the underlying investments.

Amounts previously recorded in internal reserves are being transferred into the external trust funds over periods approved by the Georgia PSC. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed plans with the NRC to ensure that, over time -- the deposits and earnings of the external trust funds will provide the minimum funding amounts prescribed by the NRC. Annual provisions for nuclear decommissioning are based on an annuity method as approved by the Georgia PSC. The amount expensed in 2005 and fund balances were as follows:

	Plant Hatch	Plant Vogtle
	(in millions)	
Amount expensed in 2005	$ -	$ 7
Accumulated provisions:		
External trust funds, at fair value	$313	$174
Internal reserves	-	1
Total	$313	$175

Site study cost is the estimate to decommission a specific facility as of the site study year. The estimated costs of decommissioning based on the most current study performed in 2003 for the Company's ownership interests in plants Hatch and Vogtle were as follows:

	Plant Hatch	Plant Vogtle
Decommissioning periods:		
Beginning year	2034	2027
Completion year	2065	2048
	(in millions)	
Site study costs:		
Radiated structures	$497	$452
Non-radiated structures	49	58
Total	$546	$510

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

Under the 2001 Retail Rate Plan, the Georgia PSC approved the annual decommissioning costs for ratemaking of $9 million. This amount was based on the NRC generic estimate to decommission the radioactive

portion of the facilities as of 2000. The estimates were $383 million and $282 million for plants Hatch and Vogtle, respectively. Significant assumptions used to determine the costs for ratemaking included an estimated inflation rate of 4.7 percent and an estimated trust earnings rate of 6.5 percent.

Under the 2004 Retail Rate Plan, effective January 1, 2005, the Georgia PSC decreased the annual decommissioning costs for ratemaking to $7 million. This amount is based on the NRC generic estimate to decommission the radioactive portion of the facilities as of 2003. The estimates are $421 million and $326 million for plants Hatch and Vogtle, respectively. Significant assumptions used to determine the costs for ratemaking include an estimated inflation rate of 3.1 percent and an estimated trust earnings rate of 5.1 percent. Another significant assumption used was the change in the operating license for Plant Hatch. In January 2002, the NRC granted the Company a 20-year extension of the licenses for both units at Plant Hatch which permits the operation of units 1 and 2 until 2034 and 2038, respectively. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for the anticipated cost of decommissioning.

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

In accordance with regulatory treatment, the Company records AFUDC. AFUDC represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, it increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation expense. Interest related to the construction of new facilities not included in the Company's retail rates is capitalized in accordance with standard interest capitalization requirements. For the years 2005, 2004, and 2003, the average AFUDC rates were 8.02 percent, 8.22 percent, and 5.51 percent, respectively. AFUDC and interest capitalized, net of taxes, were 4.7 percent and 4.9 percent of net income after dividends on preferred stock for 2005 and 2004, respectively, and less than 3 percent for 2003.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment provision is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change. See Note 3 under "Retail Regulatory Matters" and "Plant McIntosh Construction Project" for information regarding a regulatory disallowance by the Georgia PSC in December 2004.

Storm Damage Reserve

The Company maintains a reserve for property damage to cover the cost of damages from major storms to its transmission and distribution lines and the cost of uninsured damages to its generation facilities and other property as mandated by the Georgia PSC. The Company accrues $6.3 million annually that is recoverable through base rates. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for storm damage costs.

Environmental Cost Recovery

Under Georgia PSC ratemaking provisions, $22 million has been deferred in a regulatory liability account related to certain environmental insurance settlements. Under the 2004 Retail Rate Plan, this regulatory liability is being amortized over a three-year period beginning January 1, 2005. However, the Georgia PSC also approved an annual environmental accrual of $5.4 million. Environmental remediation expenditures are charged against the reserve as they are incurred. The annual accrual amount will be reviewed and adjusted in future regulatory proceedings.

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 average costs 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.

Fuel Inventory

Fuel inventory includes the average costs of oil, coal, natural gas, and emission allowances. Fuel is charged to inventory when purchased and then expensed as used. Emission allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Stock Options

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

For pro forma purposes, the Company generally recognizes stock option expense on a straight-line basis over the vesting period. Stock options granted to employees who are eligible for retirement are expensed at the grant date.

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

Net Income	As Reported	Options Impact	Pro Forma
		(in millions)	
2005	**$715**	**$(3)**	**$712**
2004	$658	(3)	$655
2003	$631	(4)	$627

The estimated fair value of stock options granted in 2005, 2004, and 2003 was derived using the Black-Scholes stock option pricing model. The following table shows the assumptions and the weighted average fair values of stock options.

	2005	2004	2003
Interest rate	**3.90%**	3.10%	2.70%
Average expected life of stock options (in years)	**5.0**	5.0	4.3
Expected volatility of common stock	**17.90%**	19.60%	23.60%
Expected annual dividends on common stock	**$1.43**	$1.40	$1.37
Weighted average fair value of stock options granted	**$3.90**	$3.29	$3.59

See Note 8 for additional information.

Financial Instruments

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

through current period income and are recorded on a net basis in the statements of income.

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

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

	Carrying Amount	Fair Value
Long-term debt:	(in millions)	
2005	**$5,227**	**$5,195**
2004	$5,055	$5,125

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

Comprehensive Income

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

Variable Interest Entities

The primary beneficiary of a variable interest entity must consolidate the related assets and liabilities. The Company has established certain wholly-owned trusts to issue preferred securities. However, the Company is not the primary beneficiary of the trusts. Therefore, the investments in these trusts are reflected as Other Investments, and the related loans from the trusts are reflected as Long-Term Debt Payable to Affiliated Trusts on the balance sheets. See Note 6 under "Mandatorily Redeemable Preferred Securities/Long-Term Debt Payable to Affiliated Trusts" for additional information.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. The plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). In 2005, the plan was amended to provide an additional monthly supplement to certain retirees. No contributions to the plan are expected for the year ending December 31, 2006. The Company also provides certain non-qualified benefit plans for a selected group of management and highly compensated employees. Benefits under these non-qualified plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees. The Company funds related trusts to the extent required by the Georgia PSC and the FERC. For the year ended December 31, 2006, such contributions are expected to total approximately $18.4 million. The measurement date for plan assets and obligations is September 30 for each year presented.

Pension Plans

The accumulated benefit obligation for the pension plans was $1.9 billion in 2005 and $1.7 billion in 2004. Changes during the year in the projected benefit obligations, accumulated benefit obligations, and the fair value of plan assets was as follows:

	Projected Benefit Obligation	
	2005	2004
	(in millions)	
Balance at beginning of year	**$1,885**	$1,727
Service cost	**45**	42
Interest cost	**106**	101
Benefits paid	**(85)**	(85)
Plan amendments	**13**	1
Actuarial loss	**91**	99
Balance at end of year	**$2,055**	$1,885

	Plan Assets	
	2005	2004
	(in millions)	
Balance at beginning of year	**$2,181**	$2,055
Actual return on plan assets	**339**	207
Benefits paid	**(80)**	(81)
Balance at end of year	**$2,440**	$2,181

In 2005, the projected benefit obligations for the qualified and non-qualified pension plans were $1.945 billion and $110 million, respectively. All plan assets are related to the qualified plan.

Pension plan assets are managed and invested in accordance with all applicable requirements including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity, as described in the table below. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes.

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

	Plan Assets		
	Target	**2005**	2004
Domestic equity	36%	**40%**	36%
International equity	24	**24**	20
Fixed income	15	**17**	26
Real estate	15	**13**	10
Private equity	10	**6**	8
Total	100%	**100%**	100%

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

	2005	2004
	(in millions)	
Funded status	**$385**	$295
Unrecognized transition amount	**(4)**	(8)
Unrecognized prior service cost	**109**	108
Unrecognized net actuarial gain (loss)	**(54)**	21
Prepaid pension asset, net	**$436**	$416

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

	2005	2004
	(in millions)	
Prepaid pension asset	**$476**	$450
Employee benefit obligations	**(96)**	(89)
Other property and investments	**15**	19
Accumulated other comprehensive income	**41**	36
Prepaid pension asset, net	**$436**	$416

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

	2005	2004	2003
	(in millions)		
Service cost	**$ 45**	$ 42	$ 38
Interest cost	**106**	101	100
Expected return on plan assets	**(182)**	(180)	(179)
Recognized net (gain)/loss	**3**	(5)	(19)
Net amortization	**7**	7	6
Net pension (income)	**$(21)**	$(35)	$ (54)

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2005, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2006	$ 88
2007	91
2008	94
2009	97
2010	102
2011 to 2015	$607

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	
	2005	2004
	(in millions)	
Balance at beginning of year	**$726**	$723
Service cost	**10**	10
Interest cost	**41**	41
Benefits paid	**(32)**	(31)
Actuarial loss	**24**	42
Plan amendments	**-**	(59)
Balance at end of year	**$769**	$726

	Plan Assets	
	2005	2004
	(in millions)	
Balance at beginning of year	**$299**	$265
Actual return on plan assets	**38**	32
Employer contributions	**40**	33
Benefits paid	**(32)**	(31)
Balance at end of year	**$345**	$299

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

		Plan Assets	
	Target	**2005**	2004
Domestic equity	43%	**43%**	42%
International equity	21	**22**	23
Domestic fixed income	19	**19**	19
Global fixed income	11	**11**	11
Real estate	4	**3**	3
Private equity	2	**2**	2
Total	100%	**100%**	100%

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

	2005	2004
	(in millions)	
Funded status	**$(424)**	$(428)
Unrecognized transition obligation	**70**	78
Unrecognized prior service cost	**25**	27
Unrecognized net loss	**203**	203
Fourth quarter contributions	**21**	15
Employee benefit obligations recognized in the balance sheets	**$(105)**	$(105)

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

	2005	2004	2003
	(in millions)		
Service cost	**$10**	$ 10	$ 9
Interest cost	**41**	41	40
Expected return on plan assets	**(22)**	(25)	(24)
Net amortization	**18**	18	16
Net postretirement cost	**$47**	$ 44	$ 41

In the third quarter 2004, the Company prospectively adopted FASB Staff Position (FSP) 106-2, Accounting and Disclosure Requirements related to the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (Medicare Act). The Medicare Act provides a 28 percent prescription drug subsidy for Medicare eligible retirees. FSP 106-2 requires recognition of the impacts of the Medicare Act in the accumulated postretirement benefit obligation (APBO) and future cost of service for postretirement medical plans. The effect of the subsidy reduced the Company's expenses for the six months ended December 31, 2004 and for the year ended December 31, 2005 by approximately $5 million and $10 million, respectively, and is expected to have a similar impact on future expenses.

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the accumulated benefit obligation for the postretirement plans. Estimated benefit payments are reduced by drug

subsidy receipts expected as a result of the Medicare Act as follows:

	Benefit Payments	Subsidy Receipts	Total
	(in millions)		
2006	$ 37	$ (3)	$ 34
2007	39	(4)	35
2008	42	(4)	38
2009	46	(4)	42
2010	50	(5)	45
2011 to 2015	280	(34)	246

Actuarial Assumptions

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

	2005	2004	2003
Discount	**5.50%**	5.75%	6.00%
Annual salary increase	**3.00**	3.50	3.75
Long-term return on plan assets	**8.50**	8.50	8.50

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

An additional assumption used in measuring the APBO was a weighted average medical care cost trend rate of 10.25 percent for 2005, decreasing gradually to 4.75 percent through the year 2014, 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, 2005, as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$70	$62
Service and interest costs	5	4

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides a 75 percent matching contribution up to 6 percent of an employee's base salary. Total matching contributions made to the plan for the years 2005, 2004, and 2003 were $19 million, $18 million, and $18 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, and citizen enforcement of environmental requirements such as opacity and other air quality standards, 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 pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S District Court for the Northern District of Georgia against the Company and Alabama Power, alleging that the Company and Alabama Power had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws with respect to certain coal-fired generating facilities. Through subsequent amendments and other legal proceedings, the EPA added Savannah Electric as a defendant to the original action and filed a separate action against Alabama Power after it was dismissed from the original action. In these lawsuits, the

EPA alleges that NSR violations occurred at eight coal-fired generating facilities, including the Company's Plants Bowen and Scherer. The civil action requests penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. On June 3, 2005, the U.S. District for the Northern District of Alabama issued a decision in favor of Alabama Power on two primary legal issues in the case; however, the decision does not resolve the case, nor does it address other legal issues associated with the EPA's allegations. In accordance with a separate court order, Alabama Power and the EPA are currently participating in mediation with respect to the EPA's claims. The action against the Company and Savannah Electric has been administratively closed since the spring of 2001, and none of the parties has sought to reopen the case.

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $32,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in this case could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

Plant Wansley Environmental Litigation

In December 2002, the Sierra Club, Physicians for Social Responsibility, Georgia Forestwatch, and one individual filed a civil suit in the U.S. District Court for the Northern District of Georgia against the Company for alleged violations of the Clean Air Act at four of the units at Plant Wansley. 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. The liability phase of the case has concluded with the court ruling in favor of the Company in part and the plaintiffs in part. In March 2005, the U.S. Court of Appeals for the Eleventh Circuit accepted the Company's petition for review of the district court's order, and oral arguments were held on January 24, 2006. The district court case has been administratively closed pending that appeal. If necessary, the district court will hold a separate trial which will address civil penalties and possible injunctive relief requested by the plaintiffs. The ultimate outcome of this matter cannot currently be determined; however, an adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

Environmental Remediation

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. In 1995, the EPA designated the Company and four other unrelated entities as potentially responsible parties at a site in Brunswick, Georgia that is listed on the federal National Priorities List. As of December 31, 2005, the Company had recorded approximately $6 million in cumulative expenses associated with the Company's agreed-upon share of the removal and remedial investigation and feasibility study costs for the Brunswick site. Additional claims for recovery of natural resource damages at the site are anticipated. The Company has also recognized $36 million in cumulative expenses through December 31, 2005 for the assessment and anticipated cleanup of sites on the Georgia Hazardous Sites Inventory.

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 the Company'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.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates at market-based prices. The Company also has FERC authority to make short-term opportunity sales at market rates. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in that proceeding. In February 2005, Southern Company submitted responsive information. In February 2006, the FERC agreed to allow the parties to conduct settlement discussions. Any new market-based rate transactions in its retail service territory entered into after February 27, 2005 are subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. The impact of such sales through December 31, 2005 is not expected to exceed $4.9 million. The refund period covers 15 months. In the event that the FERC's default mitigation measures for entities that are found to have market power are ultimately applied, the Company may be required to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates. The final outcome of this matter will depend on the form in which the final methodology for assessing generation market power and mitigation rules may be ultimately adopted and cannot be determined at this time.

In addition, in May 2005, the FERC started an investigation to determine whether Southern Company satisfies the other three parts of the FERC's market-based rate analysis: transmission market power, barriers to entry, and affiliate abuse or reciprocal dealing. The FERC established a new refund period related to this expanded investigation. Any and all new market-based rate transactions both inside and outside Southern Company's retail service territory involving any Southern Company subsidiary, including the Company, will be subject to refund to the extent the FERC orders lower rates as a result of this new investigation, with the 15-month refund period beginning July 19, 2005. The impact of such sales through December 31, 2005 is not expected to exceed $10.9 million, of which $3.2 million relates to sales inside the retail service territory as discussed above. The FERC also directed that this expanded proceeding be held in abeyance pending the outcome of the proceeding on the IIC discussed below.

The Company believes that there is no meritorious basis for this proceeding and is vigorously defending itself in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in this proceeding, cannot now be determined.

Intercompany Interchange Contract

The Company's generation fleet in its retail service territory is operated under the IIC, as approved by the FERC. In May 2005, the FERC also initiated a new proceeding to examine (1) the provisions of the IIC among Alabama Power, the Company, Gulf Power, Mississippi Power, Savannah Electric, Southern Power, and SCS, as agent, under the terms of which the power pool of Southern Company is operated, and, in particular, the propriety of the continued inclusion of Southern Power as a party to the IIC, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining Southern Power as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of Southern Power, the FERC authorized Southern Power's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct. The FERC order directs that the administrative law judge who presided over the McIntosh PPA proceeding involving an approval of PPAs between Southern Power and the Company and Savannah Electric, be assigned to preside over the hearing in this proceeding and that the testimony and exhibits presented in that proceeding be preserved to the extent appropriate. Hearings are scheduled for September 2006. Effective July 19, 2005, revenues from transactions under the IIC involving any Southern Company subsidiaries, including the Company, are subject to refund to the extent the FERC orders any changes to the IIC.

The Company believes that there is no meritorious basis for this proceeding and is vigorously defending itself in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in this proceeding, cannot now be determined.

Generation Interconnection Agreements

In July 2003, the FERC issued its final rule on the standardization of generation interconnection agreements and procedures (Order 2003). Order 2003 shifts much of the financial burden of new transmission investment from the generator to the transmission provider. The FERC has indicated that Order 2003, which was effective January 20, 2004, is to be applied prospectively to interconnection

agreements. Subsidiaries of Tenaska, Inc., as counterparties to previously executed interconnection agreements with the Company and another Southern Company subsidiary, have filed complaints at the FERC requesting that the FERC modify the agreements and that the Company refund a total of $7.9 million previously paid for interconnection facilities, with interest. The Company has opposed such relief and the proceedings are still pending. The impact of Order 2003 and its subsequent rehearings on the Company and the final results of these matters cannot be determined at this time.

Race Discrimination Litigation

In July 2000, a lawsuit alleging race discrimination was filed by three of the Company's employees against the Company, Southern Company, and SCS in the Superior Court of Fulton County, Georgia. Shortly thereafter, the lawsuit was removed to the U.S. District Court for the Northern District of Georgia and amended to add four more plaintiffs. The lawsuit also raised claims on behalf of a purported class. The plaintiffs sought compensatory and punitive damages in an unspecified amount, as well as injunctive relief.

Following various court decisions in favor of the defendants and subsequent appeals by the plaintiffs, on July 13, 2005, the plaintiffs filed a petition for writ of certiorari to the U.S. Supreme Court. On October 17, 2005, the petition was denied. This matter is now concluded.

Right of Way Litigation

Southern Company and certain of its subsidiaries, including the Company, Gulf Power, Mississippi Power, and Southern Telecom, have been named as defendants in numerous lawsuits brought by landowners since 2001. 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 exceed the easements or other property rights held by defendants. The plaintiffs assert claims for, among other things, trespass and unjust enrichment, and seek compensatory and punitive damages and injunctive relief. Management believes that the Company has complied with applicable laws and that the plaintiffs' claims are without merit.

In January 2005, the Superior Court of Decatur County, Georgia granted partial summary judgment in a lawsuit brought by landowners against the Company based on the plaintiffs' declaratory judgment claim that the easements do not permit general telecommunications use. The Company appealed this ruling to the Georgia Court of Appeals. The Georgia Court of Appeals reversed, in part, the court's order and remanded the case to the trial court for the determination of further issues. After the Court of Appeals' decision, the plaintiffs filed a motion for reconsideration, which was denied, and a petition for certiorari to the Georgia Supreme Court, which is currently pending. The question of damages and other liabilities or remedies issues with respect to this action, if any, will be decided at a future trial. In the event of an adverse verdict in the case, the Company could appeal both liability and damages or other relief granted. An adverse outcome in these matters could result in substantial judgments; however, the final outcome cannot now be determined.

In addition, in late 2001, certain subsidiaries of Southern Company, including Alabama Power, the Company, Gulf Power, Mississippi Power, Savannah Electric, and Southern Telecom, were named as defendants in a lawsuit brought by a telecommunications company that uses certain of the defendants' rights of way. This lawsuit alleges, among other things, that the defendants are contractually obligated to indemnify, defend, and hold harmless the telecommunications company from any liability that may be assessed against it in pending and future right of way litigation. The Company believes that the plaintiff's claims are without merit. In the fall of 2004, the trial court stayed the case until resolution of the underlying landowner litigation discussed above. In January 2005, the Georgia Court of Appeals dismissed the telecommunications company's appeal of the trial court's order for lack of jurisdiction. An adverse outcome in this matter, combined with an adverse outcome against the telecommunications company in one or more of the right of way lawsuits, could result in substantial judgments; however, the final outcome of these matters cannot now be determined.

Property Tax Dispute

The Company is involved in a significant property tax dispute with Monroe County, Georgia (Monroe County). The Monroe County Board of Tax Assessors (Monroe Board) has issued assessments reflecting substantial

increases in the ad valorem tax valuation of the Company's 22.95 percent ownership interest in Plant Scherer, which is located in Monroe County, for tax years 2003, 2004, and 2005. The Company is aggressively pursuing administrative appeals in Monroe County and has filed notices of arbitration for all three years. The appeals are currently stayed, pending the outcome of the litigation discussed below.

In November 2004, the Company filed suit, on its behalf, against the Monroe Board in the Superior Court of Monroe County. The Company contends that Monroe County acted without statutory authority in changing the valuation of a centrally assessed utility as established by the Revenue Commissioner of the State of Georgia and requests injunctive relief prohibiting Monroe County and the Monroe Board from unlawfully changing the value of Plant Scherer and ultimately collecting additional ad valorem taxes from the Company. On December 22, 2005, the court granted Monroe County's motion for summary judgment. The Company has filed an appeal of the Superior Court's decision to the Georgia Supreme Court.

If the Company is not successful in its administrative appeals and if Monroe County is successful in defending the litigation, the Company could be subject to total additional taxes through December 31, 2005 of up to $13 million, plus penalties and interest. The ultimate outcome of this matter cannot currently be determined.

Retail Regulatory Matters

Merger

On December 13, 2005, the Company and Savannah Electric entered into an Agreement and Plan of Merger. Savannah Electric will merge into the Company, with the Company continuing as the surviving corporation (the Merger). At the effective time of the Merger, each share of the Company's common stock will remain issued and outstanding; each share of the Company's preferred stock issued and outstanding will have been redeemed prior to the Merger; the issued and outstanding shares of Savannah Electric common stock, all of which are held by Southern Company, will be converted into the right to receive 1,500,000 shares of the Company's common stock; and each share of Savannah Electric preferred stock issued and outstanding immediately prior to the Merger will be converted into the right to receive one share of a new series of the Company's Class A Preferred Stock. The Merger must be approved by the preferred shareholders of Savannah Electric and is subject to the receipt of certain regulatory approvals from the FERC, the Georgia PSC, and the Federal Communications Commission. Pending regulatory approvals, the Merger is expected to be completed by July 2006. The Merger is not expected to have a material impact on the Company's financial statements.

While the Georgia PSC does not have specific approval authority over the merger of electric utilities, the Company and Savannah Electric have filed an application with the Georgia PSC with respect to certain approvals that will be necessary to effectively complete the Merger. In particular, the Company and Savannah Electric plan to seek the approval of the Georgia PSC with respect to the following matters:

- the transfer of Savannah Electric's generating facilities and certification of the generating facilities as the Company's assets;
- amendments to the Company's Integrated Resource Plan to add the current Savannah Electric's customers and generating facilities;
- the transfer of Savannah Electric's assigned service territory to the Company;
- adoption of the Company's service rules and regulations to the current Savannah Electric customers;
- new fuel rate and base rate schedules that would apply to the Company's sale of electricity to the current Savannah Electric customers;
- adoption of a "merger transition adjustment" rate that would be used to more closely align Savannah Electric's existing base rates to those of the Company and a "merger transition credit" rate that would credit the additional revenues collected from former Savannah Electric customers to the Company's existing customers; and
- the issuance of additional shares of the Company's common stock to Southern Company in exchange for Southern Company's shares of Savannah Electric common stock.

Rate Plans

Under the terms of the 2004 Retail Rate Plan, which the Georgia PSC approved in December 2004, the Company's earnings are evaluated against a retail return on common equity (ROE) range of 10.25 percent to 12.25 percent. Two-thirds of any earnings

above 12.25 percent will be applied to rate refunds, with the remaining one-third retained by the Company. Retail rates were increased by approximately $194 million and customer fees by approximately $9 million effective January 1, 2005 to cover the higher costs of purchased power; operating and maintenance expenses; environmental compliance; and continued investment in new generation, transmission, and distribution facilities to support growth and ensure reliability. In 2005, the Company recorded $2.7 million in revenue subject to refund related to earnings in excess of 12.25 percent retail ROE.

The Company is required to file a general rate case by July 1, 2007, in response to which the Georgia PSC would be expected to determine whether the rate order should be continued, modified, or discontinued. Until then, the Company may not file for a general base rate increase unless its projected retail ROE falls below 10.25 percent.

Under the 2001 Retail Rate Plan, retail rates were decreased by $118 million effective January 1, 2002. Under the terms of the 2001 Retail Rate Plan, earnings were evaluated against a retail ROE range of 10 percent to 12.95 percent. Two-thirds of any earnings above the 12.95 percent return were to be applied to rate refunds, with the remaining one-third retained by the Company. The Company's earnings in 2004, 2003, and 2002 were within the retail ROE range.

Under the 2001 Retail Rate Plan, the Company discontinued recording accelerated depreciation and amortization and began amortizing the accumulated balance equally over three years as a credit to expense beginning in 2002. Also, the 2001 Retail Rate Plan required the Company to recognize capacity and operating and maintenance costs related to new Georgia PSC-certified PPAs evenly in rates over a three-year period ended December 31, 2004.

Fuel Hedging Program

In 2003, the Georgia PSC approved an order allowing the Company to implement a natural gas and oil procurement and hedging program. This order allows the Company to use financial instruments to hedge price and commodity risk associated with these fuels. 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 the Company retaining 25 percent of the total net gains. In 2005, the Company had a total net gain of $64.1 million, of which the Company retained $16 million.

Fuel Cost Recovery

On May 17, 2005, the Georgia PSC approved the Company's request to increase customer fuel rates by approximately 9.5 percent to recover under recovered fuel costs of approximately $508 million existing as of May 31, 2005 over a four-year period that began June 1, 2005. Based on the order, a portion of the under recovered regulatory clause revenues was reclassified from current assets to deferred charges and other assets in the balance sheet. Under recovered fuel amounts for the periods subsequent to June 1, 2005 totaled $327.5 million through December 31, 2005. The Georgia PSC's order instructs that such amounts be reviewed semi-annually beginning February 2006. If the amount under or over recovered exceeds $50 million at the evaluation date, the Company would be required to file for a temporary fuel rate change. In addition, Savannah Electric's under recovered fuel costs totaled $77.7 million at December 31, 2005. In accordance with the Georgia PSC order, Savannah Electric was scheduled to file an additional request for a fuel cost recovery increase in January 2006. The Company has agreed with a Georgia PSC staff recommendation to forego the temporary fuel rate process, and Savannah Electric has postponed its scheduled filing. Instead, the Company and Savannah Electric will file a combined request in March 2006 to increase the Company's fuel cost recovery rate.

The case will seek approval of a fuel cost recovery rate based upon future fuel cost projections for the combined Company and Savannah Electric generating fleet as well as the under recovered fuel balances existing at June 30, 2006. The new fuel cost recovery rate would be billed beginning in July 2006 to all of the Company's customers, including the existing Savannah Electric customers. Under recovered amounts as of the date of the Merger will be paid by the appropriate customer groups.

In August 2005, the Georgia PSC initiated an investigation of Savannah Electric's fuel practices. In February 2006, an investigation of the Company's fuel

practices was initiated. The Company and Savannah Electric are responding to data requests and cooperating in the investigations. The final outcome of this matter cannot now be determined.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable cost and amounts billed in current regulated rates. Accordingly, any increase in the billing factor would have no significant effect on the Company's revenues or net income, but would increase annual cash flow.

Nuclear Performance Standards

Through December 2004, the Georgia PSC had adopted a three-year performance standard for the Company's nuclear generating units. The performance standard was 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. For the period 2002-2004, the Company's performance fell within the criteria prescribed by the Georgia PSC; there was no associated award or penalty. Effective January 1, 2005, the Georgia PSC discontinued the nuclear performance standard.

Plant McIntosh Construction Project

In December 2002 after a competitive bidding process, the Georgia PSC certified PPAs between Southern Power and the Company and Savannah Electric for capacity from Plant McIntosh Units 10 and 11, construction of which was completed in June 2005. In April 2003, Southern Power applied for FERC approval of these PPAs. In July 2003, the FERC accepted the PPAs to become effective June 1, 2005, subject to refund, and ordered that hearings be held. Intervenors opposed the FERC's acceptance of the PPAs, alleging that they did not meet the applicable standards for market-based rates between affiliates. To ensure the timely completion of the Plant McIntosh construction project and the availability of the units in the summer of 2005 for their retail customers, in May 2004, the Company and Savannah Electric requested the Georgia PSC to direct them to acquire the Plant McIntosh construction project. The Georgia PSC issued such an order and the transfer occurred on May 24, 2004 at a total cost of approximately $415 million, including approximately $14 million of transmission interconnection facilities. Subsequently, Southern Power filed a request to withdraw the PPAs and to terminate the ongoing FERC proceedings. In August 2004, the FERC issued a notice accepting the request to withdraw the PPAs and permitting such request to become effective by operation of law. However, the FERC made no determination on what additional steps may need to be taken with respect to testimony provided in the proceedings. See "FERC Matters – Intercompany Interchange Contract" herein for additional information.

In connection with the 2004 Retail Rate Plan, the Georgia PSC approved the transfer of the Plant McIntosh construction project at a total fair market value of approximately $385 million. This value reflected an approximate $16 million disallowance, of which $13 million was attributable to the Company, and reduced the Company's net income by approximately $8 million. The Georgia PSC also certified a total completion cost not to exceed $547 million for the project. In June 2005, Plant McIntosh Units 10 and 11 were placed into service at a total cost that did not exceed the certified amount. Under the 2004 Retail Rate Plan, the Plant McIntosh revenue requirements impact is being reflected in the Company's rates evenly over the three years ending 2007. See "Retail Regulatory Matters—Rate Plans" herein for additional information regarding the transfer of the Plant McIntosh construction project.

4. JOINT OWNERSHIP AGREEMENTS

The Company and an affiliate, Alabama Power, own equally all of the outstanding capital stock of SEGCO which owns electric generating units with a total rated capacity of 1,020 megawatts, as well as associated transmission facilities. The capacity of 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:

	2005	2004	2003
		(in millions)	
Energy	$54	$51	$55
Capacity	38	36	34
Total	$92	$87	$89

The Company 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 (MEAG), the city of Dalton, Georgia, Florida Power & Light Company, Jacksonville Electric Authority, and Gulf Power. Under these agreements, the Company has contracted to operate and maintain the plants as agent for the co-owners and 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 combustion- turbine common facilities and Plant McIntosh combined cycle units with Savannah Electric who operates the plants. The Company and Progress Energy Florida, Inc. jointly own a combustion turbine unit (Intercession City) operated by Progress Energy Florida, Inc.

At December 31, 2005, 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%	$3,311*	$1,809
Plant Hatch (nuclear)	50.1	935	492
Plant Wansley (coal)	53.5	395	172
Plant Scherer (coal)			
Units 1 and 2	8.4	115	56
Unit 3	75.0	562	270
Plant McIntosh CC (combined cycle)	83.9	436	7
Plant McIntosh Common Facilities (combustion-turbine)	75.0	27	5
Rocky Mountain (pumped storage)	25.4	169*	92
Intercession City (combustion-turbine)	33.3	12	2

*Investment includes write-offs

At December 31, 2005, the portion of total construction work in progress related to Plants Wansley, Scherer, and Rocky Mountain was $8.3 million, $0.5 million, and $0.1 million, respectively, primarily for environmental projects.

The Company's proportionate share of its plant operating expenses is included in the corresponding operating expenses in the statements of income.

5. INCOME TAXES

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

In 2004, in order to avoid the loss of certain federal income tax credits related to the production of synthetic fuel, Southern Company chose to defer certain

deductions otherwise available to the subsidiaries. The cash flow benefit associated with the utilization of the tax credits was allocated to the subsidiary that otherwise would have claimed the available deductions on a separate company basis without the deferral. This allocation concurrently reduced the tax benefit of the credits allocated to those subsidiaries that generated the credits. As the deferred expenses are deducted, the benefit of the tax credits will be repaid to the subsidiaries that generated the tax credits. The Company has recorded $10 million payable to these subsidiaries in Accumulated Deferred Income Taxes on the balance sheets at December 31, 2005.

The transfer of the Plant McIntosh construction project from Southern Power to the Company resulted in a deferred gain to Southern Power for federal income tax purposes. The Company will reimburse Southern Power for the remaining balance of the related deferred taxes of $5.3 million reflected in Southern Power's future taxable income. $3.7 million of this payable to Southern Power is included in Other Deferred Credits and $1.6 million is included in Affiliated Accounts Payable in the balance sheet at December 31, 2005.

The transfer of the Dahlberg, Wansley, and Franklin projects to Southern Power from the Company in 2001 and 2002 also resulted in a deferred gain for federal income tax purposes. Southern Power will reimburse the Company for the remaining balance of the related deferred taxes of $12.2 million reflected in the Company's future taxable income. $10.8 million of this receivable from Southern Power is included in Other Deferred Debits and $1.4 million is included in Affiliated Accounts Receivable in the balance sheet at December 31, 2005.

At December 31, 2005, tax-related regulatory assets were $501 million and tax-related regulatory liabilities were $159 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:

	2005	2004	2003
Total provision for income taxes:		(in millions)	
Federal:			
Current	**$173**	$116	$143
Deferred	**203**	221	181
	376	337	324
State:			
Current	**26**	12	24
Deferred	**29**	30	16
Deferred investment tax credits	**-**	-	2
Total	**$431**	$379	$366

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:

	2005	2004
	(in millions)	
Deferred tax liabilities:		
Accelerated depreciation	**$2,177**	$2,050
Property basis differences	**558**	577
Employee benefit obligations	**163**	149
Fuel clause under recovery	**305**	141
Premium on reacquired debt	**69**	72
Storm damage reserve	**13**	6
Other	**74**	81
Total	**3,359**	3,076
Deferred tax assets:		
Federal effect of state deferred taxes	**116**	106
Other property basis differences	**139**	147
Other deferred costs	**126**	94
Employee benefit obligations	**51**	55
Other comprehensive income	**23**	22
Unbilled revenue	**13**	11
Other	**33**	19
Total	**501**	454
Total deferred tax liabilities, net	**2,858**	2,622
Portion included in current (liabilities) assets, net	**(128)**	(66)
Accumulated deferred income taxes in the balance sheets	**$2,730**	$2,556

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 2005, $12 million in 2004, and $15 million in 2003. At December 31, 2005, all investment tax credits available to reduce federal income taxes payable had been utilized.

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

	2005	2004	2003
Federal statutory rate	35%	35%	35%
State income tax, net of federal deduction	3	3	3
Non-deductible book depreciation	1	1	1
Other	(1)	(2)	(2)
Effective income tax rate	38%	37%	37%

6. FINANCING

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

The Company has formed certain wholly owned trust subsidiaries for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the Company through the issuance of junior subordinated notes totaling $969 million, which constitute substantially all of the assets of the trusts and are reflected in the balance sheets as Long-Term Debt Payable to Affiliated Trusts. The Company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the respective trusts' payment obligations with respect to these securities. At December 31, 2005, preferred securities of $940 million were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for these trusts and the related securities.

Securities Due Within One Year

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

	2005	2004
	(in millions)	
Capital lease	$ 3	$ 2
Senior notes	150	450
Preferred stock	15	-
Total	$168	$452

Serial maturities through 2010 applicable to total long-term debt and preferred stock are as follows: $168 million in 2006; $303 million in 2007; $3 million in 2008; $278 million in 2009; and $4 million in 2010.

Pollution Control Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such 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, 2005 was $1.7 billion.

Senior Notes

The Company issued a total of $625 million of unsecured senior notes in 2005. The proceeds of these issues were used to redeem or repay at maturity long-term debt, to repay short-term indebtedness, and for other general corporate purposes. At December 31, 2005 and 2004, the Company had $2.6 billion and $2.4 billion of senior notes outstanding, respectively. These senior notes are subordinate to all secured debt of the Company.

Capital Leases

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, 2005 and 2004, the Company had a capitalized lease obligation for its corporate headquarters

building of $74 million and $77 million, respectively, with an interest rate of 8.1 percent. For ratemaking purposes, the Georgia PSC 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 Georgia PSC. See Note 1 under "Regulatory Assets and Liabilities."

Bank Credit Arrangements

At the beginning of 2006, the Company had credit arrangements with banks totaling $780 million, of which $778 million was unused. Of these facilities, $70 million expires at various times throughout 2006; $350 million expires in 2007, with the remaining $360 million expiring in 2010. The facilities that expire in 2006 provide the option of converting borrowings into a two-year term loan. The Company expects to renew its facilities, as needed, prior to expiration. The agreements contain stated borrowing rates. All the agreements require payment of commitment fees based on the unused portion 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. A fee is also paid to the agent bank.

The credit arrangements contain covenants that limit the level of indebtedness to capitalization to 65 percent, as defined in the arrangements. For purposes of these definitions, indebtedness excludes the long-term debt payable to affiliated trusts. In addition, the credit arrangements contain cross default provisions that would trigger an event of default if the Company defaulted on other indebtedness above a specified threshold. At December 31, 2005, the Company was in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowings.

The $778 million 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, 2005 was $106 million. In addition, the Company borrows under a commercial paper program and an extendible commercial note program. The amount of commercial paper outstanding at December 31, 2005 was $268 million. The amount of commercial paper outstanding at December 31, 2004 was $208 million. There were no outstanding extendible commercial notes at December 31, 2005. Commercial paper is included in notes payable on the balance sheets.

During 2005, the peak amount of short-term debt outstanding was $549 million and the average amount outstanding was $242 million. The average annual interest rate on short-term debt in 2005 was 3.20 percent.

Financial Instruments

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. See Note 3 under "Retail Regulatory Matters – Fuel Hedging Program" for information on the Company's fuel hedging program. The Company also enters into hedges of forward electricity sales. There was no material ineffectiveness recorded in earnings in 2005, 2004, and 2003.

At December 31, 2005, the fair value of derivative energy contracts was reflected in the financial statements as follows:

	Amounts (in thousands)
Regulatory liabilities, net	$26,643
Other comprehensive income	-
Net income	(81)
Total fair value	$26,562

The fair value gain or loss for hedges that are recoverable through the regulatory fuel clauses are recorded in regulatory assets and liabilities and are recognized in earnings at the same time the hedged items affect earnings. The Company has energy-related hedges in place up to and including 2008.

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

addition to interest rate swaps, the Company has also entered into certain options agreements that effectively cap its interest rate exposure in return for payment of a premium. In some cases, costless collars have been used that effectively establish a floor and a ceiling to interest rate expense.

At December 31, 2005, the Company had $1.0 billion notional amounts of interest derivatives accounted for as cash flow hedges outstanding with net fair value gains as follows:

Maturity	Weighted Average Fixed Rate Paid	Notional Amount	Fair Value Gain / (Loss)
		(in millions)	
2007	2.67%	$300	$ 2.4
2006-2007	2.09% -3.85%*	$400	$ 1.2
2037	4.58% -5.75%**	$300	$(1.1)

*Series of interest rate caps and collars (showing the lowest floor and highest cap) with variable rate based on one-month LIBOR
**Interest rate collar

The fair value gain or loss for cash flow hedges is recorded in other comprehensive income and is reclassified into earnings at the same time the hedged items affect earnings. In 2005, 2004, and 2003, the Company settled gains (losses) totaling $0.9 million, $(12.4) million, and $(11.3) million, respectively, upon termination of certain interest derivatives at the same time it issued debt. For the years 2005, 2004, and 2003, approximately $1.9 million, $3.9 million, and $3.4 million, respectively, of pre-tax losses were reclassified from other comprehensive income to interest expense. For 2006, pre-tax losses of approximately $0.5 million are expected to be reclassified from other comprehensive income to interest expense. The Company has gains/losses that are being amortized through 2017.

7. COMMITMENTS

Construction Program

The Company currently estimates property additions to be approximately $1.3 billion, $1.4 billion, and $1.3 billion in 2006, 2007, and 2008, respectively. These amounts include $44 million, $28 million, and $14 million in 2006, 2007, and 2008, respectively, for construction expenditures related to contractual purchase commitments for uranium and nuclear fuel conversion, enrichment, and fabrication services included under "Fuel Commitments" herein. 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, changes in FERC rules and transmission regulations, 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, 2005, significant purchase commitments were outstanding in connection with the construction program.

The Company completed construction of Plant McIntosh Units 10 and 11 in June 2005 and has no other generating plants currently under construction. Construction related to new transmission and distribution facilities and capital improvements to existing generation, transmission and distribution facilities, including those needed to meet environmental standards, is ongoing.

Long-Term Service Agreements

The Company and Savannah Electric have entered into a Long-Term Service Agreement (LTSA) with General Electric (GE) for the purpose of securing maintenance support for the combustion turbines at the Plant McIntosh combined cycle facility. In summary, the LTSA stipulates that GE will perform all planned inspections on the covered equipment, which includes the cost of all labor and materials. GE is also obligated to cover the costs of unplanned maintenance on the covered equipment subject to a limit specified in each contract.

In general, this LTSA is in effect through two major inspection cycles per unit. Scheduled payments to GE are made at various intervals based on actual operating hours of the respective units. Total payments to GE under this agreement are currently estimated at $186 million over the remaining term of the agreement, which may range up to 30 years. However, the LTSA contains various cancellation provisions at the option of the Company.

The Company has also entered into an LTSA with GE through 2014 for neutron monitoring system parts and electronics at Plant Hatch. Total remaining payments to GE under this agreement are currently estimated at $13.1 million. The contract contains

cancellation provisions at the option of the Company.

Payments made to GE prior to the performance of any work are recorded as a prepayment in the balance sheets. Work performed by GE is capitalized or charged to expense as appropriate net of any joint owner billings, based on the nature of the work.

Fuel Commitments

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement of fossil and nuclear fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Coal commitments include forward contract purchases for sulfur dioxide emission allowances. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery. Amounts included in the chart below represent estimates based on New York Mercantile Exchange future prices at December 31, 2005.

Total estimated minimum long-term obligations at December 31, 2005 were as follows:

	Commitments		
	Natural Gas	Coal	Nuclear Fuel
		(in millions)	
2006	$577	$1,579	$ 44
2007	325	1,313	28
2008	200	907	14
2009	257	422	11
2010	254	272	14
2011 and thereafter	2,047	40	64
Total	$3,660	$4,533	$175

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

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other Southern Company retail operating companies, Southern Power, and Southern Company Gas. Under these agreements, each of the retail operating companies, Southern Power, and Southern Company Gas may be jointly and severally liable. The creditworthiness of Southern Power and Southern Company Gas is currently inferior to the creditworthiness of the retail operating companies. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the retail 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 Company Gas as a contracting party under these agreements.

Purchased Power Commitments

The Company has commitments regarding a portion of a 5 percent interest in Plant Vogtle owned by 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 $54 million, $55 million, and $57 million in 2005, 2004, and 2003, respectively. The current projected Plant Vogtle capacity payments are:

	Capacity Payments
	(in millions)
2006	$ 53
2007	52
2008	54
2009	54
2010	54
2011 and thereafter	261
Total	$528

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 at the time of the disallowance was written off.

The Company has entered into other various long-term commitments for the purchase of electricity. Estimated total long-term obligations under these

commitments at December 31, 2005 were as follows:

	Commitments	
	Affiliated	Non-Affiliated
	(in millions)	
2006	$205	$85
2007	205	86
2008	205	87
2009	205	68
2010	112	66
2011 and thereafter	455	278
Total	$1,387	$670

Operating Leases

The Company has entered into various operating leases with various terms and expiration dates. Rental expenses related to these operating leases totaled $38 million for 2005, $38 million for 2004, and $36 million for 2003.

At December 31, 2005, estimated minimum lease payments for these noncancelable operating leases were as follows:

	Minimum Lease Payments		
	Rail Cars	Other	Total
		(in millions)	
2006	$ 17	$ 17	$ 34
2007	17	14	31
2008	16	11	27
2009	15	9	24
2010	14	6	20
2011 and thereafter	48	10	58
Total	$127	$67	$194

In addition to the rental commitments above, the Company has obligations upon expiration of certain rail car leases with respect to the residual value of the leased property. These leases expire in 2011 and the Company's maximum obligation is $68 million. 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 rail car lease obligations is shared with the joint owners of plants Scherer and Wansley. Rental expenses related to the rail car leases are fully recoverable through the fuel cost recovery clause as ordered by the Georgia PSC.

Guarantees

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. Alabama Power has also guaranteed $50 million in senior notes issued by SEGCO. The Company has agreed to reimburse Alabama Power for the pro rata portion of such obligations corresponding to the Company'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.

8. STOCK OPTION PLAN

Southern Company provides non-qualified stock options to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2005, 1,551 current and former employees of the Company participated in the stock option plan. The maximum number of shares of Southern Company common stock that may be issued under this plan may not exceed 55 million. The prices of options granted to date have been at the fair market value of the shares on the dates of grant. Options granted to date become exercisable pro rata over a maximum period of three years from the date of grant. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the stock option plan. Activity from 2003 to 2005 for the options granted

to the Company's employees under the stock option plan is summarized below:

	Shares Subject To Option	Average Option Price Per Share
Balance at December 31, 2002	7,178,597	$19.73
Options granted	1,455,517	27.98
Options canceled	(54,860)	25.47
Options exercised	(1,428,273)	16.92
Balance at December 31, 2003	7,150,981	21.92
Options granted	1,434,915	29.50
Options canceled	(6,371)	25.99
Options exercised	(1,450,309)	18.25
Balance at December 31, 2004	**7,129,216**	**24.19**
Options granted	**1,427,618**	**32.71**
Options canceled	**(12,910)**	**23.75**
Options exercised	**(1,838,033)**	**21.23**
Balance at December 31, 2005	**6,705,891**	**$26.82**

Options exercisable:	
At December 31, 2003	3,956,234
At December 31, 2004	4,304,091
At December 31, 2005	**3,989,722**

The following table summarizes information about options outstanding at December 31, 2005:

	Dollar Price Range of Options		
	13-21	21-28	28-35
Outstanding:			
Shares (in thousands)	991	2,922	2,794
Average remaining life (in years)	4.2	6.0	8.5
Average exercise price	$17.25	$25.94	$31.13
Exercisable:			
Shares (in thousands)	991	2,496	503
Average exercise price	$17.25	$25.59	$29.75

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act, the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the Company's nuclear power plants. The Act provides funds up to $10.76 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 $101 million per incident for each licensed reactor it operates but not more than an aggregate of $15 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 $203 million per incident but not more than an aggregate of $30 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 up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. The Company purchases the maximum limit allowed by NEIL 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 NEIL policies would be $48 million.

Following the terrorist attacks of September 2001, both ANI and NEIL confirmed that terrorist acts against commercial nuclear power plants would, subject to the normal policy limits, be covered under their insurance. Both companies, however, revised their policy terms on

a prospective basis to include an industry aggregate for all "non-certified" terrorist acts i.e., acts that are not certified acts of terrorism pursuant to the Terrorism Risk Insurance Act of 2002, which was renewed in 2005. The aggregate for all NEIL policies, which applies to non-certified property claims stemming from terrorism within a 12-month duration, is $3.24 billion plus any amounts available through reinsurance or indemnity from an outside source. The non-certified ANI nuclear liability cap is a $300 million shared industry aggregate during the normal ANI policy period.

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

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

10. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2005 and 2004 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred Stock
		(in millions)	
March 2005	**$1,370**	**$286**	**$142**
June 2005	**1,459**	**311**	**158**
September 2005	**2,219**	**626**	**355**
December 2005	**1,586**	**165**	**60**
March 2004	$1,199	$285	$144
June 2004	1,353	322	156
September 2004	1,582	486	287
December 2004	1,237	166	71

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

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SELECTED FINANCIAL AND OPERATING DATA 2001-2005

Georgia Power Company 2005 Annual Report

	2005	2004	2003	2002	2001
Operating Revenues (in thousands)	**$6,634,203**	$5,370,808	$4,913,507	$4,822,460	$4,965,794
Net Income after Dividends on Preferred Stock (in thousands)	**$714,999**	$658,001	$630,577	$617,629	$610,335
Cash Dividends on Common Stock (in thousands)	**$556,100**	$565,500	$565,800	$542,900	$527,300
Return on Average Common Equity (percent)	**14.15**	13.95	14.05	13.99	14.12
Total Assets (in thousands)	**$17,047,783**	$15,822,338	$14,850,754	$14,342,656	$14,447,973
Gross Property Additions (in thousands)	**$906,248**	$1,126,064	$742,810	$883,968	$1,389,751
Capitalization (in thousands):					
Common stock equity	**$5,214,535**	$4,890,561	$4,540,211	$4,434,447	$4,397,485
Preferred stock	**-**	14,609	14,569	14,569	14,569
Mandatorily redeemable preferred securities	**-**	-	940,000	940,000	789,250
Long-term debt payable to affiliated trusts	**969,073**	969,073	-	-	-
Long-term debt	**4,179,218**	3,709,852	3,762,333	3,109,619	2,961,726
Total (excluding amounts due within one year)	**$10,362,826**	$9,584,095	$9,257,113	$8,498,635	$8,163,030
Capitalization Ratios (percent):					
Common stock equity	**50.3**	51.0	49.0	52.2	53.9
Preferred stock	**-**	0.2	0.2	0.2	0.2
Mandatorily redeemable preferred securities	**-**	-	10.2	11.1	9.6
Long-term debt payable to affiliated trusts	**9.4**	10.1	-	-	-
Long-term debt	**40.3**	38.7	40.6	36.5	36.3
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Security Ratings:					
Preferred Stock -					
Moody's	**Baa1**	Baa1	Baa1	Baa1	Baa1
Standard and Poor's	**BBB+**	BBB+	BBB+	BBB+	BBB+
Fitch	**A**	A	A	A	A
Unsecured Long-Term Debt -					
Moody's	**A2**	A2	A2	A2	A2
Standard and Poor's	**A**	A	A	A	A
Fitch	**A+**	A+	A+	A+	A+
Customers (year-end):					
Residential	**1,832,520**	1,801,426	1,768,662	1,734,430	1,698,407
Commercial	**270,373**	265,543	258,276	250,993	244,674
Industrial	**8,206**	7,676	7,899	8,240	8,046
Other	**3,536**	3,482	3,434	3,328	3,239
Total	**2,114,635**	2,078,127	2,038,271	1,996,991	1,954,366
Employees (year-end)	**8,713**	8,731	8,714	8,837	9,048

N/A = Not Applicable.

SELECTED FINANCIAL AND OPERATING DATA 2001-2005 (continued)
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	2005	2004	2003	2002	2001
Operating Revenues (in thousands):					
Residential	**$ 2,024,204**	$1,736,072	$1,583,082	$1,600,438	$1,507,031
Commercial	**2,206,252**	1,812,096	1,661,054	1,631,130	1,682,918
Industrial	**1,351,731**	1,172,936	1,012,267	1,004,288	1,106,420
Other	**60,625**	55,881	53,569	52,241	52,943
Total retail	**5,642,812**	4,776,985	4,309,972	4,288,097	4,349,312
Sales for resale - non-affiliates	**519,673**	246,545	259,376	270,678	366,085
Sales for resale - affiliates	**264,989**	166,245	174,855	98,323	99,411
Total revenues from sales of electricity	**6,427,474**	5,189,775	4,744,203	4,657,098	4,814,808
Other revenues	**206,729**	181,033	169,304	165,362	150,986
Total	**$6,634,203**	$5,370,808	$4,913,507	$4,822,460	$4,965,794
Kilowatt-Hour Sales (in thousands):					
Residential	**23,585,115**	22,930,372	21,778,582	22,144,559	20,119,080
Commercial	**29,768,402**	28,014,357	26,940,572	26,954,922	26,493,255
Industrial	**25,027,371**	26,357,271	25,703,421	25,739,785	25,349,477
Other	**601,330**	602,202	595,742	593,202	583,007
Total retail	**78,982,218**	77,904,202	75,018,317	75,432,468	72,544,819
Sales for resale - non-affiliates	**11,234,527**	5,969,983	8,835,804	8,069,375	8,110,096
Sales for resale - affiliates	**4,854,914**	4,782,873	5,844,196	3,962,559	3,133,485
Total	**95,071,659**	88,657,058	89,698,317	87,464,402	83,788,400
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**8.58**	7.57	7.27	7.23	7.49
Commercial	**7.41**	6.47	6.17	6.05	6.35
Industrial	**5.40**	4.45	3.94	3.90	4.36
Total retail	**7.14**	6.13	5.75	5.68	6.00
Sales for resale	**4.88**	3.84	2.96	3.07	4.14
Total sales	**6.76**	5.85	5.29	5.32	5.75
Residential Average Annual Kilowatt-Hour Use Per Customer	**12,974**	12,838	12,421	12,867	11,933
Residential Average Annual Revenue Per Customer	**$1,113**	$972	$903	$930	$894
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**15,097**	13,978	13,980	14,059	14,474
Maximum Peak-Hour Demand (megawatts):					
Winter	**13,501**	12,208	13,153	11,873	11,977
Summer	**15,953**	15,180	14,826	14,597	14,294
Annual Load Factor (percent)	**59.7**	61.5	61.0	60.4	61.7
Plant Availability (percent):					
Fossil-steam	**90.7**	90.3	87.6	80.9	88.5
Nuclear	**89.3**	94.8	94.2	88.8	94.4
Source of Energy Supply (percent):					
Coal	**60.8**	57.9	58.6	59.5	58.5
Nuclear	**15.1**	17.3	16.8	16.2	18.1
Hydro	**1.9**	1.5	2.1	0.9	1.1
Oil and gas	**2.9**	0.1	0.3	0.3	0.4
Purchased power -					
From non-affiliates	**5.7**	7.0	7.5	6.3	7.8
From affiliates	**13.6**	16.2	14.7	16.8	14.1
Total	**100.0**	100.0	100.0	100.0	100.0

DIRECTORS AND OFFICERS
Georgia Power Company 2005 Annual Report

Directors

Juanita Powell Baranco
Executive Vice President
Baranco Acura
(Resigned effective 2/21/2006)

Gus H. Bell, III – *Nominee*
Chairman, President and Chief Executive Officer
Hussey, Gay, Bell and DeYoung - A Bell Company

Robert L. Brown, Jr.
President and Chief Executive Officer
R. L. Brown & Associates, Inc.

Ronald D. Brown
President and Chief Executive Officer
Atlanta Life Financial Group

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

Michael D. Garrett
President and Chief Executive Officer
Georgia Power Company

David M. Ratcliffe
President and Chief Executive Officer
The Southern Company

D. Gary Thompson
Retired from
Wachovia Corporation

Richard W. Ussery
Retired from
Total System Services (TSYS)

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

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

Officers

Michael D. Garrett
President and Chief Executive Officer
Georgia Power Company

William C. Archer, III
Executive Vice President
External Affairs
(Retirement effective 3/19/2006)

Mickey A. Brown
Executive Vice President
Customer Service Organization

Cliff S. Thrasher
Executive Vice President, Chief Financial Officer
and Treasurer

Christopher C. Womack
Executive Vice President (Effective 3/11/2006)
External Affairs

Judy M. Anderson
Senior Vice President
Charitable Giving

Richard L. Holmes
Senior Vice President
Metro Region

E. Lamont Houston
Senior Vice President (Effective 1/14/2006)
Customer Service and Sales

Douglas E. Jones
Senior Vice President (Effective 3/11/2006)
Fossil and Hydro Generation

James H. Miller III
Senior Vice President and
General Counsel

Leslie R. Sibert
Vice President
Transmission

Gene L. Ussery
Vice President
Distribution

DIRECTORS AND OFFICERS

Georgia Power Company 2005 Annual Report

Michael K. Anderson
Vice President (Effective 1/14/2006)
Corporate Services

W. Craig Barrs
Vice President

Robert A. Bell
Vice President (Effective 2/15/2006)
Human Resources

Rebecca A. Blalock
Vice President
Information Technology

P. Mike Clanton
Vice President (Effective 1/14/2006)
Customer Service

Ann P. Daiss
Vice President, Comptroller and
Chief Accounting Officer (Effective 3/11/2006)

Walter Dukes
Region Vice President
East

A. Bryan Fletcher
Vice President
Supply Chain Management

J. Kevin Fletcher
Vice President
Community and Economic Development

Jeff G. Franklin
Region Vice President
Northwest

Oscar C. Harper IV
Vice President (Effective 2/11/2006)
Resource Planning and Nuclear Development

O. Ben Harris
Vice President
Land

W. Ron Hinson
Vice President, Comptroller and
Chief Accounting Officer (Resigned effective
3/11/2006)

Ed F. Holcombe
Vice President
Governmental and Regulatory Affairs

Charles H. Huling
Vice President
Environmental Affairs

Anne H. Kaiser
Vice President
Sales

Ellen N. Lindemann
Vice President (Resigned effective 2/1/2006)
Human Resources

Jacki W. Lowe
Region Vice President
West

Daniel M. Lowery
Corporate Secretary

Terri H. Lupo
Region Vice President
South

Frank J. McCloskey
Vice President
Diversity

Robert B. Morris
Assistant Comptroller and Assistant Secretary

James E. Sykes, Jr.
Region Vice President
Northeast

Mark K. Tate
Assistant Comptroller

Jeff L. Wallace
Vice President (Resigned effective 2/11/2006)
Planning and Utility Relations

Thomas J. Wicker
Region Vice President
Central

W. Tal Wright
Vice President
Corporate Communication

Wayne Boston
Assistant Secretary and
Assistant Treasurer

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

Profile
The Company produces and delivers electricity as an integrated utility to retail customers within the State of Georgia and to wholesale customers in the Southeast. The Company sells electricity to approximately 2.1 million customers within its service area of approximately 57,000 square miles. In 2005, retail energy sales accounted for 83 percent of the Company's total sales of 95.1 billion kilowatt-hours.

The Company is a wholly owned subsidiary of The Southern Company, which is the parent company of five retail operating companies and a wholesale generation subsidiary, as well as other direct and indirect subsidiaries. There is no established public trading market for the Company's common stock.

Trustee, Registrar and Interest Paying Agent
All series of Senior Notes and Trust Preferred Securities
JPMorgan Chase Bank, N.A.
Institutional Trust Services
4 New York Plaza, 15th Floor
New York, NY 10004

Number of Preferred Shareholders of record as of December 31, 2005, was 1,003.

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

Georgia Power Company
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Atlanta, GA 30308-3374
(404) 506-6526

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Atlanta, GA 30303

Legal Counsel
Troutman Sanders LLP
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