GEORGIA POWER COMPANY

2010 Annual Report

GEORGIA POWER
A SOUTHERN COMPANY

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Georgia Power Company 2010 Annual Report

The management of Georgia Power Company (the "Company") is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2010.

W. Paul Bowers
President and Chief Executive Officer

Ronnie R. Labrato
Executive Vice President, Chief Financial Officer, and Treasurer

February 25, 2011

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, 2010 and 2009, 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, 2010. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the 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, such financial statements (pages 31 to 76) present fairly, in all material respects, the financial position of Georgia Power Company at December 31, 2010 and 2009, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
February 25, 2011

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 business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales given economic conditions, and to effectively manage and secure timely recovery of rising costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, and fuel prices. The Company is currently constructing two new nuclear and three new combined cycle generating units. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future. On December 21, 2010, the Georgia Public Service Commission (PSC) approved an Alternate Rate Plan for the years 2011 through 2013 (2010 ARP), including a base rate increase of approximately $562 million effective January 1, 2011. The Company is currently required to file its next fuel case by March 1, 2011.

Key Performance Indicators

In striving to maximize shareholder value while providing cost-effective 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 after dividends on preferred and preference stock. 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. The 2010 fossil/hydro Peak Season EFOR of 1.89% was better than the target. 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. The 2010 performance was better than the target for these reliability measures.

Net income after dividends on preferred and preference stock is the primary measure of the Company's financial performance. The Company's 2010 results compared to its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2010 Target Performance	2010 Actual Performance
Customer Satisfaction	**Top quartile in customer surveys**	**Top quartile in customer surveys**
Peak Season EFOR – fossil/hydro	**5.06% or less**	**1.89%**
Net Income after dividends on preferred and preference stock	**$905 million**	**$950 million**

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The performance achieved in 2010 reflects the continued emphasis that management places on these indicators as well as the commitment shown by employees in achieving or exceeding management's expectations.

Earnings

The Company's 2010 net income after dividends on preferred and preference stock totaled $950 million representing a $136 million, or 16.7%, increase over the previous year. The increase was due primarily to higher residential base revenues resulting from colder weather in the first and fourth quarters of 2010 and warmer weather in the second and third quarters of 2010 and increased amortization of the regulatory liability related to other cost of removal obligations as authorized by the Georgia PSC, partially offset by increases in operations and maintenance expenses. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Rate Plans" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information.

The Company's 2009 net income after dividends on preferred and preference stock totaled $814 million representing an $89 million, or 9.8%, decrease from 2008. The decrease was primarily related to lower commercial and industrial base revenues resulting from the recessionary economy and decreased revenues from market-response rates to large commercial and industrial customers that were partially offset by cost containment activities, increased recognition of environmental compliance cost recovery revenues, and the amortization of the regulatory liability related to other cost of removal obligations.

The Company's 2008 net income after dividends on preferred and preference stock totaled $903 million representing a $67 million, or 8.0%, increase over 2007. The increase was primarily related to increased contributions from market-response rates for large commercial and industrial customers, higher retail base revenues resulting from the retail rate increase effective January 1, 2008 (2007 Retail Rate Plan), and increased allowance for equity funds used during construction. These increases were partially offset by increased depreciation and amortization resulting from more plant in service and changes to depreciation rates.

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

	Amount	Increase (Decrease) from Prior Year		
	2010	**2010**	2009	2008
		(in millions)		
Operating revenues	**$ 8,349**	**$ 657**	$(720)	$ 840
Fuel	**3,102**	**385**	(95)	171
Purchased power	**946**	**(33)**	(426)	355
Other operations and maintenance	**1,734**	**240**	(88)	21
Depreciation and amortization	**558**	**(97)**	18	126
Taxes other than income taxes	**344**	**27**	1	24
Total operating expenses	**6,684**	**522**	(590)	697
Operating income	**1,665**	**135**	(130)	143
Total other income and (expense)	**(245)**	**44**	(37)	5
Income taxes	**453**	**43**	(78)	70
Net income	**967**	**136**	(89)	78
Dividends on preferred and preference stock	**17**	**-**	-	11
Net income after dividends on preferred and preference stock	**$ 950**	**$ 136**	$ (89)	$ 67

Operating Revenues

Operating revenues in 2010, 2009, and 2008 and the percent of change from the prior year were as follows:

	Amount		
	2010	2009	2008
		(in millions)	
Retail – prior year	**$ 6,912**	$ 7,286	$ 6,498
Estimated change in –			
Rates and pricing	**-**	(64)	397
Sales growth (decline)	**48**	(92)	(22)
Weather	**207**	(6)	(37)
Fuel cost recovery	**441**	(212)	450
Retail – current year	**7,608**	6,912	7,286
Wholesale revenues –			
Non-affiliates	**380**	395	569
Affiliates	**53**	112	286
Total wholesale revenues	**433**	507	855
Other operating revenues	**308**	273	271
Total operating revenues	**$ 8,349**	$ 7,692	$ 8,412
Percent change	**8.5%**	(8.6)%	11.1%

Retail base revenues of $4.2 billion in 2010 increased by $255 million, or 6.5%, from 2009 primarily due to colder weather in the first and fourth quarters of 2010 and warmer weather in the second and third quarters of 2010. Residential base revenues increased $187 million, or 10.9%, commercial base revenues increased $50 million, or 3.1%, and industrial base revenues increased $17 million, or 3.1%. Revenues from changes in rates and pricing in 2010 were flat as the increased recognition of environmental compliance cost recovery revenues in accordance with the 2007 Retail Rate Plan were offset by pricing reductions from the structure of the Company's base rate tariffs. Retail base revenues of $3.9 billion in 2009 decreased by $162 million, or 3.9%, from 2008 primarily due to lower industrial and commercial base revenues resulting from the recessionary economy and decreased revenues from market-response rates to large commercial and industrial customers. Industrial base revenues decreased $207 million, or 27.9%, and commercial base revenues decreased $36 million, or 2.1%. These decreases were partially offset by an increase in residential base revenues of $78 million, or 4.8%. All customer classes were positively affected by increased recognition of environmental compliance cost recovery revenues. Retail base revenues of $4.1 billion in 2008 increased by $338 million, or 9.0%, from 2007 primarily due to an increase in revenues from market-response rates to large commercial and industrial customers, the retail rate increase effective January 1, 2008, and a 0.7% increase in retail customers. The increase was partially offset by a weak economy in the Southeast and less favorable weather in 2008 than in 2007. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (decline) and weather.

Electric rates include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these fuel cost recovery provisions, fuel revenues generally equal fuel expenses, including the fuel component of purchased power, 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 as follows:

	2010	2009	2008
		(in millions)	
Unit power sales –			
Capacity	**$18**	$ 43	$ 40
Energy	**13**	26	44
Total	**31**	69	84
Other power sales –			
Capacity and other	**155**	140	129
Energy	**194**	186	356
Total	**349**	326	485
Total non-affiliated	**$380**	$395	$569

Wholesale revenues from sales to non-affiliates consist of power purchase agreements (PPA), unit power sales (UPS) contracts, and short-term opportunity sales. Wholesale revenues from PPAs and unit power sales contracts have both capacity and energy components. Capacity revenues reflect the recovery of fixed costs and a return on investment. Energy revenues from sales to non-affiliates will vary depending on the market cost of available energy compared to the cost of the Company and Southern Company system-owned generation, demand for energy within the Southern Company service territory, and availability of Southern Company system generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income.

Revenues from unit power sales decreased $38 million, or 55.1%, in 2010 as a result of the UPS contract expiring on May 31, 2010. Revenues from unit power sales decreased $15 million, or 18.9%, in 2009 primarily due to a 26.0% decrease in kilowatt-hour (KWH) energy sales due to the recessionary economy and generally unfavorable weather. Revenues from unit power sales increased $18 million, or 27.4%, in 2008 driven by higher fuel costs and an 8.2% increase in the KWH sales primarily related to sales by the Company's generating units when other Southern Company system units were unavailable. Revenues from other non-affiliated sales increased $23 million, or 7.1%, in 2010, decreased $159 million, or 32.7%, in 2009, and increased $13 million, or 2.7%, in 2008. The increase in 2010 was primarily due to higher fuel costs and revenues from a PPA that replaced the expired UPS contract discussed previously. The decrease in 2009 was due to lower natural gas prices and a 49.7% decrease in KWH sales due to the recessionary economy and generally unfavorable weather. The increase in 2008 was primarily driven by higher fuel and purchased power costs, partially offset by a 9.8% decrease in KWH sales and lower emissions allowance prices.

Wholesale revenues from sales to affiliated companies within the Southern Company system 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 Federal Energy Regulatory Commission (FERC). In 2010, wholesale revenues from sales to affiliates decreased 52.7% due to a 60.1% decrease in KWH sales as a result of lower demand because the market cost of available energy was lower than the cost of the Company's available generation. In 2009, wholesale revenues from sales to affiliates decreased 60.9% due to lower natural gas prices and a 32.2% decrease in KWH sales due to the recessionary economy and generally unfavorable weather. In 2008, KWH sales to affiliated companies decreased 28.8% while revenues from sales to affiliates increased 3.0%. The revenue increase in 2008 was primarily due to the increased cost of fuel and other marginal generation components of the rates. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost.

Other operating revenues increased $35 million, or 12.8%, in 2010 primarily due to a $25 million increase in transmission revenues related to increased usage of the Company's transmission system by non-affiliated companies, an increase of $4 million in outdoor lighting revenues primarily as a result of new customer sales associated with government stimulus programs, and an increase of $6 million in late payment fees and customer maintenance request revenues. Other operating revenues remained relatively flat in 2009. Other operating revenues increased $13 million, or 4.8%, in 2008 primarily due to a $7 million increase in revenues from outdoor lighting and an $8 million increase in customer fees resulting from higher rates that went into effect in 2008, partially offset by a $2 million decrease in equipment rentals revenue.

Energy Sales

Changes in revenues are influenced heavily by the change in volume of energy sold from year to year. KWH sales for 2010 and the percent change by year were as follows:

	Total KWHs	Total KWH Percent Change			Weather-Adjusted Percent Change		
	2010	**2010**	2009	2008	**2010**	2009	2008
	(in billions)						
Residential	**29.4**	**12.0%**	(0.5)%	(1.6)%	**0.9%**	(0.5)%	(0.6)%
Commercial	**33.9**	**3.9**	(1.4)	0.0	**(0.4)**	(0.9)	1.2
Industrial	**23.2**	**6.4**	(9.7)	(5.2)	**5.1**	(9.5)	(4.8)
Other	**0.7**	**(1.2)**	0.1	(3.8)	**(1.9)**	0.4	(3.6)
Total retail	**87.2**	**7.1**	(3.5)	(2.1)	**1.5%**	(3.2)%	(1.2)%
Wholesale							
Non-affiliates	**4.6**	**(10.5)**	(46.6)	(7.8)			
Affiliates	**1.0**	**(60.1)**	(32.2)	(28.8)			
Total wholesale	**5.6**	**(26.6)**	(42.7)	(14.7)			
Total energy sales	**92.8**	**4.2%**	(8.9)%	(4.0)%			

Changes in retail energy sales are comprised of changes in electricity usage by customers, changes in weather, and changes in the number of customers.

In 2010, residential KWH sales increased 12.0%, commercial KWH sales increased 3.9%, and industrial KWH sales increased 6.4% compared to 2009 primarily due to colder weather in the first and fourth quarters of 2010 and warmer weather in the second and third quarters of 2010 and an improving economy.

Residential KWH sales decreased 0.5% in 2009 compared to 2008 primarily due to slightly less favorable weather, partially offset by an increase of 0.2% in residential customers. Commercial and industrial KWH sales decreased 1.4% and 9.7%, respectively, in 2009 compared to 2008 due to the recessionary economy. During 2009, there was a broad decline in demand across all industrial segments, most significantly in the chemical, primary metals, textiles, and stone, clay, and glass sectors.

Residential KWH sales decreased 1.6% in 2008 compared to 2007 primarily due to less favorable weather, partially offset by a 0.7% increase in residential customers. Commercial KWH sales remained flat in 2008 compared to 2007 despite a 0.2% increase in commercial customers. Industrial KWH sales decreased 5.2% in 2008 over 2007 primarily due to reduced demand and closures within the textile and primary and fabricated metal industries, which were a result of the slowing economy that worsened during the fourth quarter 2008.

See "Operating Revenues" above for a discussion of significant changes in sales to non-affiliates and sales to affiliated companies.

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 demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market. Details of the Company's electricity generated and purchased were as follows:

	2010	2009	2008
Total generation *(billions of KWHs)*	**75.3**	72.4	80.8
Total purchased power *(billions of KWHs)*	**21.7**	20.4	21.3
Sources of generation *(percent)* -			
Coal	**67**	67	74
Nuclear	**21**	21	19
Gas	**10**	10	6
Hydro	**2**	2	1
Cost of fuel, generated *(cents per net KWH)* -			
Coal	**4.53**	4.12	3.44
Nuclear	**0.66**	0.55	0.51
Gas	**5.75**	5.30	6.90
Average cost of fuel, generated *(cents per net KWH)**	**3.82**	3.48	3.11
Average cost of purchased power *(cents per net KWH)*	**5.64**	6.06	8.10

*Fuel includes fuel purchased by the Company for tolling agreements where power is generated by the provider and is included in purchased power when determining the average cost of purchased power.

Fuel and purchased power expenses were $4.0 billion in 2010, an increase of $352 million, or 9.5%, compared to 2009. This increase was due to a $160 million increase in the average cost of fossil and nuclear fuel and a $192 million increase related to more KWHs generated primarily due to higher customer demand as a result of colder weather in the first and fourth quarters 2010 and warmer weather in the second and third quarters 2010.

Fuel and purchased power expenses were $3.7 billion in 2009, a decrease of $521 million, or 12.4%, below prior year costs. This decrease was due to a $371 million decrease related to fewer KWHs generated and purchased primarily due to lower customer demand as a result of the recessionary economy and a $150 million decrease in the average cost of purchased power, partially offset by an increase in the average cost of fuel.

Fuel and purchased power expenses were $4.2 billion in 2008, an increase of $526 million, or 14.3%, above prior year costs. Substantially all of this increase was due to the higher average cost of fuel and purchased power.

From an overall global market perspective, coal prices increased substantially in 2010 from the levels experienced in 2009, but remained lower than the unprecedented high levels of 2008. The slowly recovering U.S. economy and global demand from coal importing countries drove the higher prices in 2010, with concerns over regulatory actions, such as permitting issues, and their negative impact on production also contributing upward pressure. Domestic natural gas prices continued to be depressed by robust supplies, including production from shale gas, as well as lower demand. These lower natural gas prices contributed to increased use of natural gas fueled generating units in 2009 and 2010. Uranium prices remained relatively constant during the early portion of 2010 but rose steadily during the second half of the year. At year end, uranium prices remained well below the highs set during 2007. Worldwide uranium production levels increased in 2010; however, secondary supplies and inventories were still required to meet worldwide reactor demand.

Fuel expenses generally do not affect net income, since they are offset by fuel revenues under the Company's fuel cost recovery provisions. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information.

Other Operations and Maintenance Expenses

In 2010, other operations and maintenance expenses increased $240 million, or 16.1%, compared to 2009. The increase was due to increases of $142 million in power generation, $74 million in transmission and distribution, and $25 million in customer accounting, service, and sales due to cost containment efforts in 2009 as a result of economic conditions. The increase in power generation operations and maintenance expenses was also due to higher generation levels to meet increased customer demand in 2010.

In 2009, other operations and maintenance expenses decreased $88 million, or 5.5%, compared to 2008. The decrease was due to a $46 million decrease in power generation, a $28 million decrease in transmission and distribution, and a $32 million decrease in customer accounting, service, and sales, most of which were related to cost containment activities in an effort to offset the effects of the recessionary economy.

In 2008, other operations and maintenance expenses increased $21 million, or 1.2%, compared to 2007. The increase was primarily the result of a $15 million increase in the accrual for property damage approved under the 2007 Retail Rate Plan, a $15 million increase in scheduled outages and maintenance for fossil generating plants, and a $22 million increase related to meter reading, records and collections, and uncollectible account expenses. These increases were partially offset by decreases of $25 million related to the timing of transmission and distribution operations and maintenance and $7 million related to medical, pension, and other employee benefits.

Depreciation and Amortization

Depreciation and amortization decreased $97 million, or 14.8%, in 2010 compared to the prior year. This decrease was primarily due to a $133 million increase in amortization of the regulatory liability related to other cost of removal obligations, as authorized by the Georgia PSC, partially offset by increased depreciation related to additional plant in service related to transmission, distribution, and environmental projects. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Rate Plans" herein, Note 1 to the financial statements under "Depreciation and Amortization," and Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information.

Depreciation and amortization increased $18 million, or 2.9%, in 2009 compared to the prior year primarily due to additional plant in service related to transmission, distribution, and environmental projects, partially offset by the amortization of $41 million of the regulatory liability related to other cost of removal obligations.

Depreciation and amortization increased $126 million, or 24.6%, in 2008 compared to the prior year primarily due to an increase in plant in service related to completed transmission, distribution, and environmental projects, changes in depreciation rates effective January 1, 2008 approved under the 2007 Retail Rate Plan, and the expiration of amortization related to a regulatory liability for purchased power costs under the terms of the retail rate plan for the three years ended December 31, 2007.

Taxes Other Than Income Taxes

In 2010, taxes other than income taxes increased $27 million, or 8.5%, from the prior year primarily due to higher municipal franchise fees resulting from retail revenue increases during 2010. In 2009, the increase in taxes other than income taxes was immaterial. In 2008, taxes other than income taxes increased $24 million, or 8.6%, from the prior year primarily due to higher municipal franchise fees resulting from retail revenue increases during 2008.

Allowance for Funds Used During Construction Equity

Allowance for funds used during construction (AFUDC) equity increased $50 million, or 51.5%, in 2010 primarily due to the increase in construction related to three new combined cycle units at Plant McDonough, two new nuclear generating units at Plant Vogtle (Plant Vogtle Units 3 and 4), and ongoing environmental and transmission projects. In 2009, the increase in AFUDC equity as compared to 2008 was immaterial. AFUDC equity increased $27 million, or 39.8%, in 2008 primarily due to the increase in construction related to ongoing environmental and transmission projects, as well as the new units at Plant McDonough. See FUTURE EARNINGS POTENTIAL – "Construction" herein and Note 3 to the financial statements under "Construction" for additional information.

Interest Expense, Net of Amounts Capitalized

In 2010, interest expense, net of amounts capitalized decreased $11 million, or 2.8%, primarily due to a $14 million increase in interest capitalized in 2010 compared to the prior year. In 2009, interest expense, net of amounts capitalized increased $41 million, or 11.7%, primarily due to an increase in long-term debt levels resulting from the issuance of additional senior notes and pollution control bonds to fund the Company's ongoing construction program. The increase in interest expense in 2008 as compared to 2007 was immaterial.

Other Income (Expense), Net

Other income (expense), net decreased $20 million in 2010 primarily as a result of lower revenues of $9 million from non-operating activities and increased donations of $5 million. Other income (expense), net increased $7 million, or 80.8%, in 2009 primarily related to $2 million and $1 million increases in customer contracting and income resulting from purchases by large commercial and industrial customers of hedges against market-response rates, respectively, and a decrease of $2 million in donations. Other income (expense), net decreased $23 million, or 163.0%, in 2008 primarily due to a $13 million change in classification of revenues related to a residential pricing program to base retail revenues in 2008 as ordered by the Georgia PSC under the 2007 Retail Rate Plan, as well as decreased revenues of $7 million and $3 million related to non-operating rental income and customer contracting, respectively.

Income Taxes

Income taxes increased $43 million, or 10.5%, in 2010 primarily due to higher pre-tax earnings, partially offset by increases in non-taxable AFUDC equity and state tax credits. Income taxes decreased $78 million, or 15.9%, in 2009 primarily due to changes in pre-tax income. Income taxes increased $70 million, or 16.8%, in 2008 primarily due to increased pre-tax net income and the effect of deductions for the Company's donation of 2,200 acres in the Tallulah Gorge area to the State of Georgia in 2007. This increase was partially offset by an increase in AFUDC equity, as well as additional state tax credits and an increase in the federal production activities deduction.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

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. 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 wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and revenues are reviewed and may be adjusted periodically within certain limitations. 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" for additional information about 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 Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining 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 or decline in the Company's service area. Changes in economic conditions impact sales for the Company, and the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.

Environmental Matters

Compliance costs related to the Clean Air Act and other environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may exceed amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. The Company's environmental compliance cost recovery (ECCR) tariff allows for the recovery of capital and operations and maintenance costs related to environmental controls mandated by state and federal regulations.

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 certain Southern Company subsidiaries, including the Company, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The action was filed concurrently with the issuance of a notice of violation of the NSR provisions to the Company. After Alabama Power was dismissed from the original action, the EPA filed a separate action in January 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama. In these lawsuits, the EPA alleges that NSR violations occurred at eight coal-fired generating facilities operated by Alabama Power and the Company. The civil actions request penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The original action, now solely against the Company, has been administratively closed since the spring of 2001, and the case has not been reopened.

In June 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree between Alabama Power and the EPA, resolving a portion of the Alabama Power lawsuit relating to the alleged NSR violations at Plant Miller. In July 2008, the U.S. District Court for the Northern District of Alabama granted partial summary judgment in favor of Alabama Power with respect to its other affected units regarding the proper legal test for determining whether projects are routine maintenance, repair, and replacement and therefore are excluded from NSR permitting. On September 2, 2010, the EPA dismissed five of its eight remaining claims against Alabama Power, leaving only three claims for summary disposition or trial. The parties each filed motions for summary judgment on September 30, 2010. The court has set a trial date for October 2011 for any remaining claims.

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 $37,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures or affect the timing of currently budgeted capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot now be determined.

Carbon Dioxide Litigation

New York Case

In July 2004, three environmental groups and attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed complaints in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. 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. The 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 in October 2005 and, in September 2009, the U.S. Court of Appeals for the Second Circuit reversed the district court's ruling, vacating the dismissal of the plaintiffs' claim, and remanding the case to the district court. On December 6, 2010, the U.S. Supreme Court granted the defendants' petition for writ of certiorari. The ultimate outcome of these matters cannot be determined at this time.

Kivalina Case

In February 2008, the Native Village of Kivalina and the City of Kivalina filed a suit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs are the governing bodies of an Inupiat village in Alaska. The plaintiffs contend that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants have acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. Southern Company believes that these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case based on lack of jurisdiction and ruled the claims were barred by the political question doctrine and by the plaintiffs' failure to establish the standard for determining that the defendants' conduct caused the injury alleged. In November 2009, the plaintiffs filed an appeal with the U.S. Court of Appeals for the Ninth Circuit challenging the district court's order dismissing the case. On January 24, 2011, the defendants filed a motion with the U.S. Court of Appeals for the Ninth Circuit to defer scheduling the case pending the decision of the U.S. Supreme Court in the New York case discussed above. The ultimate outcome of this matter cannot be determined at this time.

Other Litigation

Common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas emissions have become more frequent, and, as illustrated by the New York and Kivalina cases, courts have been debating whether private parties and states have standing to bring such claims. In another common law nuisance case, the U.S. District Court for the Southern District of Mississippi dismissed private party claims against certain oil, coal, chemical, and utility companies alleging damages as a result of Hurricane Katrina. The court ruled that the parties lacked standing to bring the claims and the claims were barred by the political question doctrine. In October 2009, the U.S. Court of Appeals for the Fifth Circuit reversed the district court and held that the plaintiffs did have standing to assert their nuisance, trespass, and negligence claims and none of the claims were barred by the political question doctrine. On May 28, 2010, however, the U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal of the case based on procedural grounds, reinstating the district court decision in favor of the defendants. On January 10, 2011, the U.S. Supreme Court denied the plaintiffs' petition to reinstate the appeal. This case is now concluded.

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; the Endangered Species Act; and related federal and state regulations. 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 2010, the Company had invested approximately $3.7 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of $217 million, $440 million, and $689 million for 2010, 2009, and 2008, respectively. The Company expects that capital expenditures to comply with existing statutes and regulations will be $73 million, $79 million, and $58 million in 2011, 2012, and 2013, respectively. These environmental costs that are known and estimable at this time are included under the heading "Capital" in the table under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein. In addition, the Company currently estimates that potential incremental investments to comply with anticipated new environmental regulations could range from $69 million to $289 million in 2011, $191 million to $651 million in 2012, and $476 million to $1.4 billion in 2013. The Company's compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of any new or revised environmental statutes and regulations that are enacted, including the proposed environmental legislation and regulations described below; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix.

Compliance with any new federal or state legislation or regulations relating to global climate change, air quality, coal combustion byproducts, including coal ash, water quality, or other environmental and health concerns could also significantly affect the Company. Although new or revised environmental legislation or regulations could affect many areas of the Company's operations, the full impact of any such changes cannot be determined at this time. Additionally, many of the Company's commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity.

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 2010, the Company had spent approximately $3.4 billion in reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions and in monitoring emissions pursuant to the Clean Air Act. Additional controls are currently planned and others are under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone air quality standard. A 20-county area within metropolitan Atlanta is the only location within the Company's service area that is currently designated as nonattainment for the current standard. On November 30, 2010, the EPA extended the attainment date for this area by one year as a result of improving air quality. In March 2008, the EPA issued a final rule establishing a more stringent eight-hour ozone standard, and on January 6, 2010, the EPA proposed further reductions in the level of the standard. Under the EPA's current schedule, a final revision to the eight-hour ozone standard is expected in July 2011, with state implementation plans for any resulting nonattainment areas due in mid-2014. The revised eight-hour ozone standard is expected to result in designation of new nonattainment areas within the Company's service territory and could result in additional required reductions in NO_x emissions.

During 2005, the EPA's annual fine particulate matter nonattainment designations became effective for several areas within the Company's service area. State implementation plans demonstrating attainment with annual standards have been submitted to the EPA. The EPA is expected to propose new annual and 24-hour fine particulate matter standards during the summer of 2011.

Final revisions to the National Ambient Air Quality Standard for SO_2, including the establishment of a new one-hour standard, became effective on August 23, 2010. Since the EPA intends to rely on computer modeling for implementation of the SO_2 standard, the identification of potential nonattainment areas remains uncertain and could ultimately include areas within the Company's service territory. Implementation of the revised SO_2 standard could result in additional required reductions in SO_2 emissions and increased compliance and operation costs.

Revisions to the National Ambient Air Quality Standard for Nitrogen Dioxide (NO_2), which established a new one-hour standard, became effective on April 12, 2010. Although none of the areas within the Company's service territory are expected to be designated as nonattainment for the NO_2 standard, based on current ambient air quality monitoring data, the new NO_2 standard could result in significant additional compliance and operational costs for units that require new source permitting.

Twenty-eight eastern states, including the States of Georgia and Alabama, are subject to the requirements of the Clean Air Interstate Rule (CAIR). The rule calls for additional reductions of NO_x and/or SO_2 to be achieved in two phases, 2009/2010 and 2015. In July 2008 and December 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued decisions invalidating certain aspects of CAIR, but left CAIR compliance requirements in place while the EPA develops a revised rule. The States of Georgia and Alabama have completed their plans to implement CAIR, and emissions reductions are being accomplished by the installation and operation of emissions controls at the Company's coal-fired facilities and/or by the purchase of emissions allowances.

On August 2, 2010, the EPA published a proposed rule, referred to as the Transport Rule, to replace CAIR. This proposed rule would require 31 eastern states and the District of Columbia (D.C.) to reduce power plant emissions of SO_2 and NO_x that contribute to downwind states' nonattainment of federal ozone and/or fine particulate matter ambient air quality standards. To address fine particulate matter standards, the proposed Transport Rule would require D.C. and 27 eastern states, including Georgia and Alabama, to reduce annual emissions of SO_2 and NO_x from power plants. To address ozone standards, the proposed Transport Rule would also require D.C. and 25 states, including Georgia and Alabama, to achieve additional reductions in NO_x emissions from power plants during the ozone season. The proposed Transport Rule contains a "preferred option" that would allow limited interstate trading of emissions allowances; however, the EPA also requested comment on two alternative approaches that would not allow interstate trading of emissions allowances. The EPA stated that it also intends to develop a second phase of the Transport Rule in 2011 to address the more stringent ozone air quality standards after they are finalized. The EPA expects to finalize the Transport Rule in June 2011 and require compliance beginning in 2012.

The Clean Air Visibility Rule was finalized in July 2005, with a goal of restoring 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) to certain sources built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter. For power plants, the Clean Air Visibility Rule allows states to determine that CAIR satisfies BART requirements for SO_2 and NO_x, and no additional controls beyond CAIR are anticipated to be necessary at any of the Company's facilities. The State of Georgia is currently completing its implementation plan for BART compliance and other measures required to achieve the first phase of reasonable progress.

The EPA is currently developing a Maximum Achievable Control Technology (MACT) rule for coal- and oil-fired electric generating units which will establish emission limitations for numerous hazardous air pollutants, including mercury. As part of a proceeding in the U.S. District Court for the District of Columbia, the EPA has entered into a consent decree that requires the EPA to issue a proposed MACT rule by March 16, 2011 and a final rule by November 16, 2011.

On April 29, 2010, the EPA issued a proposed Industrial Boiler (IB) MACT rule that would establish emissions limits for various hazardous air pollutants typically emitted from industrial boilers, including biomass boilers and start-up boilers. The EPA issued the final rules on February 23, 2011 and, at the same time, issued a notice of intent to reconsider the final rules to allow for additional public review and comment. The impact of these regulations will depend on their final form and the outcome of any legal challenges and cannot be determined at this time.

The impacts of the eight-hour ozone, fine particulate matter, SO_2 and NO_2 standards, the proposed Transport Rule, the Clean Air Visibility Rule, and the proposed MACT rules for electric generating units and industrial boilers on the Company cannot be determined at this time and will depend on the specific provisions of the final rules, resolution of any pending and future legal challenges, and the development and implementation of rules at the state level. However, these additional regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the continuing and new environmental requirements discussed above. As part of this strategy, the Company has already installed a number of SO_2 and NO_x emissions controls to ensure continued compliance with applicable air quality requirements.

In addition to the federal air quality laws described above, the Company also is subject to the requirements of the State of Georgia's Multi-Pollutant Rule, which was adopted in 2007. The Multi-Pollutant Rule is designed to reduce emissions of mercury, SO_2, and NO_x state-wide by requiring the installation of specified control technologies at certain coal-fired generating units by specific dates between December 31, 2008 and June 1, 2015. The State of Georgia also adopted a companion rule that requires a 95% reduction in SO_2 emissions from the controlled units on the same or similar timetable. Through December 31, 2010, the Company had installed the required controls on 10 of its largest coal-fired generating units and is in the process of installing the required controls on six additional units. As a result of uncertainties related to the potential federal air quality regulations described above, the Company has suspended certain work related to both the installation of emissions control equipment at Plant Branch Units 1 and 2 and Plant Yates Units 6 and 7 and the conversion of Plant Mitchell from coal-fired to biomass-fired. The Company continues to analyze the potential costs and benefits of installing the required controls on its remaining coal-fired generating units in light of the potential federal regulations described above. The Company may determine that retiring and replacing certain of these existing units with new generating resources or purchased power is more economically efficient than installing the required environmental controls.

The Company currently expects to file an update to its integrated resource plan in June 2011. Under the terms of the 2010 ARP, any costs associated with changes to the Company's approved environmental operating or capital budgets (resulting from new or revised environmental regulations) through 2013 that are approved by the Georgia PSC in connection with an updated integrated resource plan will be deferred as a regulatory asset to be recovered over a time period deemed appropriate by the Georgia PSC. Such costs that may be deferred as a regulatory asset include any impairment losses that may result from a decision to retire certain units that are no longer cost effective in light of new or modified environmental regulations. In addition, in connection with the 2010 ARP, the Georgia PSC also approved revised depreciation rates that will recover the remaining book value of certain of the Company's existing coal-fired units by December 31, 2014.

The ultimate outcome of these matters cannot be determined at this time.

Water Quality

In July 2004, the EPA published final regulations under the Clean Water Act to reduce impingement and entrainment of fish, shellfish, and other forms of aquatic life at existing power plant cooling water intake structures. The use of cost-benefit analysis in the rule was ultimately appealed to the U.S. Supreme Court. In April 2009, the U.S. Supreme Court held that the EPA could consider costs in arriving at its standards and in providing variances from those standards for existing intake structures. The EPA is expected to propose revisions to the regulations in March 2011 and issue final regulations in mid-2012. While the U.S. Supreme Court's decision may ultimately result in greater flexibility for demonstrating compliance with the standards, the full scope of the regulations will depend on the specific provisions of the EPA's final rule and on the actual requirements established by state regulatory agencies and, therefore, cannot be determined at this time. However, if the final rules require the installation of cooling towers at certain existing facilities of the Company, the Company may be subject to significant additional compliance costs and capital expenditures that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

In December 2009, the EPA announced its determination that revision of the current effluent guidelines for steam electric power plants is warranted, and the EPA has announced its intention to adopt such revisions by January 2014. New wastewater treatment requirements are expected and may result in the installation of additional controls on certain of the Company's facilities. The impact of revised guidelines will depend on the studies conducted in connection with the rulemaking, as well as the specific requirements of the final rule, 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 releases of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Coal Combustion Byproducts

The Company currently operates 11 electric generating plants with on-site coal combustion byproduct storage facilities (some with both "wet" (ash ponds) and "dry" (landfill) storage facilities). In addition to on-site storage, the Company also sells a portion of its coal combustion byproducts to third parties for beneficial reuse (approximately one-fourth in recent years). Historically, individual states have regulated coal combustion byproducts and the states in Southern Company's service territory, including the States of Georgia and Alabama, each have their own regulatory parameters. The Company has a routine and robust inspection program in place to ensure the integrity of its coal ash surface impoundments and compliance with applicable regulations.

The EPA is currently evaluating whether additional regulation of coal combustion byproducts (including coal ash and gypsum) is merited under federal solid and hazardous waste laws. On June 21, 2010, the EPA published a proposed rule that requested comments on two potential regulatory options for the management and disposal of coal combustion byproducts: regulation as a solid waste or regulation as if the materials technically constituted a hazardous waste. Adoption of either option could require closure of, or significant change to, existing storage facilities and construction of lined landfills, as well as additional waste management and groundwater monitoring requirements. Under both options, the EPA proposes to exempt the beneficial reuse of coal combustion byproducts from regulation; however, a hazardous or other designation indicative of heightened risk could limit or eliminate beneficial reuse options.

On November 19, 2010, Southern Company filed publicly available comments with the EPA regarding the rulemaking proposal. These comments included a preliminary cost analysis under various alternatives in the rulemaking proposal. The Company regards these estimates as pre-screening figures that should be distinguished from the more formalized cost estimates the Company provides for projects that are more definite as to the elements and timing of execution. Although its analysis was preliminary, Southern Company concluded that potential compliance costs under the proposed rules would be substantially higher than the estimates reflected in the EPA's rulemaking proposal.

The ultimate financial and operational impact of any new regulations relating to coal combustion byproducts cannot be determined at this time and will be dependent upon numerous factors. These factors include: whether coal combustion byproducts will be regulated as hazardous waste or non-hazardous waste; whether the EPA will require early closure of existing wet storage facilities; whether beneficial reuse will be limited or eliminated through a hazardous waste designation; whether the construction of lined landfills is required; whether hazardous waste landfill permitting will be required for on-site storage; whether additional waste water treatment will be required; the extent of any additional groundwater monitoring requirements; whether any equipment modifications will be required; the extent of any changes to site safety practices under a hazardous waste designation; and the time period over which compliance will be required. There can be no assurance as to the timing of adoption or the ultimate form of any such rules.

While the ultimate outcome of this matter cannot be determined at this time, and will depend on the final form of any rules adopted and the outcome of any legal challenges, additional regulation of coal combustion byproducts could have a material impact on the generation, management, beneficial use, and disposal of such byproducts. Any material changes are likely to result in substantial additional compliance, operational, and capital costs that could affect future unit retirement and replacement decisions. Moreover, the Company could incur additional material asset retirement obligations with respect to closing existing storage facilities. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

Global Climate Issues

Although the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, with the goal of mandating renewable energy standards and reductions in greenhouse gas emissions, neither this legislation nor similar measures passed the U.S. Senate before the end of the 2010 session. Federal legislative proposals that would impose mandatory requirements related to greenhouse gas emissions, renewable energy standards, and/or energy efficiency standards are expected to continue to be considered in Congress.

The financial and operational impacts of climate or energy legislation, if enacted, will depend on a variety of factors. These factors include the specific greenhouse gas emissions limits or renewable energy requirements, the timing of implementation of these limits or requirements, the level of emissions allowances allocated and the level that must be purchased, the purchase price of emissions allowances, the development and commercial availability of technologies for renewable energy and for the reduction of emissions, the degree to which offsets may be used for compliance, provisions for cost containment (if any), the impact on coal, natural gas, and biomass prices, and cost recovery through regulated rates.

While climate legislation has yet to be adopted, the EPA is moving forward with regulation of greenhouse gases under the Clean Air Act. In April 2007, the U.S. Supreme Court ruled that the EPA has authority under the Clean Air Act to regulate greenhouse gas emissions from new motor vehicles. In December 2009, the EPA published a final determination, which became effective on January 14, 2010, that certain greenhouse gas emissions from new motor vehicles endanger public health and welfare due to climate change. On April 1, 2010, the EPA issued a final rule regulating greenhouse gas emissions from new motor vehicles under the Clean Air Act. The EPA has taken the position that when this rule became effective on January 2, 2011, carbon dioxide and other greenhouse gases became regulated pollutants under the Prevention of Significant Deterioration (PSD) preconstruction permit program and the Title V operating permit program, which both apply to power plants and other commercial and industrial facilities. As a result, the construction of new facilities or the major modification of existing facilities could trigger the requirement for a PSD permit and the installation of the best available control technology for carbon dioxide and other greenhouse gases. On May 13, 2010, the EPA issued a final rule, known as the Tailoring Rule, governing how these programs would be applied to stationary sources, including power plants. This rule establishes two phases for applying PSD and Title V requirements to greenhouse gas emissions sources. The first phase, which began on January 2, 2011, applies to sources and projects that would already be covered under PSD or Title V, whereas the second phase will begin on July 1, 2011 and applies to sources and projects that would not otherwise trigger those programs but for their greenhouse gas emissions. In addition to these rules, the EPA has entered into a proposed settlement agreement to issue standards of performance for greenhouse gas emissions from new and modified fossil fuel-fired electric generating units and greenhouse gas emissions guidelines for existing sources. Under the proposed settlement agreement, the EPA commits to issue the proposed standards by July 2011 and the final standards by May 2012.

All of the EPA's final Clean Air Act rulemakings have been challenged in the U.S. Court of Appeals for the District of Columbia Circuit; however, the court declined motions to stay the rules pending resolution of those challenges. As a result, the rules may impact the amount of time it takes to obtain PSD permits for new generation and major modifications to existing generating units and the requirements ultimately imposed by those permits. The ultimate outcome of these rules cannot be determined at this time and will depend on the content of the final rules and the outcome of any legal challenges.

International climate change negotiations under the United Nations Framework Convention on Climate Change also continue. The December 2009 negotiations resulted in a nonbinding agreement that included a pledge from both developed and developing countries to reduce their greenhouse gas emissions. The most recent round of negotiations took place in December 2010. The outcome and impact of the international negotiations cannot be determined at this time.

Although the outcome of federal, state, and international initiatives cannot be determined at this time, mandatory restrictions on the Company's greenhouse gas emissions or requirements relating to renewable energy or energy efficiency on the federal or state level are likely to result in significant additional compliance costs, including significant capital expenditures. These costs could affect future unit retirement and replacement decisions, and could result in the retirement of a significant number of coal-fired generating units. See Item 1 – BUSINESS – "Rate Matters – Integrated Resource Planning" for additional information. Also, additional compliance costs and costs related to unit retirements could affect results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

In 2009, the total carbon dioxide emissions from the fossil fuel-fired electric generating units owned by the Company were approximately 48 million metric tons. The preliminary estimate of carbon dioxide emissions from these units in 2010 is approximately 51 million metric tons. The level of carbon dioxide emissions from year to year will be dependent on the level of generation and mix of fuel sources, which is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units.

The Company is actively constructing new generating facilities with lower greenhouse gas emissions. These include Plant Vogtle Units 3 and 4 and three combined cycle units at Plant McDonough. The Company has also proposed the conversion of Plant Mitchell from coal-fired to biomass generation and is currently evaluating the costs and viability of other renewable technologies for the State of Georgia. On February 2, 2010, the Georgia PSC approved the Company's request to delay construction activities related to Plant Mitchell pending the EPA's anticipated issuance of regulations associated with coal combustion byproducts and the IB MACT rule described previously.

PSC Matters

Rate Plans

The economic recession significantly reduced the Company's revenues upon which retail rates were set by the Georgia PSC for 2008 through 2010 under the 2007 Retail Rate Plan. In June 2009, despite stringent efforts to reduce expenses, the Company's projected retail return on common equity (ROE) for both 2009 and 2010 was below 10.25%. However, in lieu of filing to increase customer rates as allowed under the 2007 Retail Rate Plan, in June 2009, the Company filed a request with the Georgia PSC for an accounting order that would allow the Company to amortize up to $324 million of its regulatory liability related to other cost of removal obligations.

In August 2009, the Georgia PSC approved the accounting order. Under the terms of the accounting order, the Company could amortize up to $108 million of the regulatory liability in 2009 and up to $216 million in 2010, limited to the amount needed to earn no more than a 9.75% and 10.15% retail ROE in 2009 and 2010, respectively. For the years ended December 31, 2009 and 2010, the Company amortized $41 million and $174 million of the regulatory liability, respectively.

On December 21, 2010, the Georgia PSC approved the 2010 ARP, which became effective January 1, 2011. The terms of the 2010 ARP reflect a settlement agreement among the Company, the Georgia PSC's Public Interest Advocacy Staff (PSC Staff), and eight other intervenors. Under the terms of the 2010 ARP, the Company will amortize approximately $92 million of its remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013.

Also under the terms of the 2010 ARP, effective January 1, 2011, the Company increased its (1) traditional base tariff rates by approximately $347 million; (2) Demand-Side Management (DSM) tariff rates by approximately $31 million; (3) ECCR tariff rate by approximately $168 million; and (4) Municipal Franchise Fee (MFF) tariff rate by approximately $16 million, for a total increase in base revenues of approximately $562 million.

Under the 2010 ARP, the following additional base rate adjustments will be made to the Company's tariffs in 2012 and 2013:

- Effective January 1, 2012, the DSM tariffs will increase by $17 million;
- Effective April 1, 2012, the traditional base tariffs will increase to recover the revenue requirements for the lesser of actual capital costs incurred or the amounts certified by the Georgia PSC for Plant McDonough Units 4 and 5 for the period from commercial operation through December 31, 2013;
- Effective January 1, 2013, the DSM tariffs will increase by $18 million;
- Effective January 1, 2013, the traditional base tariffs will increase to recover the revenue requirements for the lesser of actual capital costs incurred or the amounts certified by the Georgia PSC for Plant McDonough Unit 6 for the period from commercial operation through December 31, 2013; and
- The MFF tariff will increase consistent with these adjustments.

The Company currently estimates these adjustments will result in annualized base revenue increases of approximately $190 million in 2012 and $93 million in 2013.

Under the 2010 ARP, the Company's retail ROE is set at 11.15%, and earnings will be evaluated against a retail ROE range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25 % will be directly refunded to customers, with the remaining one-third retained by the Company. If at any time during the term of the 2010 ARP, the Company projects that retail earnings will be below 10.25% for any calendar year, it may petition the Georgia PSC for the implementation of an Interim Cost Recovery (ICR) tariff to adjust the Company's earnings back to a 10.25% retail ROE. The Georgia PSC will have 90 days to rule on any such request. If approved, any ICR tariff would expire at the earlier of January 1, 2014 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR, the Company may file a full rate case.

Except as provided above, the Company will not file for a general base rate increase while the 2010 ARP is in effect. The Company is required to file a general rate case by July 1, 2013, in response to which the Georgia PSC would be expected to determine whether the 2010 ARP should be continued, modified, or discontinued.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved increases in the Company's total annual billings of approximately $222 million effective June 1, 2008 and $373 million effective April 1, 2010. In addition, the Georgia PSC has authorized an interim fuel rider, which would allow the Company to adjust its fuel cost recovery rates prior to the next fuel case if the under recovered balance exceeds budget by more than $75 million. The Company is currently required to file its next fuel case by March 1, 2011.

The Company's under recovered fuel balance totaled approximately $398 million of which approximately $214 million is included in deferred charges and other assets in the balance sheets at December 31, 2010.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, a change in the billing factor has no significant effect on the Company's revenues or net income, but does impact annual cash flow. See Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Cost Recovery" for additional information.

Legislation

Stimulus Funding

On April 28, 2010, Southern Company signed a Smart Grid Investment Grant agreement with the U.S. Department of Energy (DOE), formally accepting a $165 million grant under the American Recovery and Reinvestment Act of 2009. This funding will be used for transmission and distribution automation and modernization projects that must be completed by April 28, 2013. The Company will receive, and will match, $51 million under the agreement. The ultimate outcome of this matter cannot be determined at this time.

Healthcare Reform

On March 23, 2010, the Patient Protection and Affordable Care Act (PPACA) was signed into law and, on March 30, 2010, the Health Care and Education Reconciliation Act of 2010 (together with PPACA, the Acts), which makes various amendments to certain aspects of the PPACA, was signed into law. The Acts effectively change the tax treatment of federal subsidies paid to sponsors of retiree health benefit plans that provide prescription drug benefits that are at least actuarially equivalent to the corresponding benefits provided under Medicare Part D. The federal subsidy paid to employers was introduced as part of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (MPDIMA). Since the 2006 tax year, the Company has been receiving the federal subsidy related to certain retiree prescription drug plans that were determined to be actuarially equivalent to the benefit provided under Medicare Part D. Under the MPDIMA, the federal subsidy does not reduce an employer's income tax deduction for the costs of providing such prescription drug plans nor is it subject to income tax individually. Under the Acts, beginning in 2013, an employer's income tax deduction for the costs of providing Medicare Part D-equivalent prescription drug benefits to retirees will be reduced by the amount of the federal subsidy. Under generally accepted accounting principles (GAAP), any impact from a change in tax law must be recognized in the period enacted regardless of the effective date. However, the Company deferred the related impact as a regulatory asset, which is being amortized over 12 years, in accordance with the 2010 ARP, and therefore had no material impact on the Company's financial statements. Southern Company continues to assess the extent to which the legislation and associated regulations may affect its future healthcare and related employee benefit plan costs. Any future impact on the Company's financial statements cannot be determined at this time. See Note 5 to the financial statements under "Current and Deferred Income Taxes" for additional information.

Income Tax Matters

Georgia State Income Tax Credits

The Company's 2005 through 2009 income tax filings for the State of Georgia include state income tax credits for increased activity through Georgia ports. The Company filed similar claims for the years 2002 through 2004. The Georgia Department of Revenue (DOR) has not responded to these claims. In July 2007, the Company filed a complaint in the Superior Court of Fulton County to recover the credits claimed for the years 2002 through 2004. On March 22, 2010, the Superior Court of Fulton County ruled in favor of the Company's motion for summary judgment. The Georgia DOR has appealed to the Georgia Court of Appeals and a decision is expected later this year. Any decision may be subject to further appeal to the Georgia Supreme Court. An unrecognized tax benefit has been recorded related to these credits. If the Company prevails, no material impact on the Company's net income is expected as a significant portion of any tax benefit is expected to be returned to retail customers in accordance with the 2010 ARP. If the Company is not successful, payment of the related state tax could have a significant, and possibly material, negative effect on the Company's cash flow. See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information. The ultimate outcome of this matter cannot now be determined.

Tax Method of Accounting for Repairs

The Company submitted a change in the tax accounting method for repair costs associated with the Company's generation, transmission, and distribution systems with the filing of the 2009 federal income tax return in September 2010. The new tax method resulted in net positive cash flow in 2010 of approximately $133 million for the Company. Although Internal Revenue Service (IRS) approval of this change is considered automatic, the amount claimed is subject to review because the IRS will be issuing final guidance on this matter. Currently, the IRS is working with the utility industry in an effort to resolve this matter in a consistent manner for all utilities. Due to uncertainty concerning the ultimate resolution of this matter, an unrecognized tax benefit has been recorded for the change in the tax accounting method for repair costs. See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information. The ultimate outcome of this matter cannot be determined at this time.

Bonus Depreciation

On September 27, 2010, the Small Business Jobs and Credit Act of 2010 (SBJCA) was signed into law. The SBJCA includes an extension of the 50% bonus depreciation for certain property acquired and placed in service in 2010 (and for certain long-term construction projects to be placed in service in 2011). Additionally, on December 17, 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term construction projects to be placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term construction projects to be placed in service in 2013), which could have a significant impact on the future cash flows of the Company.

The application of the bonus depreciation provisions in these acts in 2010 provided approximately $168 million in increased cash flow. The Company estimates the potential increased cash flow for 2011 to be between approximately $275 million and $350 million.

Internal Revenue Code Section 199 Domestic Production Deduction

The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in Section 199 of the Internal Revenue Code of 1986, as amended. The deduction is equal to a stated percentage of qualified production activities net income. The percentage was phased in over the years 2005 through 2010. For 2008 and 2009, a 6% reduction was available to the Company. Thereafter, the allowed rate is 9%; however, due to increased tax deductions from bonus depreciation and pension contributions there was no domestic production deduction available to the Company for 2010, and none is projected to be available for 2011. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Construction

Nuclear

In August 2009, the Nuclear Regulatory Commission (NRC) issued an Early Site Permit and Limited Work Authorization to Southern Nuclear, on behalf of the Company, Oglethorpe Power Corporation, the Municipal Electric Authority of Georgia, and the City of Dalton, Georgia, an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light, and Sinking Fund Commissioners (collectively, Owners), related to Plant Vogtle Units 3 and 4. See Note 4 to the financial statements for additional information on these co-owners. In March 2008, Southern Nuclear filed an application with the NRC for a combined construction and operating license (COL) for the new units. If licensed by the NRC, Plant Vogtle Units 3 and 4 are scheduled to be placed in service in 2016 and 2017, respectively.

In April 2008, the Company, acting for itself and as agent for the Owners, and a consortium consisting of Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc. (collectively, Consortium) entered into an engineering, procurement, and construction agreement to design, engineer, procure, construct, and test two AP1000 nuclear units with electric generating capacity of approximately 1,100 megawatts each and related facilities, structures, and improvements at Plant Vogtle (Vogtle 3 and 4 Agreement).

The Vogtle 3 and 4 Agreement is an arrangement whereby the Consortium supplies and constructs the entire facility with the exception of certain items provided by the Owners. Under the terms of the Vogtle 3 and 4 Agreement, the Owners agreed to pay a purchase price that will be subject to certain price escalations and adjustments, including fixed escalation amounts and certain index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. Each Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Consortium under the Vogtle 3 and 4 Agreement. The Company's proportionate share is 45.7%.

The Owners and the Consortium have agreed to certain liquidated damages upon the Consortium's failure to comply with the schedule and performance guarantees. The Consortium's liability to the Owners for schedule and performance liquidated damages and warranty claims is subject to a cap.

Certain payment obligations of Westinghouse and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and The Shaw Group, Inc., respectively. In the event of certain credit rating downgrades of any Owner, such Owner will be required to provide a letter of credit or other credit enhancement.

The Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Owners will be required to pay certain termination costs and, at certain stages of the work, cancellation fees to the Consortium. The Consortium may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including delays in receipt of the COL or delivery of full notice to proceed, certain Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Owners, Owner insolvency, and certain other events.

In March 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4. In addition, the Georgia PSC voted to approve the inclusion of the related construction work in progress accounts in rate base. In April 2009 the Governor of the State of Georgia signed into law the Georgia Nuclear Energy Financing Act that allows the Company to recover financing costs for nuclear construction projects by including the related construction work in progress accounts in rate base during the construction period. With respect to Plant Vogtle Units 3 and 4, this legislation allows the Company to recover projected financing costs of approximately $1.7 billion during the construction period beginning in 2011, which reduces the projected in-service cost to approximately $4.4 billion.

The Georgia PSC has ordered the Company to report against this total certified cost of approximately $6.1 billion. In addition, on December 21, 2010, the Georgia PSC approved the Company's Nuclear Construction Cost Recovery (NCCR) tariff. The NCCR tariff became effective January 1, 2011 and is expected to collect approximately $223 million in revenues during 2011.

On February 21, 2011, the Georgia PSC voted to approve the Company's third semi-annual construction monitoring report including total costs of $1.048 billion for Plant Vogtle Units 3 and 4 incurred through June 30, 2010. In connection with its certification of Vogtle Units 3 and 4, the Georgia PSC ordered the Company and the PSC Staff to work together to develop a risk sharing or incentive mechanism that would provide some level of protection to ratepayers in the event of significant cost overruns, but also not penalize the Company's earnings if and when overruns are due to mandates from governing agencies. Such discussions have continued through the third semi-annual construction monitoring proceedings; however, the Georgia PSC has deferred a decision with respect to any related incentive or risk-sharing mechanism until a later date. The Company will continue to file construction monitoring reports by February 28 and August 31 of each year during the construction period.

In 2009, the Southern Alliance for Clean Energy (SACE) and the Fulton County Taxpayers Foundation, Inc. (FCTF) filed separate petitions in the Superior Court of Fulton County, Georgia seeking review of the Georgia PSC's certification order and challenging the constitutionality of the Georgia Nuclear Energy Financing Act. On May 5, 2010, the court dismissed as premature the plaintiffs' claim challenging the Georgia Nuclear Energy Financing Act. FCTF appealed the decision, and the Georgia Supreme Court ruled against FCTF, finding the suit premature. In addition, on May 5, 2010, the Superior Court of Fulton County issued an order remanding the Georgia PSC's certification order for inclusion of further findings of fact and conclusions of law by the Georgia PSC. In compliance with the court's order, the Georgia PSC issued its order on remand to include further findings of fact and conclusions of law on June 23, 2010. On July 5, 2010, SACE and FCTF filed separate motions with the Georgia PSC for reconsideration of the order on remand. On August 17, 2010, the Georgia PSC voted to reaffirm its order. The matter is no longer subject to judicial review and is now concluded.

On December 2, 2010, Westinghouse submitted an AP1000 Design Certification Amendment (DCA) to the NRC. On February 10, 2011, the NRC announced that it was seeking public comment on a proposed rule to approve the DCA and amend the certified AP1000 reactor design for use in the U.S. The Advisory Committee on Reactor Safeguards also issued a letter on January 24, 2011 endorsing the issuance of the COL for Plant Vogtle Units 3 and 4. The Company currently expects to receive the COL for Plant Vogtle Units 3 and 4 from the NRC in late 2011 based on the NRC's February 16, 2011 release of its COL schedule framework.

There are other pending technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4. Similar additional challenges at the state and federal level are expected as construction proceeds.

The ultimate outcome of these matters cannot be determined at this time.

Other Construction

On May 6, 2010, the Georgia PSC approved the Company's request to extend the construction schedule for Plant McDonough Units 4, 5, and 6 as a result of the short-term reduction in forecasted demand, as well as the requested increase in the certified amount. As a result, the units are expected to be placed into service in January 2012, May 2012, and January 2013, respectively. To date, the Georgia PSC has approved the Company's quarterly construction monitoring reports, including actual project expenditures incurred, through June 30, 2010. The Company will continue to file quarterly construction monitoring reports throughout the construction period.

Other Matters

The Company is involved in various other matters being litigated, regulatory matters, and certain tax-related issues that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as opacity and air and water quality standards, has increased generally throughout the U.S. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, 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. 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 GAAP. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following 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 accounting standards which require 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 the accounting standards 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, 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 GAAP. 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, in accordance with GAAP, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. 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, coal combustion byproducts, including coal ash, control of toxic substances, hazardous and solid wastes, and other environmental matters.
- Changes in existing income tax regulations or changes in IRS or Georgia DOR 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 new or existing matters through the legislative process, the court systems, the IRS, the Georgia DOR, the FERC, or the EPA.

Unbilled Revenues

Revenues related to the retail 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.

Pension and Other Postretirement Benefits

The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, health care cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets, and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining the Company's pension and other postretirement benefit expense in accordance with GAAP are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. The Company discounts the future cash flows related to its postretirement benefit plans using a single-point discount rate developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments.

A 25 basis point change in any significant assumption would result in a $9 million or less change in total benefit expense and a $112 million or less change in projected obligations.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2010. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital" and "Financing Activities" herein for additional information.

The Company's investments in the qualified pension plan and the nuclear decommissioning trust funds remained stable in value as of December 31, 2010. In December 2010, the Company contributed $168 million to the qualified pension plan. The Company will fund approximately $3 million, $2 million, and $2 million to its nuclear decommissioning trust funds in 2011, 2012, and 2013, respectively.

Net cash provided from operating activities totaled $1.8 billion in 2010, an increase of $429 million from 2009, primarily due to a $136 million increase in net income, fuel inventory reductions in 2010 compared to additions in 2009, and a net increase of $94 million in deferred and prepaid income taxes primarily due to the extension of bonus depreciation and the change in the tax accounting method for repair costs (See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Tax Method of Accounting For Repairs" and "Bonus Depreciation" herein), partially offset by the contributions to the qualified pension plan. Net cash provided from operating activities totaled $1.4 billion in 2009, a decrease of $310 million from 2008, primarily due to an $89 million decrease in net income, a reduction in deferred revenues of approximately $172 million, a reduction in accrued compensation of approximately $123 million, and an increase in fuel inventory additions of approximately $150 million, partially offset by a reduction in accounts receivable of approximately $210 million. Net cash provided from operating activities totaled $1.7 billion in 2008, an increase of

$279 million from 2007, primarily due to higher retail operating revenues partially offset by higher inventory additions.

Net cash used for investing activities totaled $2.2 billion, $2.4 billion, and $1.9 billion in 2010, 2009, and 2008, respectively, due to gross property additions primarily related to installation of equipment to comply with environmental standards; construction of generation, transmission, and distribution facilities; and purchase of nuclear fuel. The majority of funds needed for gross property additions for the last several years have been provided from operating activities, capital contributions from Southern Company, and the issuance of debt.

Net cash provided from financing activities totaled $391 million, $881 million, and $310 million for 2010, 2009, and 2008, respectively. These totals are primarily related to additional issuances of senior notes and capital contributions from Southern Company in all years. The statements of cash flows provide additional details. See "Financing Activities" herein.

Significant balance sheet changes in 2010 include a $1.6 billion increase in total property, plant, and equipment related to the construction activities discussed above. Other significant balance sheet changes in 2010 include an increase in paid-in capital of $698 million reflecting equity contributions from Southern Company. Significant balance sheet changes in 2009 include a $1.9 billion increase in total property, plant, and equipment and a $776 million increase in long-term debt to provide funds for the Company's continuous construction program.

The Company's ratio of common equity to total capitalization, including short-term debt, was 48.8% in 2010 and 47.8% in 2009. See Note 6 to the financial statements for additional information.

Sources of Capital

Except as described below with respect to potential DOE loan guarantees, 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, security issuances, term loans, short-term borrowings, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend on prevailing market conditions, regulatory approvals, and other factors.

On June 18, 2010, the Company reached an agreement with the DOE to accept terms for a conditional commitment for federal loan guarantees that would apply to future borrowings by the Company related to the construction of Plant Vogtle Units 3 and 4. Any borrowings guaranteed by the DOE would be full recourse to the Company and secured by a first priority lien on the Company's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4. Total guaranteed borrowings would not exceed the lesser of 70% of eligible project costs or approximately $3.4 billion, and are expected to be funded by the Federal Financing Bank. Final approval and issuance of loan guarantees by the DOE are subject to receipt of the COL for Plant Vogtle Units 3 and 4 from the NRC, negotiation of definitive agreements, completion of due diligence by the DOE, receipt of any necessary regulatory approvals, and satisfaction of other conditions. There can be no assurance that the DOE will issue loan guarantees for the Company. See FUTURE EARNINGS POTENTIAL – "Construction – Nuclear" herein and Note 3 to the financial statements under "Construction – Nuclear" for more information on Plant Vogtle Units 3 and 4.

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. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended. The amounts of securities authorized by the Georgia PSC and the FERC 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 for under recovered fuel costs and to meet cash needs which can fluctuate significantly due to the seasonality of the business.

To meet short-term cash needs and contingencies, at December 31, 2010 the Company had credit arrangements with banks totaling $1.7 billion. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. In addition, the Company has substantial cash flow from operating activities and access to capital markets, including a commercial paper program, to meet liquidity needs.

At December 31, 2010, bank credit arrangements were as follows:

Total	Unused	Expires 2011	Expires 2012
	(in millions)		
$1,715	$1,703	$595	$1,120

Of the credit arrangements that expire in 2011, $40 million allow for the execution of term loans for an additional two-year period, and $220 million allow for execution of term loans for a one-year period. These credit arrangements provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper borrowings. As of December 31, 2010, the Company had $385 million outstanding pollution control revenue bonds requiring liquidity support. Subsequent to December 31, 2010, the Company's remarketing of $137 million of variable rate pollution control revenue bonds increased the total requiring liquidity support to $522 million.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional 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 benefit of any other operating company. The obligations of each company under these arrangements are several and there is no cross affiliate credit support. As of December 31, 2010, the Company had $575 million of outstanding commercial paper.

During 2010, the maximum amount of commercial paper outstanding was $575 million and the average amount outstanding was $167 million. During 2009, the maximum amount of commercial paper outstanding was $757 million and the average amount outstanding was $348 million. The weighted average annual interest rate on commercial paper in 2010 and 2009 was 0.3% and 0.4%, respectively. Management believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and cash.

Financing Activities

In March 2010, the Company issued $350 million aggregate principal amount of Series 2010A Floating Rate Senior Notes due March 15, 2013. The net proceeds were used to repay at maturity $250 million aggregate principal amount of Series 2008A Floating Rate Senior Notes due March 17, 2010, to repay a portion of its outstanding short-term indebtedness, and for general corporate purposes, including the Company's continuous construction program.

In June 2010, the Company issued $600 million aggregate principal amount of Series 2010B 5.40% Senior Notes due June 1, 2040. The net proceeds from the sale of the Series 2010B Senior Notes were used for the redemption of all of the $200 million aggregate principal amount of the Company's Series R 6.00% Senior Notes due October 15, 2033 and all of the $150 million aggregate principal amount of the Company's Series O 5.90% Senior Notes due April 15, 2033, to repay a portion of its outstanding short-term indebtedness, and for general corporate purposes, including the Company's continuous construction program.

In September 2010, the Company issued $500 million aggregate principal amount Series 2010C 4.75% Senior Notes due September 1, 2040. The net proceeds were used to redeem all of the $250 million aggregate principal amount of the Company's Series X 5.70% Senior Notes due January 15, 2045, $125 million aggregate principal amount of the Company's Series W 6.00% Senior Notes due August 15, 2044, $100 million aggregate principal amount of the Company's Series T 5.75% Senior Public Income Notes due January 15, 2044, and $35 million aggregate principal amount of the Company's Series G 5.75% Senior Notes due December 1, 2044.

Also in September 2010, the Company issued $500 million aggregate principal amount Series 2010D 1.30% Senior Notes due September 15, 2013. The net proceeds were used for the repurchase of all of the $114 million aggregate principal amount of outstanding Development Authority of Burke County Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 2009, due January 1, 2049; $40 million aggregate principal amount of the outstanding Development Authority of Monroe County Pollution Control Revenue Bonds (Georgia Power Company Plant Scherer Project), First Series 2009, due January 1, 2049; $173 million aggregate principal amount of the outstanding Development Authority of Bartow County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Bowen Project), First Series 2009, due December 1, 2032; $89 million aggregate principal amount of the outstanding Development Authority of Monroe County Pollution Control Revenue Bonds (Georgia Power Company Plant Scherer Project), Second Series 2009, due October 1, 2048; and $46 million aggregate principal amount of the outstanding Development Authority of Burke County Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 1996, due October 1, 2032, and for other general corporate purposes, including the Company's continuous construction program. The pollution control revenue bonds repurchased by the Company are being held by the Company and may be remarketed to investors in the future.

In December 2010, the Development Authority of Floyd County issued $53 million aggregate principal amount Pollution Control Revenue Bonds (Georgia Power Company Plant Hammond Project), First Series 2010 (the 2010 Bonds) for the benefit of the Company, and the 2010 Bonds were purchased by the Company. The proceeds from the issuance of the 2010 Bonds were used in December 2010 to purchase and cancel the $53 million aggregate principal amount Development Authority of Floyd County Pollution Control Revenue Bonds (Georgia Power Company Plant Hammond Project), First Series 2008. In January 2011, the Company remarketed the 2010 Bonds to investors.

Also subsequent to December 31, 2010, the Company issued $300 million aggregate principal amount of Series 2011A Floating Rate Senior Notes due January 15, 2013. The proceeds were used to repay a portion of the Company's outstanding short-term indebtedness and for general corporate purposes, including the Company's continuous construction program.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

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- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, energy price risk management, and construction of new generation. At December 31, 2010, the maximum potential collateral requirements under these contracts at a BBB- and/or Baa3 rating were approximately $27 million. At December 31, 2010, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $1.4 billion. Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market.

On August 12, 2010, Moody's Investors Service (Moody's) downgraded the issuer and long-term debt ratings of the Company (senior unsecured to A3 from A2). Moody's also announced that it had downgraded the short-term ratings of a financing subsidiary of Southern Company that issues commercial paper for the benefit of several Southern Company subsidiaries (including the Company) to P-2 from P-1. In addition, Moody's announced that it had downgraded the variable rate demand obligation ratings of the Company to VMIG-2 from VMIG-1 and the preferred and preference stock ratings of the Company to Baa2 from Baa1. Moody's also downgraded the trust preferred securities rating of the Company to Baa1 from A3. Moody's also announced that the ratings outlook for the Company is stable.

On December 22, 2010, Fitch Ratings, Inc. announced that the ratings outlook of the Company had been revised from negative to stable.

Market Price Risk

Due to cost-based rate regulation and other various cost recovery mechanisms, the Company continues to have 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, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's 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 enters into derivatives that have been designated as hedges. The weighted average interest rate on $1.0 billion of outstanding variable rate long-term debt at January 1, 2011 was 0.57%. 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 $10 million at January 1, 2011. For further information, see Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements.

To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, into financial hedge contracts for natural gas purchases. The Company continues to manage a fuel hedging program implemented per the guidelines of the Georgia PSC.

The changes in fair value of energy-related derivative contracts, the majority of which are composed of regulatory hedges, for the years ended December 31 were as follows:

	2010 Changes	2009 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (75)**	$ (113)
Contracts realized or settled	**85**	150
Current period changes[(a)]	**(110)**	(112)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (100)**	$ (75)

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

The change in the fair value positions of the energy-related derivative contracts for the year ended December 31, 2010 was a decrease of $25 million, substantially all of which is due to natural gas positions. The change is attributable to both the volume of million British thermal units (mmBtu) and the price of natural gas. At December 31, 2010, the Company had a net hedge volume of 58.7 million mmBtu with a weighted average contract cost approximately $1.74 per mmBtu above market prices, and 64.6 million mmBtu at December 31, 2009 with a weighted average contract cost approximately $1.16 per mmBtu above market prices. All natural gas hedges gains and losses are recovered through the Company's fuel cost recovery mechanism.

At December 31, 2010 and 2009, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and are related to the Company's fuel hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery mechanism. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are actively quoted, and thus fall into Level 2. See Note 10 to the financial statements for further discussion of fair value measurement. The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at December 31, 2010 were as follows:

	December 31, 2010 Fair Value Measurements			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
			(in millions)	
Level 1	$ -	$ -	$ -	$ -
Level 2	(100)	(77)	(23)	-
Level 3	-	-	-	-
Fair value of contracts outstanding at end of period	$ (100)	$ (77)	$ (23)	$ -

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related and interest rate derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and Standard & Poor's, a division of The McGraw Hill Companies, Inc., 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 Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) enacted in July 2010 could impact the use of over-the-counter derivatives by the Company. Regulations to implement the Dodd-Frank Act could impose additional requirements on the use of over-the-counter derivatives, such as margin and reporting requirements, which could affect both the use and cost of over-the-counter derivatives. The impact, if any, cannot be determined until regulations are finalized.

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to include a base level investment of $2.1 billion, $2.2 billion, and $2.0 billion for 2011, 2012, and 2013, respectively. Included in these estimated amounts are environmental expenditures to comply with existing statutes and regulations of $73 million, $79 million, and $58 million for 2011, 2012, and 2013, respectively. In addition, the Company currently estimates that potential incremental investments to comply with anticipated new environmental regulations could range from $69 million to $289 million in 2011, $191 million to $651 million in 2012, and $476 million to $1.4 billion in 2013. The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; changes in generating plants, including unit retirements and replacements, to meet new regulatory requirements; changes in FERC rules and regulations; Georgia PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. See Note 3 and Note 7 to the financial statements under "Construction – Nuclear" and "Construction Program," respectively, for additional information.

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."

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, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 6, 7, and 11 to the financial statements for additional information.

Contractual Obligations

	2011	2012-2013	2014-2015	After 2015	Uncertain Timing [d]	Total
			(in millions)			
Long-term debt[a] –						
Principal	$ 411	$ 1,575	$ 250	$ 6,069	$ -	$ 8,305
Interest	378	731	642	5,846	-	7,597
Preferred and preference stock dividends[b]	17	35	35	-	-	87
Energy-related derivative obligations[c]	77	24	-	-	-	101
Operating leases	36	37	22	8	-	103
Capital leases	4	9	11	35	-	59
Unrecognized tax benefits and interest[d]	203	-	-	-	61	264
Purchase commitments[e] –						
Capital[f]	1,858	3,878	-	-	-	5,736
Limestone [g]	17	36	30	10	-	93
Coal	1,869	1,538	786	1,182	-	5,375
Nuclear fuel	252	333	263	585	-	1,433
Natural gas[h]	445	984	769	2,665	-	4,863
Purchased power	316	509	464	1,726	-	3,015
Long-term service agreements[i]	18	102	111	467	-	698
Trusts –						
Nuclear decommissioning[j]	3	4	4	35	-	46
Pension and other postretirement benefit plans[k]	22	52	-	-	-	74
Total	$ 5,926	$ 9,847	$3,387	$ 18,628	$ 61	$ 37,849

(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, 2011, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts (shown separately).

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

(c) For additional information, see Notes 1 and 11 to the financial statements.

(d) The timing related to the realization of $61 million in unrecognized tax benefits and corresponding interest payments in individual years beyond 12 months cannot be reasonably and reliably estimated due to uncertainties in the timing of the effective settlement of tax positions. Of the total $264 million, $144 million is the estimated cash payment. See Note 3 under "Income Tax Matters" and Note 5 under "Unrecognized Tax Benefits" to the financial statements for additional information.

(e) The Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses for 2010, 2009, and 2008 were $1.7 billion, $1.5 billion, and $1.6 billion, respectively.

(f) The Company provides forecasted capital expenditures for a three-year period. Amounts represent current estimates of total expenditures, excluding those amounts related to contractual purchase commitments for nuclear fuel. In addition, such amounts exclude the Company's estimates of potential incremental investments to comply with anticipated new environmental regulations which could range from $69 million to $289 million in 2011, $191 million to $651 million in 2012, and $476 million to $1.4 billion in 2013. At December 31, 2010, significant purchase commitments were outstanding in connection with the construction program.

(g) As part of the Company's program to reduce SO_2 emissions from its coal plants, the Company has entered into various long-term commitments for the procurement of limestone to be used in flue gas desulfurization equipment.

(h) 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, 2010.

(i) Long-term service agreements include price escalation based on inflation indices.

(j) Projections of nuclear decommissioning trust fund contributions are based on the 2010 ARP.

(k) The Company forecasts contributions to the qualified pension and other postretirement benefit plans over a three-year period. The Company does not expect to be required to make any contributions to the qualified pension plan during the next three years. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2010 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales, retail rates, customer growth, economic recovery, fuel cost recovery and other rate actions, environmental regulations and expenditures, the Company's projections for qualified pension plan, other postretirement benefit plans, and nuclear decommissioning trust fund contributions, financing activities, impacts of the American Recovery and Reinvestment Act of 2009, impact of recent healthcare legislation, impact of the Small Business Jobs and Credit Act of 2010, impact of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, estimated sales and purchases under new power sale and purchase agreements, start and 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 changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, implementation of the Energy Policy Act of 2005, environmental laws including regulation of water quality, coal combustion byproducts, and emissions of sulfur, nitrogen, mercury, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, and also changes in 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 recovery from the recent recession, population, business growth (and declines), and the effects of energy conservation measures;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs and avoid cost overruns during the development and construction of facilities;
- investment performance of the Company's employee benefit plans and nuclear decommissioning trust funds;
- 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 and other cost recovery mechanisms;
- regulatory approvals and actions related to the Plant Vogtle expansion, including Georgia PSC and NRC approvals and potential DOE loan guarantees;
- 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 and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- 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, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- 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 SEC.

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

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STATEMENTS OF INCOME
For the Years Ended December 31, 2010, 2009, and 2008
Georgia Power Company 2010 Annual Report

	2010	2009	2008
		(in millions)	
Operating Revenues:			
Retail revenues	**$7,608**	$6,912	$7,286
Wholesale revenues, non-affiliates	**380**	395	569
Wholesale revenues, affiliates	**53**	112	286
Other revenues	**308**	273	271
Total operating revenues	**8,349**	7,692	8,412
Operating Expenses:			
Fuel	**3,102**	2,717	2,812
Purchased power, non-affiliates	**368**	269	443
Purchased power, affiliates	**578**	710	962
Other operations and maintenance	**1,734**	1,494	1,582
Depreciation and amortization	**558**	655	637
Taxes other than income taxes	**344**	317	316
Total operating expenses	**6,684**	6,162	6,752
Operating Income	**1,665**	1,530	1,660
Other Income and (Expense):			
Allowance for equity funds used during construction	**147**	97	95
Interest income	**5**	2	7
Interest expense, net of amounts capitalized	**(375)**	(386)	(345)
Other income (expense), net	**(22)**	(2)	(9)
Total other income and (expense)	**(245)**	(289)	(252)
Earnings Before Income Taxes	**1,420**	1,241	1,408
Income taxes	**453**	410	488
Net Income	**967**	831	920
Dividends on Preferred and Preference Stock	**17**	17	17
Net Income After Dividends on Preferred and Preference Stock	**$ 950**	$ 814	$ 903

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

STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2010, 2009, and 2008

Georgia Power Company 2010 Annual Report

	2010	2009	2008
		(in millions)	
Operating Activities:			
Net income	**$ 967**	$ 831	$ 920
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization, total	**724**	791	758
Deferred income taxes	**342**	191	171
Deferred revenues	**(101)**	(49)	123
Deferred expenses	**(13)**	(4)	2
Allowance for equity funds used during construction	**(147)**	(97)	(95)
Pension, postretirement, and other employee benefits	**21**	2	19
Pension and postretirement funding	**(195)**	(22)	(22)
Hedge settlements	**-**	(19)	(23)
Insurance cash surrender value	**1**	20	-
Other, net	**20**	24	2
Changes in certain current assets and liabilities --			
-Receivables	**168**	127	(83)
-Fossil fuel stock	**103**	(242)	(92)
-Materials and supplies	**(7)**	(6)	(20)
-Prepaid income taxes	**(36)**	21	(15)
-Other current assets	**(2)**	(1)	(18)
-Accounts payable	**(99)**	(54)	(56)
-Accrued taxes	**31**	(19)	118
-Accrued compensation	**62**	(101)	22
-Other current liabilities	**8**	25	17
Net cash provided from operating activities	**1,847**	1,418	1,728
Investing Activities:			
Property additions	**(2,190)**	(2,515)	(1,848)
Distribution of restricted cash from pollution control revenue bonds	**-**	27	33
Nuclear decommissioning trust fund purchases	**(1,772)**	(989)	(419)
Nuclear decommissioning trust fund sales	**1,768**	984	412
Cost of removal, net of salvage	**(67)**	(56)	(63)
Change in construction payables, net of joint owner portion	**36**	106	3
Other investing activities	**(19)**	25	(38)
Net cash used for investing activities	**(2,244)**	(2,418)	(1,920)
Financing Activities:			
Increase (decrease) in notes payable, net	**252**	(33)	(358)
Proceeds --			
Capital contributions from parent company	**688**	931	273
Pollution control revenue bonds issuances	**-**	417	386
Senior notes issuances	**1,950**	1,000	1,000
Other long-term debt issuances	**-**	1	301
Redemptions --			
Pollution control revenue bonds	**(516)**	(327)	(336)
Capital leases	**(3)**	(2)	(1)
Senior notes	**(1,112)**	(333)	(198)
Payment of preferred and preference stock dividends	**(18)**	(18)	(17)
Payment of common stock dividends	**(820)**	(739)	(721)
Other financing activities	**(30)**	(16)	(19)
Net cash provided from financing activities	**391**	881	310
Net Change in Cash and Cash Equivalents	**(6)**	(119)	118
Cash and Cash Equivalents at Beginning of Year	**14**	133	15
Cash and Cash Equivalents at End of Year	**$ 8**	$ 14	$ 133
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $54, $40 and $40 capitalized, respectively)	**$339**	$341	$309
Income taxes (net of refunds)	**149**	228	280

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

BALANCE SHEETS
At December 31, 2010 and 2009
Georgia Power Company 2010 Annual Report

Assets	2010	2009
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 8**	$ 14
Receivables --		
Customer accounts receivable	**580**	487
Unbilled revenues	**172**	172
Under recovered regulatory clause revenues	**184**	292
Joint owner accounts receivable	**60**	147
Other accounts and notes receivable	**67**	63
Affiliated companies	**21**	12
Accumulated provision for uncollectible accounts	**(11)**	(10)
Fossil fuel stock, at average cost	**624**	726
Materials and supplies, at average cost	**371**	363
Vacation pay	**78**	75
Prepaid income taxes	**99**	133
Other regulatory assets, current	**105**	77
Other current assets	**80**	61
Total current assets	**2,438**	2,612
Property, Plant, and Equipment:		
In service	**26,397**	25,120
Less accumulated provision for depreciation	**9,966**	9,493
Plant in service, net of depreciation	**16,431**	15,627
Nuclear fuel, at amortized cost	**386**	340
Construction work in progress	**3,287**	2,521
Total property, plant, and equipment	**20,104**	18,488
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**70**	66
Nuclear decommissioning trusts, at fair value	**818**	580
Miscellaneous property and investments	**42**	39
Total other property and investments	**930**	685
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**723**	609
Prepaid pension costs	**91**	-
Deferred under recovered regulatory clause revenues	**214**	373
Other regulatory assets, deferred	**1,207**	1,322
Other deferred charges and assets	**207**	206
Total deferred charges and other assets	**2,442**	2,510
Total Assets	**$25,914**	$24,295

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

BALANCE SHEETS

At December 31, 2010 and 2009

Georgia Power Company 2010 Annual Report

Liabilities and Stockholder's Equity	**2010**	2009
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 415**	$ 254
Notes payable	**576**	324
Accounts payable --		
Affiliated	**243**	239
Other	**574**	602
Customer deposits	**198**	200
Accrued taxes --		
Unrecognized tax benefits	**187**	165
Other accrued taxes	**328**	291
Accrued interest	**94**	89
Accrued vacation pay	**58**	58
Accrued compensation	**109**	43
Liabilities from risk management activities	**77**	50
Other cost of removal obligations, current	**31**	216
Other regulatory liabilities, current	**1**	100
Nuclear decommissioning trust securities lending collateral	**144**	14
Other current liabilities	**134**	69
Total current liabilities	**3,169**	2,714
Long-Term Debt (See accompanying statements)	**7,931**	7,782
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**3,718**	3,390
Deferred credits related to income taxes	**129**	134
Accumulated deferred investment tax credits	**229**	242
Employee benefit obligations	**684**	923
Asset retirement obligations	**705**	677
Other cost of removal obligations	**131**	125
Other deferred credits and liabilities	**211**	139
Total deferred credits and other liabilities	**5,807**	5,630
Total Liabilities	**16,907**	16,126
Preferred Stock (See accompanying statements)	**45**	45
Preference Stock (See accompanying statements)	**221**	221
Common Stockholder's Equity (See accompanying statements)	**8,741**	7,903
Total Liabilities and Stockholder's Equity	**$25,914**	$24,295
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2010 and 2009
Georgia Power Company 2010 Annual Report

	2010	2009	2010	2009
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term debt payable to affiliated trusts --				
5.88% due 2044	**$ 206**	$ 206		
Long-term notes payable --				
Variable rate (0.80% at 1/1/10) due 2010	**-**	250		
Variable rate (0.78% at 1/1/11) due 2011	**300**	300		
Variable rate (0.62% at 1/1/11) due 2013	**350**	-		
4.00% to 5.57% due 2011	**103**	103		
5.125% due 2012	**200**	200		
1.30% to 6.00% due 2013	**1,025**	525		
5.25% due 2015	**250**	250		
4.25% to 8.20% due 2017-2048	**4,351**	4,113		
Total long-term notes payable	**6,579**	5,741		
Other long-term debt --				
Pollution control revenue bonds:				
0.80% to 5.75% due 2016-2048	**1,134**	1,134		
Variable rate (0.39% at 1/1/11) due 2011	**8**	8		
Variable rate (0.33% to 0.46% at 1/1/11) due 2016-2041	**377**	893		
Total other long-term debt	**1,519**	2,035		
Capitalized lease obligations	**59**	63		
Unamortized debt discount	**(17)**	(9)		
Total long-term debt (annual interest requirement -- $377.7 million)	**8,346**	8,036		
Less amount due within one year	**415**	254		
Long-term debt excluding amount due within one year	**7,931**	7,782	**46.8%**	48.8%
Preferred and Preference Stock:				
Non-cumulative preferred stock				
$25 par value -- 6.125%				
Authorized - 50,000,000 shares				
Outstanding - 1,800,000 shares	**45**	45		
Non-cumulative preference stock				
$100 par value -- 6.50%				
Authorized - 15,000,000 shares				
Outstanding - 2,250,000 shares	**221**	221		
Total preferred and preference stock (annual dividend requirement -- $17.4 million)	**266**	266	**1.6**	1.7
Common Stockholder's Equity:				
Common stock, without par value --				
Authorized: 20,000,000 shares				
Outstanding: 9,261,500 shares	**398**	398		
Paid-in capital	**5,291**	4,593		
Retained earnings	**3,063**	2,933		
Accumulated other comprehensive income (loss)	**(11)**	(21)		
Total common stockholder's equity	**8,741**	7,903	**51.6**	49.5
Total Capitalization	**$16,938**	$15,951	**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, 2010, 2009, and 2008
Georgia Power Company 2010 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
			(in millions)			
Balance at December 31, 2007	9	$398	$3,375	$2,676	$(14)	$6,435
Net income after dividends on preferred and preference stock	-	-	-	903	-	903
Capital contributions from parent company	-	-	281	-	-	281
Other comprehensive loss	-	-	-	-	(19)	(19)
Cash dividends on common stock	-	-	-	(721)	-	(721)
Balance at December 31, 2008	9	398	3,656	2,858	(33)	6,879
Net income after dividends on preferred and preference stock	-	-	-	814	-	814
Capital contributions from parent company	-	-	937	-	-	937
Other comprehensive income	-	-	-	-	12	12
Cash dividends on common stock	-	-	-	(739)	-	(739)
Balance at December 31, 2009	**9**	**398**	**4,593**	**2,933**	**(21)**	**7,903**
Net income after dividends on preferred and preference stock	-	-	-	**950**	-	**950**
Capital contributions from parent company	-	-	**698**	-	-	**698**
Other comprehensive income	-	-	-	-	**10**	**10**
Cash dividends on common stock	-	-	-	**(820)**	-	**(820)**
Balance at December 31, 2010	**9**	**$ 398**	**$ 5,291**	**$ 3,063**	**$(11)**	**$ 8,741**

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

STATEMENTS OF COMPREHENSIVE INCOME

For the Years Ended December 31, 2010, 2009, and 2008

Georgia Power Company 2010 Annual Report

	2010	2009	2008
		(in millions)	
Net income after dividends on preferred and preference stock	**$950**	$814	$903
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $-, $(1), and $(13), respectively	**-**	(2)	(21)
Reclassification adjustment for amounts included in net income, net of tax of $6, $9, and $1, respectively	**10**	14	2
Total other comprehensive income (loss)	**10**	12	(19)
Comprehensive Income	**$960**	$826	$884

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

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1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Georgia Power Company (the Company) is a wholly owned subsidiary of Southern Company, which is the parent company of four traditional operating companies, Southern Power Company (Southern Power), Southern Company Services, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies – the Company, Alabama Power Company (Alabama Power), Gulf Power Company (Gulf Power), and Mississippi Power Company (Mississippi Power) – are vertically integrated utilities providing 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, acquires, owns, and manages generation assets and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public, and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary for Southern Company's investments in leveraged leases and various other energy-related businesses. Southern Nuclear operates and provides services to Southern Company's nuclear power plants, including the Company's Plants Hatch and Vogtle.

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 has an equity investment, but is not the primary beneficiary.

The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the Georgia Public Service Commission (PSC). The Company follows generally accepted accounting principles (GAAP) in the U.S. and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations and power pool operations. Costs for these services amounted to $552 million in 2010, $506 million in 2009, and $490 million in 2008. Cost allocation methodologies used by SCS were approved by the Securities and Exchange Commission prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

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, systems and procedures services, strategic planning and budgeting services, and other services with respect to business and operations. Costs for these services amounted to $473 million in 2010, $398 million in 2009, and $410 million in 2008.

The Company has entered into several power purchase agreements (PPA) with Southern Power for capacity and energy. Expenses associated with these PPAs were $199 million, $411 million, and $480 million in 2010, 2009, and 2008, respectively. Additionally, the Company had $26 million and $24 million of prepaid capacity expenses included in deferred charges and other assets in the balance sheets at December 31, 2010 and 2009, 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 Unit 3. Under this agreement, the Company operates Plant Scherer Unit 3 and Gulf Power reimburses the Company for its 25% proportionate share of the related non-fuel expenses, which were $9 million in 2010, $4 million in 2009, and $8 million in 2008. See Note 4 for additional information.

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any significant services to or from affiliates in 2010, 2009, or 2008.

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

The traditional 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.

Regulatory Assets and Liabilities

The Company is subject to the provisions of the Financial Accounting Standards Board in accounting for the effects of governmental regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

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

	2010	2009	Note
	(in millions)		
Deferred income tax charges	**$ 676**	$ 609	(a)
Deferred income tax charges – Medicare subsidy	**51**	-	(e)
Loss on reacquired debt	**176**	157	(b)
Vacation pay	**78**	75	(c, h)
Retiree benefit plans	**883**	952	(e, h)
Fuel-hedging (realized and unrealized) losses	**108**	82	(f)
Building leases	**45**	47	(i)
Generating plant outage costs	**31**	39	(j)
Other regulatory assets	**40**	49	(d)
Asset retirement obligations	**69**	116	(a, h)
Other cost of removal obligations	**(162)**	(341)	(a)
Deferred income tax credits	**(129)**	(134)	(a)
Environmental compliance cost recovery	**-**	(96)	(g)
Other regulatory liabilities	**(1)**	(1)	(b, f)
Total assets (liabilities), net	**$1,865**	$1,554	

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

(a) Asset retirement and deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 60 years. Asset retirement and other cost of removal liabilities will be settled and trued up following completion of the related activities. At December 31, 2010, other cost of removal obligations included $92 million that will be amortized over a three-year period beginning January 1, 2011 in accordance with a Georgia PSC order. See Note 3 under "Retail Regulatory Matters – Rate Plans" for additional information.

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

(d) Recorded and recovered or amortized as approved by the Georgia PSC over periods not exceeding five years.

(e) Recovered and amortized over the average remaining service period which may range up to 15 years. See Note 2 under "Pension Plans" and "Other Postretirement Benefits" and Note 5 under "Current and Deferred Income Taxes" for additional information.

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

(g) Deferred revenue associated with the levelization of the environmental compliance cost recovery (ECCR) tariff revenues for the years 2008 through 2010 in accordance with a Georgia PSC order.

(h) Not earning a return as offset in rate base by a corresponding asset or liability.

(i) See Note 6 under "Capital Leases." Recovered over the remaining lives of the buildings through 2026.

(j) See "Property, Plant, and Equipment." Recovered over the respective operating cycles, which range from 18 months to 10 years.

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off or reclassify to accumulated other comprehensive income (OCI) 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 write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are reflected in rates.

Revenues

Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract period. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs and 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% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense includes the cost of purchased emissions 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. See Note 3 under "Nuclear Fuel Disposal Costs" for additional information.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Investment tax credits utilized are deferred and amortized to income over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

In accordance with accounting standards related to the uncertainty in income taxes, the Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

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

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

	2010	2009
	(in millions)	
Generation	**$ 12,852**	$ 12,185
Transmission	**4,187**	3,891
Distribution	**7,855**	7,603
General	**1,475**	1,413
Plant acquisition adjustment	**28**	28
Total plant in service	**$ 26,397**	$ 25,120

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 outage costs over the unit's operating cycle. The refueling cycles are 18 and 24 months for Plants Vogtle and Hatch, respectively. Also, in accordance with a Georgia PSC 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.

The amount of non-cash property additions recognized for the years ended December 31, 2010, 2009 and 2008 was $310 million, $243 million, and $137 million, respectively. These amounts were comprised of construction related accounts payable outstanding at each year end together with retention amounts accrued during the respective year.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.0% in 2010 and 2009 and 2.9% in 2008. Depreciation studies are conducted periodically to update the composite rates that are approved by the Georgia PSC. Effective January 1, 2011, the Company's depreciation rates were revised by the Georgia PSC. 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. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

In August 2009, the Georgia PSC approved an accounting order allowing the Company to amortize a portion of its regulatory liability related to other cost of removal obligations. See Note 3 under "Retail Regulatory Matters – Rate Plans" for additional information.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations are computed as the present value of the ultimate costs for an asset's future retirement and are 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. The Company has received accounting guidance 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 are reflected in the balance sheets as a regulatory liability. See Note 3 under "Retail Regulatory Matters - Rate Plans" for additional information related to the Company's cost of removal regulatory liability.

The asset retirement obligation liability primarily relates to the Company's nuclear facilities, which include the Company's ownership interests in Plants Hatch and Vogtle. In addition, the Company has retirement obligations related to various landfill sites, ash ponds, underground storage tanks, and asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities, including the disposal of polychlorinated biphenyls in certain transformers; 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 the range of time over which the Company may settle these obligations is unknown and cannot be reasonably estimated. 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 in accordance with accounting standards related to asset retirement and environmental obligations 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:

	2010	2009
	(in millions)	
Balance at beginning of year	**$ 681**	$ 690
Liabilities incurred	**-**	2
Liabilities settled	**(12)**	(7)
Accretion	**43**	44
Cash flow revisions	**-**	(48)
Balance at end of year	**$ 712**	$ 681

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 (the 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 the Georgia PSC, as well as the Internal Revenue Service (IRS). The Funds are required to be held by one or more trustees with an individual net worth of at least $100 million. The FERC requires the Funds' managers to exercise the standard of care in investing that a "prudent investor" would use in the same circumstances. The FERC regulations also require, except for investments tied to market indices or other mutual funds, that the Funds' managers may not invest in any securities of the utility for which it manages funds or its affiliates. In addition, the NRC prohibits investments in securities of power reactor licensees. While the Company is allowed to prescribe an overall investment policy to the Funds' managers, the Company and its affiliates are not allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the Company's management. The Funds' managers are authorized, within broad limits, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

The Company records the investment securities held in the Funds at fair value, as disclosed in Note 10. Gains and losses, whether realized or unrealized, are recorded in the regulatory liability for asset retirement obligations in the balance sheets and are not included in net income or OCI. Fair value adjustments and realized gains and losses are determined on a specific identification basis.

The Funds participate in a securities lending program through the managers of the Funds. Under this program, the Funds' investment securities are loaned to investment brokers for a fee. Securities so loaned are fully collateralized by cash, letters of credit, and securities issued or guaranteed by the U.S. government, its agencies, and the instrumentalities. As of December 31, 2010 and 2009, approximately $141 million and $14 million, respectively, of the fair market value of the Funds' securities were on loan and pledged to creditors under the Funds' managers' securities lending program. The fair value of the collateral received was approximately $144 million and $14 million at December 31, 2010 and 2009, respectively, and can only be sold upon the return of the loaned securities. The collateral received is treated as a non-cash item in the statements of cash flows.

At December 31, 2010, investment securities in the Funds totaled $818 million, consisting of equity securities of $258 million, debt securities of $493 million, and $67 million of other securities. At December 31, 2009, investment securities in the Funds totaled $580 million, consisting of equity securities of $429 million, debt securities of $138 million, and $13 million of other securities. These amounts include the investment securities pledged to creditors and collateral received, and exclude receivables related to investment income and pending investment sales, and payables related to pending investment purchases and the lending pool.

Sales of the securities held in the Funds resulted in cash proceeds of $1.8 billion, $984 million, and $412 million in 2010, 2009, and 2008, respectively, all of which were reinvested. For 2010, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $74 million, of which $25 million of losses related to securities held in the Funds at December 31, 2010. For 2009, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $119 million, of which $118 million related to securities held in the Funds at December 31, 2009. For 2008, fair value reductions, including reinvested interest and dividends and excluding the Funds' expenses, were $(144) million. While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of and purpose for which the securities were acquired.

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 designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.

Site study cost is the estimate to decommission a specific facility as of the site study year. The estimated costs of decommissioning are based on the most current study performed in 2009. The site study costs and accumulated provisions for decommissioning as of December 31, 2010 based on the Company's ownership interests were as follows:

	Plant Hatch	Plant Vogtle
Decommissioning periods:		
Beginning year	2034	2047
Completion year	2063	2067
	(in millions)	
Site study costs:		
Radiated structures	$ 583	$ 500
Non-radiated structures	46	71
Total site study costs	$ 629	$ 571
Accumulated provision	$ 360	$ 206

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

For ratemaking purposes, the Company's decommissioning costs are based on the NRC generic estimate to decommission the radioactive portion of the facilities as of 2006. The NRC estimates are $575 million and $420 million for Plant Hatch and Plant Vogtle Units 1 and 2 , respectively. The Georgia PSC approved annual decommissioning costs for ratemaking of $3 million annually for Plant Vogtle Units 1 and 2 for 2008 through 2010. Under the Company's alternate rate plan, effective January 1, 2011 and continuing through December 31, 2013 (2010 ARP), the annual decommissioning cost for ratemaking is $2 million for Plant Hatch. Based on estimates approved in the 2010 ARP, the Company projects the external trust funds for Plant Vogtle Units 1 and 2 would be adequate to meet the decommissioning obligations of the NRC with no further contributions. Significant assumptions used to determine the costs for ratemaking include an estimated inflation rate of 2.4% and an estimated trust earnings rate of 4.4%. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for nuclear decommissioning costs.

Allowance for Funds Used During Construction (AFUDC)

In accordance with regulatory treatment, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new 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. The equity component of AFUDC is not included in calculating taxable income. For the years 2010, 2009, and 2008, the average AFUDC rates were 8.0%, 8.0%, and 8.2%, respectively, and AFUDC capitalized was $201 million, $137 million, and $135 million, respectively. AFUDC, net of income taxes, was 19.0%, 14.9%, and 13.3% of net income after dividends on preferred and preference stock for 2010, 2009, and 2008, respectively.

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 to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

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. Under the retail rate plan effective January 1, 2008 (2007 Retail Rate Plan), the Company accrued $21 million annually that was recoverable through base rates. Starting January 1, 2011, the Company will accrue $18 million annually under the 2010 ARP. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for storm damage costs.

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, at weighted average cost when installed.

Fuel Inventory

Fuel inventory includes the average costs of oil, coal, natural gas, and emissions allowances. Fuel is charged to inventory when purchased and then expensed as used and recovered by the Company through fuel cost recovery rates approved by the Georgia PSC. Emissions allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

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 (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 10 for additional information. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, 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 OCI 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. See Note 11 for additional information.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company has no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2010.

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.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, and 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 considered 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 in the balance sheets. See Note 6 under "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. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). In December 2010, the Company contributed approximately $168 million to the qualified pension plan. No contributions to the qualified pension plan are expected for the year ending December 31, 2011. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the FERC. For the year ending December 31, 2011, other postretirement trust contributions are expected to total approximately $22 million.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2007 for the 2008 plan year using a discount rate of 6.30% and an annual salary increase of 3.75%.

	2010	2009	2008
Discount rate:			
Pension plans	**5.52%**	5.93%	6.75%
Other postretirement benefit plans	**5.40**	5.83	6.75
Annual salary increase	**3.84**	4.18	3.75
Long-term return on plan assets:			
Pension plans	**8.75**	8.50	8.50
Other postretirement benefit plans	**7.24**	7.35	7.38

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of seven different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate of 8.25% for 2011, decreasing gradually to 5.00% through the year 2019 and remaining at that level thereafter. An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2010 as follows:

	1 Percent Increase	**1 Percent Decrease**
	(in millions)	
Benefit obligation	$ 63	$ 54
Service and interest costs	3	3

Pension Plans

The total accumulated benefit obligation for the pension plans was $2.5 billion in 2010 and $2.4 billion in 2009. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2010 and 2009 were as follows:

	2010	2009
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 2,517**	$ 2,238
Service cost	**54**	48
Interest cost	**145**	147
Benefits paid	**(127)**	(122)
Actuarial loss (gain)	**85**	206
Balance at end of year	**2,674**	2,517
Change in plan assets		
Fair value of plan assets at beginning of year	**2,237**	2,038
Actual return (loss) on plan assets	**335**	314
Employer contributions	**176**	7
Benefits paid	**(127)**	(122)
Fair value of plan assets at end of year	**2,621**	2,237
Accrued liability	**$ (53)**	$ (280)

At December 31, 2010, the projected benefit obligations for the qualified and non-qualified pension plans were $2.5 billion and $144 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2010 and 2009 related to the Company's pension plans consist of the following:

	2010	2009
	(in millions)	
Prepaid pension costs	**$ 91**	$ -
Other regulatory assets, deferred	**689**	734
Current liabilities, other	**(9)**	(8)
Employee benefit obligations	**(135)**	(272)

Presented below are the amounts included in regulatory assets at December 31, 2010 and 2009 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2011.

	2010	2009	Estimated Amortization in 2011
		(in millions)	
Prior service cost	**$ 61**	$ 73	**$ 12**
Net (gain) loss	**628**	661	**6**
Other regulatory assets, deferred	**$ 689**	$ 734	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2010 and 2009 are presented in the following table:

	Regulatory Assets
	(in millions)
Balance at December 31, 2008	$ 642
Net loss	108
Change in prior service costs	-
Reclassification adjustments:	
Amortization of prior service costs	(14)
Amortization of net gain	(2)
Total reclassification adjustments	(16)
Total change	92
Balance at December 31, 2009	$ 734
Net (gain)	**(30)**
Change in prior service costs	**-**
Reclassification adjustments:	
Amortization of prior service costs	**(13)**
Amortization of net gain	**(2)**
Total reclassification adjustments	**(15)**
Total change	**(45)**
Balance at December 31, 2010	**$ 689**

Components of net periodic pension cost (income) were as follows:

	2010	2009	2008
		(in millions)	
Service cost	**$ 54**	$ 48	$ 49
Interest cost	**145**	147	134
Expected return on plan assets	**(220)**	(216)	(211)
Recognized net loss	**2**	2	3
Net amortization	**13**	14	14
Net periodic pension cost (income)	**$ (6)**	$ (5)	$ (11)

Net periodic pension cost (income) is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

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, 2010, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2011	$ 139
2012	144
2013	149
2014	154
2015	160
2016 to 2020	889

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2010 and 2009 were as follows:

	2010	2009
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$ 782	$ 772
Service cost	9	10
Interest cost	44	50
Benefits paid	(44)	(43)
Actuarial (gain)/loss	(7)	8
Plan amendments	-	(18)
Retiree drug subsidy	2	3
Balance at end of year	786	782
Change in plan assets		
Fair value of plan assets at beginning of year	369	312
Actual return (loss) on plan assets	37	66
Employer contributions	29	31
Benefits paid	(42)	(40)
Fair value of plan assets at end of year	393	369
Accrued liability	$ (393)	$ (413)

Amounts recognized in the balance sheets at December 31, 2010 and 2009 related to the Company's other postretirement benefit plans consist of the following:

	2010	2009
	(in millions)	
Regulatory assets	$ 179	$ 202
Employee benefit obligations	(393)	(413)

Presented below are the amounts included in regulatory assets at December 31, 2010 and 2009 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2011.

	2010	2009	Estimated Amortization in 2011
		(in millions)	
Prior service cost	$ 10	$ 11	$ 1
Net (gain) loss	152	167	3
Transition obligation	17	24	7
Regulatory assets	$ 179	$ 202	

The changes in the balance of regulatory assets, related to the other postretirement benefit plans for the plan years ended December 31, 2010 and 2009 are presented in the following table:

	Regulatory Assets
	(in millions)
Balance at December 31, 2008	$ 261
Net gain	(28)
Change in prior service costs/transition obligation	(18)
Reclassification adjustments:	
Amortization of transition obligation	(8)
Amortization of prior service costs	(2)
Amortization of net gain	(3)
Total reclassification adjustments	(13)
Total change	(59)
Balance at December 31, 2009	$ 202
Net gain	**(13)**
Change in prior service costs/transition obligation	**-**
Reclassification adjustments:	
Amortization of transition obligation	**(6)**
Amortization of prior service costs	**(1)**
Amortization of net gain	**(3)**
Total reclassification adjustments	**(10)**
Total change	**(23)**
Balance at December 31, 2010	**$ 179**

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

	2010	2009	2008
		(in millions)	
Service cost	**$ 9**	$ 10	$ 10
Interest cost	**44**	50	50
Expected return on plan assets	**(30)**	(30)	(30)
Net amortization	**10**	13	16
Net postretirement cost	**$ 33**	$ 43	$ 46

The Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (Medicare Act) provides a 28% prescription drug subsidy for Medicare eligible retirees. The effect of the subsidy reduced the Company's expenses for the years ended December 31, 2010, 2009, and 2008 by approximately $11 million, $14 million, and $14 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 APBO for the other postretirement benefit 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)	
2011	$ 50	$ (3)	$ 47
2012	52	(4)	48
2013	54	(4)	50
2014	57	(5)	52
2015	59	(5)	54
2016 to 2020	307	(29)	278

Benefit Plan Assets

Pension plan and other postretirement benefit 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). In 2009, in determining the optimal asset allocation for the pension fund, the Company performed an extensive study based on projections of both assets and liabilities over a 10-year forward horizon. The primary goal of the study was to maximize plan funded status. The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2010 and 2009, along with the targeted mix of assets for each plan, is presented below:

	Target	**2010**	2009
Pension plan assets:			
Domestic equity	29%	**29%**	33%
International equity	28	**27**	29
Fixed income	15	**22**	15
Special situations	3	**-**	-
Real estate investments	15	**13**	13
Private equity	10	**9**	10
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	41%	**41%**	34%
International equity	22	**24**	29
Fixed income	31	**30**	32
Special situations	1	**-**	-
Real estate investments	3	**3**	3
Private equity	2	**2**	2
Total	100%	**100%**	100%

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices.

Investment Strategies

Detailed below is a description of the investment strategies for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** An actively-managed mix of growth stocks and value stocks with both developed and emerging market exposure.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Trust-owned life insurance.*** Investments of the Company's taxable trusts aimed at minimizing the impact of taxes on the portfolio.

- ***Special situations.*** Though currently unfunded, established both to execute opportunistic investment strategies with the objectives of diversifying and enhancing returns and exploiting short-term inefficiencies, as well as to invest in promising new strategies of a longer-term nature.
- ***Real estate investments.*** Investments in traditional private-market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2010 and 2009. The fair values presented are prepared in accordance with applicable accounting standards regarding fair value. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Securities for which the activity is observable on an active market or traded exchange are categorized as Level 1. Fixed income securities classified as Level 2 are valued using matrix pricing, a common model utilizing observable inputs. Domestic and international equity securities classified as Level 2 consist of pooled funds where the value is not quoted on an exchange but where the value is determined using observable inputs from the market. Securities that are valued using unobservable inputs are classified as Level 3 and include investments in real estate and investments in limited partnerships. The Company invests (through the pension plan trustee) directly in the limited partnerships which then invest in various types of funds or various private entities within a fund. The fair value of the limited partnerships' investments is based on audited annual capital accounts statements which are generally prepared on a fair value basis. The Company also relies on the fact that, in most instances, the underlying assets held by the limited partnerships are reported at fair value. External investment managers typically send valuations to both the custodian and to the Company within 90 days of quarter end. The custodian reports the most recent value available and adjusts the value for cash flows since the statement date for each respective fund.

The fair values of pension plan assets as of December 31, 2010 and 2009 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases.

	Fair Value Measurements Using			
As of December 31, 2010:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Domestic equity*	$ 486	$ 196	$ -	$ 682
International equity*	490	170	-	660
Fixed income:				
U.S. Treasury, government, and agency bonds	-	117	-	117
Mortgage- and asset-backed securities	-	95	-	95
Corporate bonds	-	226	1	227
Pooled funds	-	77	-	77
Cash equivalents and other	1	183	-	184
Special situations	-	-	-	-
Real estate investments	71	-	258	329
Private equity	-	-	245	245
Total	$ 1,048	$ 1,064	$ 504	$ 2,616

*Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

As of December 31, 2009:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 444	$ 184	$ -	$ 628
International equity*	574	57	-	631
Fixed income:				
U.S. Treasury, government, and agency bonds	-	165	-	165
Mortgage- and asset-backed securities	-	45	-	45
Corporate bonds	-	111	-	111
Pooled funds	-	4	-	4
Cash equivalents and other	1	136	-	137
Special situations	-	-	-	-
Real estate investments	69	-	217	286
Private equity	-	-	221	221
Total	$ 1,088	$ 702	$ 438	$ 2,228
Liabilities:				
Derivatives	(2)	-	-	(2)
Total	$ 1,086	$ 702	$ 438	$ 2,226

*Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Changes in the fair value measurement of the Level 3 items in the pension plan assets valued using significant unobservable inputs for the years ended December 31, 2010 and 2009 are as follows:

	2010		2009	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
		(in millions)		
Beginning balance	$ 217	$ 221	$ 336	$ 196
Actual return on investments:				
Related to investments held at year end	15	18	(98)	14
Related to investments sold during the year	7	7	(26)	4
Total return on investments	22	25	(124)	18
Purchases, sales, and settlements	19	(1)	5	7
Transfers into/out of Level 3	-	-	-	-
Ending balance	$ 258	$ 245	$ 217	$ 221

The fair values of other postretirement benefit plan assets as of December 31, 2010 and 2009 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases.

	Fair Value Measurements Using			
As of December 31, 2010:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 98	$ 33	$ -	$ 131
International equity*	16	39	-	55
Fixed income:				
U.S. Treasury, government, and agency bonds	-	4	-	4
Mortgage- and asset-backed securities	-	3	-	3
Corporate bonds	-	7	-	7
Pooled funds	-	28	-	28
Cash equivalents and other	-	11	-	11
Trust-owned life insurance	-	132	-	132
Special situations	-	-	-	-
Real estate investments	2	-	8	10
Private equity	-	-	8	8
Total	$ 116	$ 257	$ 16	$ 389

*Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

	Fair Value Measurements Using			
As of December 31, 2009:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 82	$ 29	$ -	$ 111
International equity*	20	31	-	51
Fixed income:				
U.S. Treasury, government, and agency bonds	-	5	-	5
Mortgage- and asset-backed securities	-	2	-	2
Corporate bonds	-	4	-	4
Pooled funds	-	17	-	17
Cash equivalents and other	-	26	-	26
Trust-owned life insurance	-	126	-	126
Special situations	-	-	-	-
Real estate investments	2	-	8	10
Private equity	-	-	8	8
Total	$ 104	$ 240	$ 16	$ 360

*Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Changes in the fair value measurement of the Level 3 items in the other postretirement benefit plan assets valued using significant unobservable inputs for the years ended December 31, 2010 and 2009 are as follows:

	2010		2009	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
		(in millions)		
Beginning balance	$ 8	$ 8	$ 12	$ 7
Actual return on investments:				
Related to investments held at year end	-	-	(3)	1
Related to investments sold during the year	-	-	(1)	-
Total return on investments	-	-	(4)	1
Purchases, sales, and settlements	-	-	-	-
Transfers into/out of Level 3	-	-	-	-
Ending balance	$ 8	$ 8	$ 8	$ 8

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2010, 2009, and 2008 were $23 million, $25 million, and $25 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 such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as opacity and air and water quality standards, has increased generally throughout the U.S. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, 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 EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including the Company, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The action was filed concurrently with the issuance of a notice of violation of the NSR provisions to the Company. After Alabama Power was dismissed from the original action, the EPA filed a separate action in January 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama. In these lawsuits, the EPA alleges that NSR violations occurred at eight coal-fired generating facilities operated by Alabama Power and the Company. The civil actions request penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The original action, now solely against the Company, has been administratively closed since the spring of 2001, and the case has not been reopened.

In June 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree between Alabama Power and the EPA, resolving a portion of the Alabama Power lawsuit relating to the alleged NSR violations at Plant Miller. In July 2008, the U.S. District Court for the Northern District of Alabama granted partial summary judgment in favor of Alabama Power with respect to its other affected units regarding the proper legal test for determining whether projects are routine maintenance, repair, and replacement and therefore are excluded from NSR permitting. On September 2, 2010, the EPA dismissed five of its eight remaining claims against

Alabama Power, leaving only three claims for summary disposition or trial. The parties each filed motions for summary judgment on September 30, 2010. The court has set a trial date for October 2011 for any remaining claims.

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 $37,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures or affect the timing of currently budgeted capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot now be determined.

Carbon Dioxide Litigation

New York Case

In July 2004, three environmental groups and attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed complaints in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. 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. The 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 in October 2005 and, in September 2009, the U.S. Court of Appeals for the Second Circuit reversed the district court's ruling, vacating the dismissal of the plaintiffs' claim, and remanding the case to the district court. On December 6, 2010, the U.S. Supreme Court granted the defendants' petition for writ of certiorari. The ultimate outcome of these matters cannot be determined at this time.

Kivalina Case

In February 2008, the Native Village of Kivalina and the City of Kivalina filed a suit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs are the governing bodies of an Inupiat village in Alaska. The plaintiffs contend that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants have acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. Southern Company believes that these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case based on lack of jurisdiction and ruled the claims were barred by the political question doctrine and by the plaintiffs' failure to establish the standard for determining that the defendants' conduct caused the injury alleged. In November 2009, the plaintiffs filed an appeal with the U.S. Court of Appeals for the Ninth Circuit challenging the district court's order dismissing the case. On January 24, 2011, the defendants filed a motion with the U.S. Court of Appeals for the Ninth Circuit to defer scheduling the case pending the decision of the U.S. Supreme Court in the New York case discussed above. The ultimate outcome of this matter cannot be determined at this time.

Other Litigation

Common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas emissions have become more frequent, and, as illustrated by the New York and Kivalina cases, courts have been debating whether private parties and states have standing to bring such claims. In another common law nuisance case, the U.S. District Court for the Southern District of Mississippi dismissed private party claims against certain oil, coal, chemical, and utility companies alleging damages as a result of Hurricane Katrina. The court ruled that the parties lacked standing to bring the claims and the claims were barred by the political question doctrine. In October 2009, the U.S. Court of Appeals for the Fifth Circuit reversed the district court and held that the plaintiffs did have standing to assert their nuisance, trespass, and negligence claims and none of the claims were barred by the political question doctrine. On May 28, 2010, however, the U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal of the case based on procedural grounds, reinstating the district court decision in favor of the defendants. On January 10, 2011, the U.S. Supreme Court denied the plaintiffs' petition to reinstate the appeal. This case is now concluded.

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties.

The Company maintains a reserve for environmental remediation as mandated by the Georgia PSC. The Company accrued $1 million annually for environmental remediation expenses during 2008 through 2010 that was recoverable through its ECCR tariff. Beginning in 2011, the Company is accruing approximately $3 million annually under the 2010 ARP. The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable and reduces the reserve as expenditures are incurred. Any difference between the liabilities accrued and cost recovered through rates is deferred as a regulatory asset or liability. The annual recovery amount is expected to be reviewed by the Georgia PSC and adjusted in future regulatory proceedings. As of December 31, 2010, the balance of the environmental remediation liability was $13 million, with approximately $3 million included in other regulatory assets, current and approximately $3 million included as other regulatory assets, deferred.

The Company has been designated or identified as a potentially responsible party (PRP) at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), including a large site in Brunswick, Georgia on the CERCLA National Priorities List (NPL). The parties have completed the removal of wastes from the Brunswick site as ordered by the EPA. Additional claims for recovery of natural resource damages at this site or for the assessment and potential cleanup of other sites on the Georgia Hazardous Sites Inventory and the CERCLA NPL are anticipated. The final outcome of these matters cannot be determined at this time. However, based on the currently known conditions at these sites and the nature and extent of activities relating to these sites, management does not believe that additional liabilities, if any, at these sites would be material to the financial statements.

In September 2008, the EPA advised the Company that it has been designated as a PRP at the Ward Transformer Superfund site located in Raleigh, North Carolina. Numerous other entities have also received notices regarding this site from the EPA. The Company, along with other named PRPs, is negotiating with the EPA to address cleanup of the site and reimbursement for past expenditures related to work performed at the site. In addition, in April 2009, two PRPs filed separate actions in the U.S. District Court for the Eastern District of North Carolina against numerous other PRPs, including the Company, seeking contribution from the defendants for expenses incurred by the plaintiffs related to work performed at a portion of the site. The ultimate outcome of these matters will depend upon further environmental assessment and the ultimate number of PRPs and cannot be determined at this time; however, as a result of the regulatory treatment previously described, it is not expected to have a material impact on the Company's financial statements.

Income Tax Matters

Georgia State Income Tax Credits

The Company's 2005 through 2009 income tax filings for the State of Georgia include state income tax credits for increased activity through Georgia ports. The Company filed similar claims for the years 2002 through 2004. The Georgia Department of Revenue (DOR) has not responded to these claims. In July 2007, the Company filed a complaint in the Superior Court of Fulton County to recover the credits claimed for the years 2002 through 2004. On March 22, 2010, the Superior Court of Fulton County ruled in favor of the Company's motion for summary judgment. The Georgia DOR has appealed to the Georgia Court of Appeals and a decision is expected later this year. Any decision may be subject to further appeal to the Georgia Supreme Court. An unrecognized tax benefit has been recorded related to these credits. If the Company prevails, no material impact on the Company's net income is expected as a significant portion of any tax benefit is expected to be returned to retail customers in accordance with the 2010 ARP. If the Company is not successful, payment of the related state tax could have a significant, and possibly material, negative effect on the Company's cash flow. See Note 5 under "Unrecognized Tax Benefits" for additional information. The ultimate outcome of this matter cannot be determined at this time.

Tax Method of Accounting for Repairs

The Company submitted a change in the tax accounting method for repair costs associated with the Company's generation, transmission, and distribution systems with the filing of the 2009 federal income tax return in September 2010. The new tax method resulted in net positive cash flow in 2010 of approximately $133 million for the Company. Although IRS approval of this change is considered automatic, the amount claimed is subject to review because the IRS will be issuing final guidance on this matter. Currently, the IRS is working with the utility industry in an effort to resolve this matter in a consistent manner for all utilities. Due to uncertainty concerning the ultimate resolution of this matter, an unrecognized tax benefit has been recorded for the change in the tax accounting method for repair costs. The ultimate outcome of this matter cannot be determined at this time. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Nuclear Fuel Disposal Costs

The Company has contracts with the U.S., acting through 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.

In July 2007, the U.S. Court of Federal Claims awarded the Company approximately $30 million, based on its ownership interests, representing substantially all of the direct costs of the expansion of spent nuclear fuel storage facilities at Plants Hatch and Vogtle from 1998 through 2004. In November 2007, the government's motion for reconsideration was denied. In January 2008, the government filed an appeal and, in February 2008, filed a motion to stay the appeal, which the U.S. Court of Appeals for the Federal Circuit granted in April 2008. On May 5, 2010, the U.S. Court of Appeals for the Federal Circuit lifted the stay.

In April 2008, a second claim against the government was filed for damages incurred after December 31, 2004 (the court-mandated cut-off in the original claim), due to the government's alleged continuing breach of contract. The complaint does not contain any specific dollar amount for recovery of damages. Damages will continue to accumulate until the issue is resolved or the storage is provided. No amounts have been recognized in the financial statements as of December 31, 2010 for either claim. The final outcome of these matters cannot be determined at this time, but no material impact on the Company's net income is expected as any damage amounts collected from the government are expected to be returned to customers.

Sufficient pool storage capacity for spent fuel is available at Plant Vogtle to maintain full-core discharge capability for both units into 2014. 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 spent fuel storage facility is operational and can be expanded to accommodate spent fuel through the expected life of the plant.

Retail Regulatory Matters

Rate Plans

The economic recession significantly reduced the Company's revenues upon which retail rates were set by the Georgia PSC for 2008 through 2010 under the 2007 Retail Rate Plan. In June 2009, despite stringent efforts to reduce expenses, the Company's projected retail return on common equity (ROE) for both 2009 and 2010 was below 10.25%. However, in lieu of filing to increase customer rates as allowed under the 2007 Retail Rate Plan, in June 2009, the Company filed a request with the Georgia PSC for an accounting order that would allow the Company to amortize up to $324 million of its regulatory liability related to other cost of removal obligations.

In August 2009, the Georgia PSC approved the accounting order. Under the terms of the accounting order, the Company could amortize up to $108 million of the regulatory liability in 2009 and up to $216 million in 2010, limited to the amount needed to earn no more than a 9.75% and 10.15% retail ROE in 2009 and 2010, respectively. For the years ended December 31, 2009 and 2010, the Company amortized $41 million and $174 million of the regulatory liability, respectively.

On December 21, 2010, the Georgia PSC approved the 2010 ARP, which became effective January 1, 2011. The terms of the 2010 ARP reflect a settlement agreement among the Company, the Georgia PSC's Public Interest Advocacy Staff (PSC Staff), and eight other intervenors. Under the terms of the 2010 ARP, the Company will amortize approximately $92 million of its remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013.

Also under the terms of the 2010 ARP, effective January 1, 2011, the Company increased its (1) traditional base tariff rates by approximately $347 million; (2) Demand-Side Management (DSM) tariff rates by approximately $31 million; (3) ECCR tariff rate by approximately $168 million; and (4) Municipal Franchise Fee (MFF) tariff rate by approximately $16 million, for a total increase in base revenues of approximately $562 million.

Under the 2010 ARP, the following additional base rate adjustments will be made to the Company's tariffs in 2012 and 2013:

- Effective January 1, 2012, the DSM tariffs will increase by $17 million;
- Effective April 1, 2012, the traditional base tariffs will increase to recover the revenue requirements for the lesser of actual capital costs incurred or the amounts certified by the Georgia PSC for Plant McDonough Units 4 and 5 for the period from commercial operation through December 31, 2013;
- Effective January 1, 2013, the DSM tariffs will increase by $18 million;
- Effective January 1, 2013, the traditional base tariffs will increase to recover the revenue requirements for the lesser of actual capital costs incurred or the amounts certified by the Georgia PSC for Plant McDonough Unit 6 for the period from commercial operation through December 31, 2013; and
- The MFF tariff will increase consistent with these adjustments.

The Company currently estimates these adjustments will result in annualized base revenue increases of approximately $190 million in 2012 and $93 million in 2013.

Under the 2010 ARP, the Company's retail ROE is set at 11.15%, and earnings will be evaluated against a retail ROE range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25 % will be directly refunded to customers, with the remaining one-third retained by the Company. If at any time during the term of the 2010 ARP, the Company projects that retail earnings will be below 10.25% for any calendar year, it may petition the Georgia PSC for the implementation of an Interim Cost Recovery (ICR) tariff to adjust the Company's earnings back to a 10.25% retail ROE. The Georgia PSC will have 90 days to rule on any such request. If approved, any ICR tariff would expire at the earlier of January 1, 2014 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR, the Company may file a full rate case.

Except as provided above, the Company will not file for a general base rate increase while the 2010 ARP is in effect. The Company is required to file a general rate case by July 1, 2013, in response to which the Georgia PSC would be expected to determine whether the 2010 ARP should be continued, modified, or discontinued.

The Company currently expects to file an update to its integrated resource plan in June 2011. Under the terms of the 2010 ARP, any costs associated with changes to the Company's approved environmental operating or capital budgets (resulting from new or revised environmental regulations) through 2013 that are approved by the Georgia PSC in connection with an updated IRP will be deferred as a regulatory asset to be recovered over a time period deemed appropriate by the Georgia PSC. Such costs that may be deferred as a regulatory asset include any impairment losses that may result from a decision to retire certain units that are no longer cost effective in light of new or modified environmental regulations. In addition, in connection with the 2010 ARP, the Georgia PSC also approved revised depreciation rates that will recover the remaining book value of certain of the Company's existing coal-fired units by December 31, 2014. The ultimate outcome of these matters cannot be determined at this time.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved increases in the Company's total annual billings of approximately $222 million effective June 1, 2008 and $373 million effective April 1, 2010. In addition, the Georgia PSC has authorized an interim fuel rider, which would allow the Company to adjust its fuel cost recovery rates prior to the next fuel case if the under recovered fuel balance exceeds budget by more than $75 million. The Company is currently required to file its next fuel case by March 1, 2011.

The Company's under recovered fuel balance totaled approximately $398 million, of which approximately $214 million is included in deferred charges and other assets in the balance sheets at December 31, 2010.

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

Construction

Nuclear

In August 2009, the NRC issued an Early Site Permit and Limited Work Authorization to Southern Nuclear, on behalf of the Company, Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia, an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light, and Sinking Fund Commissioners (collectively, Owners), related to two additional nuclear units on the site of Plant Vogtle (Plant Vogtle Units 3 and 4). See Note 4 for additional information on these co-owners. In March 2008, Southern Nuclear filed an application with the NRC for a combined construction and operating license (COL) for the new units. If licensed by the NRC, Plant Vogtle Units 3 and 4 are scheduled to be placed in service in 2016 and 2017, respectively.

In April 2008, the Company, acting for itself and as agent for the Owners, and a consortium consisting of Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc. (collectively, Consortium) entered into an engineering, procurement, and construction agreement to design, engineer, procure, construct, and test two AP1000 nuclear units with electric generating capacity of approximately 1,100 megawatts each and related facilities, structures, and improvements at Plant Vogtle (Vogtle 3 and 4 Agreement).

The Vogtle 3 and 4 Agreement is an arrangement whereby the Consortium supplies and constructs the entire facility with the exception of certain items provided by the Owners. Under the terms of the Vogtle 3 and 4 Agreement, the Owners agreed to pay a purchase price that will be subject to certain price escalations and adjustments, including fixed escalation amounts and certain index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. Each Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Consortium under the Vogtle 3 and 4 Agreement. The Company's proportionate share is 45.7%.

The Owners and the Consortium have agreed to certain liquidated damages upon the Consortium's failure to comply with the schedule and performance guarantees. The Consortium's liability to the Owners for schedule and performance liquidated damages and warranty claims is subject to a cap.

Certain payment obligations of Westinghouse and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and The Shaw Group, Inc., respectively. In the event of certain credit rating downgrades of any Owner, such Owner will be required to provide a letter of credit or other credit enhancement.

The Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Owners will be required to pay certain termination costs and, at certain stages of the work, cancellation fees to the Consortium. The Consortium may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including delays in receipt of the COL or delivery of full notice to proceed, certain Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Owners, Owner insolvency, and certain other events.

In March 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4. In addition, the Georgia PSC voted to approve the inclusion of the related construction work in progress accounts in rate base. In April 2009, the Governor of the State of Georgia signed into law the Georgia Nuclear Energy Financing Act that allows the Company to recover financing costs for nuclear construction projects by including the related construction work in progress accounts in rate base during the construction period. With respect to Plant Vogtle Units 3 and 4, this legislation allows the Company to recover projected financing costs of approximately $1.7 billion during the construction period beginning in 2011, which reduces the projected in-service cost to approximately $4.4 billion. The Georgia PSC has ordered the Company to report against this total certified cost of approximately $6.1 billion. In addition, on December 21, 2010, the Georgia PSC approved the Company's Nuclear Construction Cost Recovery (NCCR) tariff. The NCCR tariff became effective January 1, 2011 and is expected to collect approximately $223 million in revenues during 2011.

On February 21, 2011, the Georgia PSC voted to approve the Company's third semi-annual construction monitoring report including total costs of $1.048 billion for Plant Vogtle Units 3 and 4 incurred through June 30, 2010. In connection with its certification of Vogtle Units 3 and 4, the Georgia PSC ordered the Company and the PSC Staff to work together to develop a risk sharing or incentive mechanism that would provide some level of protection to ratepayers in the event of significant cost overruns, but also not penalize the Company's earnings if and when overruns are due to mandates from governing agencies. Such discussions have continued through the third semi-annual construction monitoring proceedings; however, the Georgia PSC has deferred a decision with respect to any related incentive or risk-sharing mechanism until a later date. The Company will continue to file construction monitoring reports by February 28 and August 31 of each year during the construction period.

In 2009, the Southern Alliance for Clean Energy (SACE) and the Fulton County Taxpayers Foundation, Inc. (FCTF) filed separate petitions in the Superior Court of Fulton County, Georgia seeking review of the Georgia PSC's certification order and challenging the constitutionality of the Georgia Nuclear Energy Financing Act. On May 5, 2010, the court dismissed as premature the plaintiffs' claim challenging the Georgia Nuclear Energy Financing Act. FCTF appealed the decision, and the Georgia Supreme Court ruled against FCTF, finding the suit premature. In addition, on May 5, 2010, the Superior Court of Fulton County issued an order remanding the Georgia PSC's certification order for inclusion of further findings of fact and conclusions of law by the Georgia PSC. In compliance with the court's order, the Georgia PSC issued its order on remand to include further findings of fact and conclusions of law on June 23, 2010. On July 5, 2010, SACE and FCTF filed separate motions with the Georgia PSC for reconsideration of the order on remand. On August 17, 2010, the Georgia PSC voted to reaffirm its order. The matter is no longer subject to judicial review and is now concluded.

On December 2, 2010, Westinghouse submitted an AP1000 Design Certification Amendment (DCA) to the NRC. On February 10, 2011, the NRC announced that it was seeking public comment on a proposed rule to approve the DCA and amend the certified AP1000 reactor design for use in the U.S. The Advisory Committee on Reactor Safeguards also issued a letter on January 24, 2011 endorsing the issuance of the COL for Plant Vogtle Units 3 and 4. The Company currently expects to receive the COL for Plant Vogtle Units 3 and 4 from the NRC in late 2011 based on the NRC's February 16, 2011 release of its COL schedule framework.

There are other pending technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4. Similar additional challenges at the state and federal level are expected as construction proceeds.

The ultimate outcome of these matters cannot be determined at this time.

Other Construction

On May 6, 2010, the Georgia PSC approved the Company's request to extend the construction schedule for Plant McDonough Units 4, 5, and 6 as a result of the short-term reduction in forecasted demand, as well as the requested increase in the certified amount. As a result, the units are expected to be placed into service in January 2012, May 2012, and January 2013, respectively. To date, the Georgia PSC has approved the Company's quarterly construction monitoring reports including actual project expenditures incurred through June 30, 2010. The Company will continue to file quarterly construction monitoring reports throughout the construction period.

4. JOINT OWNERSHIP AGREEMENTS

The Company and 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 these units is 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 years' notice. The Company accounts for SEGCO using the equity method.

The Company's share of expenses included in purchased power from affiliates in the statements of income is as follows:

	2010	2009	2008
	(in millions)		
Energy	**$ 53**	$ 44	$ 86
Capacity	**47**	43	41
Total	**$ 100**	$ 87	$ 127

The Company owns undivided interests in Plants Vogtle, Hatch, Wansley, and Scherer in varying amounts jointly with OPC, MEAG Power, Dalton, 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 and Florida Power Corporation (Progress Energy Florida) jointly own a combustion turbine unit (Intercession City) operated by Progress Energy Florida.

At December 31, 2010, the Company's percentage ownership and investment (exclusive of nuclear fuel) in jointly owned facilities in commercial operation with the above entities were as follows:

Facility (Type)	Company Ownership	Investment	Accumulated Depreciation
		(in millions)	
Plant Vogtle (nuclear)			
Units 1 and 2	45.7%	$ 3,292	$ 1,935
Plant Hatch (nuclear)	50.1	962	534
Plant Wansley (coal)	53.5	700	208
Plant Scherer (coal)			
Units 1 and 2	8.4	148	74
Unit 3	75.0	857	362
Rocky Mountain (pumped storage)	25.4	175	109
Intercession City (combustion-turbine)	33.3	12	3

At December 31, 2010, the portion of total construction work in progress related to Plants Wansley, Scherer, and Vogtle Units 3 and 4 was $11 million, $110 million, and $1.3 billion, respectively. Construction at Plants Wansley and Scherer relates primarily to environmental projects. See Note 3 under "Construction – Nuclear" for information on Plant Vogtle Units 3 and 4.

The Company's proportionate share of its plant operating expenses is included in the corresponding operating expenses in the statements of income and the Company is responsible for providing its own financing.

5. INCOME TAXES

Southern Company files a consolidated federal income tax return and combined state 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 it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the tax liability.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2010	2009	2008
		(in millions)	
Federal –			
Current	**$ 147**	$ 211	$ 284
Deferred	**312**	175	155
	459	386	439
State –			
Current	**(36)**	7	33
Deferred	**30**	17	16
	(6)	24	49
Total	**$ 453**	$ 410	$ 488

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:

	2010	2009
	(in millions)	
Deferred tax liabilities –		
Accelerated depreciation	**$ 3,184**	$ 2,923
Property basis differences	**746**	585
Employee benefit obligations	**251**	184
Fuel clause under recovery	**162**	270
Premium on reacquired debt	**71**	64
Emissions allowances	**18**	22
Regulatory assets associated with employee benefit obligations	**336**	362
Asset retirement obligations	**275**	263
Other	**52**	70
Total	**5,095**	4,743
Deferred tax assets –		
Federal effect of state deferred taxes	**159**	177
Employee benefit obligations	**433**	482
Other property basis differences	**111**	117
Other deferred costs	**72**	65
Cost of removal obligations	**52**	109
State tax credit carry forward	**192**	99
Other comprehensive income	**6**	12
Unbilled fuel revenue	**57**	42
Asset retirement obligations	**275**	263
Environmental capital cost recovery	**1**	37
Other	**37**	38
Total	**1,395**	1,441
Total deferred tax liabilities, net	**3,700**	3,302
Portion included in current assets/(liabilities), net	**18**	88
Accumulated deferred income taxes	**$ 3,718**	$ 3,390

At December 31, 2010, tax-related regulatory assets were $727 million and tax-related regulatory liabilities were $129 million. These assets are attributable to tax benefits flowed through to customers in prior years, to deferred taxes previously recognized at rates lower than the current enacted tax law, and to taxes applicable to capitalized interest. In 2010, the Company deferred $51 million as a regulatory asset related to the impact of the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 (together, the Acts). The Acts eliminated the deductibility of health care costs that are covered by federal Medicare subsidy payments. Beginning in 2011, the Company is amortizing the regulatory asset to income tax expense over 12 years, under the 2010 ARP. These liabilities are attributable to deferred taxes previously recognized at rates higher than current enacted tax law and to unamortized investment tax credits.

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 $13 million in 2010, $14 million in 2009, and $13 million in 2008. At December 31, 2010, all investment tax credits available to reduce federal income taxes payable had been utilized.

On September 27, 2010, the Small Business Jobs and Credit Act of 2010 (SBJCA) was signed into law. The SBJCA includes an extension of the 50% bonus depreciation for certain property acquired and placed in service in 2010 (and for certain long-term construction projects to be placed in service in 2011). Additionally, on December 17, 2010, the Tax Relief, Unemployment Insurance

Reauthorization, and Job Creation Act (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term construction projects to be placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term construction projects to be placed in service in 2013). The application of the bonus depreciation provisions in these acts in 2010 significantly increased deferred tax liabilities related to accelerated depreciation.

Effective Tax Rate

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

	2010	2009	2008
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**(0.3)**	1.2	2.2
Non-deductible book depreciation	**1.0**	1.1	0.9
AFUDC equity	**(3.6)**	(2.7)	(2.4)
Donations	**-**	(0.8)	-
Other	**(0.2)**	(0.8)	(1.1)
Effective income tax rate	**31.9%**	33.0%	34.6%

The decreases in the Company's 2010 and 2009 effective tax rates are primarily the result of increases in non-taxable AFUDC equity and state tax credits. See "Unrecognized Tax Benefits" herein and Note 3 under "Income Tax Matters" for additional information on unrecognized tax benefits and related litigation related to state tax credits.

The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in Section 199 of the Internal Revenue Code. The deduction is equal to a stated percentage of qualified production activities net income. The percentage was phased in over the years 2005 through 2010. For 2008 and 2009, a 6% reduction was available to the Company. Thereafter, the allowed rate is 9%; however, due to increased tax deductions from bonus depreciation and pension contributions there was no domestic production deduction available to the Company for 2010.

Unrecognized Tax Benefits

For 2010, the total amount of unrecognized tax benefits increased by $56 million, resulting in a balance of $237 million as of December 31, 2010.

Changes during the year in unrecognized tax benefits were as follows:

	2010	2009	2008
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ 181**	$ 137	$ 89
Tax positions from current periods	**52**	44	47
Tax positions increase from prior periods	**27**	6	5
Tax positions decrease from prior periods	**(23)**	(5)	-
Reductions due to settlements	**-**	-	(4)
Reductions due to expired statute of limitations	**-**	(1)	-
Balance at end of year	**$ 237**	$ 181	$ 137

The tax positions from current periods relates primarily to the Georgia state tax credits litigation, tax accounting method change for repairs and other miscellaneous uncertain tax positions. The tax positions increase from prior periods relates primarily to the tax accounting method change for repairs and other miscellaneous positions. The tax positions decrease from prior periods relates primarily to the Georgia state tax credit litigation and miscellaneous tax positions. See Note 3 under "Income Tax Matters" for additional information.

The impact on the Company's effective tax rate, if recognized, is as follows:

	2010	2009	2008
		(in millions)	
Tax positions impacting the effective tax rate	$ 202	$ 181	$ 134
Tax positions not impacting the effective tax rate	35	-	3
Balance of unrecognized tax benefits	$ 237	$ 181	$ 137

The tax positions impacting the effective tax rate primarily relate to the state tax credit litigation, however, as discussed in Note 3 under "Income Tax Matters," if the Company is successful in its claim against the DOR, a significant portion of the tax benefit is expected to be deferred and returned to retail customers and therefore no material impact to net income is expected. The tax positions not impacting the effective tax rate relate to the timing difference associated with the tax accounting method change for repairs. These amounts are presented on a gross basis without considering the related federal or state income tax impact. See Note 3 under "Income Tax Matters" for additional information.

Accrued interest for unrecognized tax benefits was as follows:

	2010	2009	2008
		(in millions)	
Interest accrued at beginning of year	$ 20	$ 14	$ 7
Interest accrued during the year	7	6	7
Balance at end of year	$ 27	$ 20	$ 14

The Company classifies interest on tax uncertainties as interest expense. The net amount of interest accrued for all years presented was primarily associated with the state tax credit litigation. The Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits associated with a majority of the Company's unrecognized tax positions will significantly increase or decrease within the next 12 months. The resolution of the state tax credit litigation would substantially reduce the balances. The conclusion or settlement of state audits could also impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has audited and closed all tax returns prior to 2007. The audits for the state returns have either been concluded, or the statute of limitations has expired, for years prior to 2006.

6. FINANCING

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 $206 million, which constitute substantially all of the assets of these trusts and are reflected in the balance sheets as long-term debt. 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, 2010, preferred securities of $200 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 was as follows:

	2010	2009
	(in millions)	
Capital lease	$ 4	$ 4
Bank term loan	300	-
Pollution control revenue bonds	8	-
Senior notes	100	250
Other long-term debt	3	-
Total	$ 415	$ 254

Maturities through 2015 applicable to total long-term debt are as follows: $415 million in 2011; $205 million in 2012; $1.4 billion in 2013; $5 million in 2014; and $256 million in 2015.

Pollution Control Revenue 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, 2010 and 2009 was $1.5 billion and $2.0 billion, respectively. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

Senior Notes

The Company issued $2.0 billion aggregate principal amount of unsecured senior notes in 2010. The proceeds of the issuance were used to repay a portion of the Company's short-term indebtedness, fund note redemptions totaling $1.1 billion, redeem pollution control revenue bonds totaling $516 million, and fund the Company's continuous construction program.

At December 31, 2010 and 2009, the Company had $6.3 billion and $5.4 billion of senior notes outstanding, respectively. These senior notes are effectively subordinated to all secured debt of the Company, which aggregated $59 million and $63 million at December 31, 2010 and 2009, respectively.

Subsequent to December 31, 2010, the Company issued $300 million of Series 2011A Floating Rate Senior Notes due January 15, 2013. The proceeds from the sale of the Series 2011A Senior Notes were used by the Company to repay a portion of its outstanding short-term indebtedness and for general corporate purposes, including the Company's continuous construction program.

Bank Term Loans

At December 31, 2010 and 2009, the Company had a $300 million bank loan outstanding, which matures in March 2011.

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, 2010 and 2009, the Company had a capitalized lease obligation for its corporate headquarters building of $58 million and $62 million, respectively, with an interest rate of 8.0%. 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." The annual expense incurred for all capital leases in 2010, 2009, and 2008 was $6 million, $9 million, and $10 million, respectively.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company has shares of its Class A preferred stock, preference stock, and common stock outstanding. The Company's Class A preferred stock ranks senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. Certain series of the Class A preferred stock and preference stock are subject to redemption at the option of the Company on or after a specified date (typically five or 10 years after the date of issuance) at a redemption price equal to 100% of the liquidation amount of the stock. In addition, the Company may redeem the outstanding series of the preference stock at a redemption price equal to 100% of the liquidation amount plus a make-whole premium based on the present value of the liquidation amount and future dividends through the first par redemption date.

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Bank Credit Arrangements

At December 31, 2010, the Company had credit arrangements with banks totaling $1.7 billion, of which $12 million was used to support outstanding letters of credit. Of these facilities, $595 million expire during 2011, with the remaining $1.1 billion expiring in 2012. Of the facilities that expire in 2011, $40 million provides the option of converting borrowings into a two-year term loan and $220 million provides the option of converting borrowings into a one-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 average less than 1/4 of 1% for the Company. Compensating balances are not legally restricted from withdrawal.
The credit arrangements contain covenants that limit the ratio of indebtedness to capitalization (each as defined in the arrangements) to 65%. For purposes of these definitions, indebtedness excludes the long-term debt payable to affiliated trusts and, in certain cases, other hybrid securities. 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, 2010, the Company was in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowings.

The $1.7 billion of unused credit arrangements provides liquidity support to the Company's variable rate pollution control revenue bonds and its commercial paper borrowings. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2010 was $385 million. Subsequent to December 31, 2010, the Company's remarketing of $137 million of variable rate pollution control revenue bonds increased the total requiring liquidity support to $522 million. In addition, the Company borrows under a commercial paper program. The amount of commercial paper outstanding at December 31, 2010 and 2009 was $575 million and $324 million, respectively. Commercial paper and short-term bank loans are included in notes payable on the balance sheets.

During 2010, the maximum amount of commercial paper outstanding was $575 million and the average amount outstanding was $167 million. During 2009, the maximum amount of commercial paper outstanding was $757 million and the average amount outstanding was $348 million. The weighted average annual interest rate on commercial paper in 2010 and 2009 was 0.3% and 0.4%, respectively.

7. COMMITMENTS

Construction Program

The construction program of the Company is currently estimated to include a base level investment of $2.1 billion, $2.2 billion, and $2.0 billion for 2011, 2012, and 2013, respectively. These amounts include $252 million, $148 million, and $185 million in 2011, 2012, and 2013, respectively, for construction expenditures related to contractual purchase commitments for nuclear fuel included herein under "Fuel Commitments." Included in these estimated amounts are environmental expenditures to comply with existing statutes and regulations of $73 million, $79 million, and $58 million for 2011, 2012, and 2013, respectively. The capital budget amounts for 2011-2013 include amounts for the construction of Plant Vogtle Units 3 and 4 as discussed in Note 3 under "Construction – Nuclear." Of the estimated total $4.4 billion in capital costs, approximately $943 million is expected to be incurred from 2014 through 2017. The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; changes in generating plants, including unit retirements and replacements, to meet new regulatory requirements; changes in FERC rules and regulations; Georgia PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. At December 31, 2010, significant purchase commitments were outstanding in connection with the ongoing construction program. See Note 3 under "Construction" for additional information.

Long-Term Service Agreements

The Company has a long-term service agreement (LTSA) with General Electric (GE) for 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 the contract. In general, this LTSA is in effect through two major inspection cycles per unit. Scheduled payments to GE, which are subject to price escalation, are made quarterly based on actual operating hours of the respective units. Total payments to GE are currently estimated at $155 million over the remaining term of the agreement, which is currently projected to be approximately eight years. However, the LTSA contains various cancellation provisions at the option of the Company.

The Company also has a 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 $6 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.

The Company has entered into a LTSA with Mitsubishi Power Systems Americas, Inc. (MPS) for the purpose of providing certain parts and maintenance services for the three combined cycle units under construction at Plant McDonough, which are scheduled to go into service in January 2012, May 2012, and January 2013, respectively. The LTSA stipulates that MPS will perform all planned maintenance on each covered unit which includes the cost of all materials and services. MPS is also obligated to cover costs of unplanned maintenance on the gas turbines subject to limits specified in the LTSA. This LTSA will begin in 2012 and is in effect through two major inspection cycles per covered unit. Periodic payments to MPS are to be made quarterly and will also be made based on the scheduled inspections for the respective covered units. Payments to MPS, which are subject to price escalation, are currently estimated to be $537 million for the term of this agreement which is expected to be between 12 and 13 years. However, the LTSA contains various termination provisions at the option of the Company.

Limestone Commitments

As part of the Company's program to reduce sulfur dioxide emissions from its coal plants, the Company has entered into various long-term commitments for the procurement of limestone to be used in flue gas desulfurization equipment. Limestone contracts are structured with tonnage minimums and maximums in order to account for fluctuations in coal burn and sulfur content. The Company has a minimum contractual obligation of 3.5 million tons, equating to approximately $93 million through 2019. Estimated expenditures (based on minimum contracted obligated dollars) over the next five years are $17 million in 2011, $18 million in 2012, $18 million in 2013, $19 million in 2014, and $11 million in 2015.

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 emissions 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, 2010.

Total estimated minimum long-term commitments at December 31, 2010 were as follows:

	Commitments		
	Natural Gas	Coal	Nuclear Fuel
		(in millions)	
2011	$ 445	$ 1,869	$ 252
2012	490	808	148
2013	494	730	185
2014	429	441	165
2015	340	345	98
2016 and thereafter	2,665	1,182	585
Total	$4,863	$ 5,375	$ 1,433

Additional commitments for fuel will be required to supply the Company's future needs. Total charges for nuclear fuel included in fuel expense amounted to $106 million, $82 million, and $77 million for the years 2010, 2009, and 2008, respectively.

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 traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. The creditworthiness of Southern Power is currently inferior to the creditworthiness of the traditional operating companies. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Purchased Power Commitments

The Company has commitments regarding a portion of a 5% interest in Plant Vogtle owned by MEAG Power that are in effect until the latter of the retirement of the plant or the latest stated maturity date of MEAG Power'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. Portions of the capacity payments 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. Generally, the cost of such capacity and energy is included in purchased power, non-affiliates in the statements of income. Capacity payments totaled $55 million, $54 million, and $48 million in 2010, 2009, and 2008, respectively. The Company also has entered into other various long-term PPAs. Estimated total long-term obligations under these commitments at December 31, 2010 were as follows:

	Vogtle Capacity Payments	Affiliated PPAs	Non-Affiliated PPAs
		(in millions)	
2011	$ 55	$ 119	$ 142
2012	49	107	115
2013	23	107	108
2014	18	108	109
2015	11	108	110
2016 and thereafter	87	380	1,259
Total	$ 243	$ 929	$ 1,843

Certain PPAs reflected in the table are accounted for as operating leases.

Operating Leases

The Company has entered into various operating leases with various terms and expiration dates. Rental expenses related to these operating leases totaled $35 million for 2010, $43 million for 2009, and $52 million for 2008.

At December 31, 2010, estimated minimum lease payments for noncancelable operating leases were as follows:

	Minimum Lease Payments		
	Rail Cars	Other	Total
		(in millions)	
2011	$ 30	$ 6	$ 36
2012	17	4	21
2013	12	4	16
2014	10	3	13
2015	8	1	9
2016 and thereafter	7	1	8
Total	$ 84	$ 19	$ 103

In addition to the above rental commitments, 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 $40 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. A portion of the rail car lease obligations is shared with the joint owners of Plants Scherer and Wansley. A majority of the rental expenses related to the rail car leases are fully recoverable through the fuel cost recovery clause as ordered by the Georgia PSC and the remaining portion is recovered through base rates. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligations.

Guarantees

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 $25 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 COMPENSATION

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, 2010, there were 1,837 current and former employees of the Company participating in the stock option plan, and there were 10 million shares of Southern Company common stock remaining available for awards under this plan and the Performance Share Plan discussed below. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement the total cost is expensed at the grant date. 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. For certain stock option awards, a change in control will provide accelerated vesting.

The estimated fair values of stock options granted in 2010, 2009, and 2008 were derived using the Black-Scholes stock option pricing model. Expected volatility was based on historical volatility of Southern Company's stock over a period equal to the expected term. Southern Company used historical exercise data to estimate the expected term that represents the period of time that options granted to employees are expected to be outstanding. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the expected term of the stock options.

The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of stock options granted:

Year Ended December 31	**2010**	2009	2008
Expected volatility	**17.4%**	15.6%	13.1%
Expected term *(in years)*	**5.0**	5.0	5.0
Interest rate	**2.4%**	1.9%	2.8%
Dividend yield	**5.6%**	5.4%	4.5%
Weighted average grant-date fair value	**$2.23**	$1.80	$2.37

The Company's activity in the stock option plan for 2010 is summarized below:

	Shares Subject to Option	**Weighted Average Exercise Price**
Outstanding at December 31, 2009	10,322,924	$31.90
Granted	1,715,600	31.19
Exercised	(1,656,754)	27.80
Cancelled	163	30.34
Outstanding at December 31, 2010	**10,381,933**	**$32.44**
Exercisable at December 31, 2010	**6,848,412**	**$32.77**

The number of stock options vested, and expected to vest in the future, as of December 31, 2010 was not significantly different from the number of stock options outstanding at December 31, 2010 as stated above. At December 31, 2010, the weighted average remaining contractual term for the options outstanding and options exercisable was approximately six years and five years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $60 million and $37 million, respectively. As of December 31, 2010, the amount of unrecognized compensation cost related to stock option awards not yet vested was immaterial.

The compensation cost and tax benefits related to the grant and exercise of Southern Company stock options to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. The amounts were not material for any year presented.

The total intrinsic value of options exercised during the years ended December 31, 2010, 2009, and 2008 was $12 million, $2 million, and $11 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises was not material for any year presented.

Performance Share Plan

In 2010, Southern Company implemented the performance share program under its omnibus incentive compensation plan, which provides performance share award units to a large segment of the Company's employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three-year performance period which equates to the requisite service period. Employees that retire prior to the end of the three-year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three-year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount.

The fair value of performance share awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period. The Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. Expected volatility used in the model of 20.7% was based on historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate of 1.4% was based on the U.S. Treasury yield curve in effect at the time of grant that covers the performance period of the award units. The annualized dividend rate at the time of the grant was $1.75. During 2010, 189,361 performance share units were granted to the Company's employees with a weighted-average grant date fair value of $30.13. During 2010, 3,849 performance share units were forfeited by the Company's employees resulting in 185,512 unvested units outstanding at December 31, 2010.

For the year ended December 31, 2010, the Company's total compensation cost for performance share units and the related tax benefit recognized in income were not material. As of December 31, 2010, the amount of total unrecognized compensation cost related to performance share award units that will be recognized over the next two years was not material.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (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 Plants Hatch and Vogtle. The Act provides funds up to $12.6 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 $375 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 commercial nuclear reactors. The Company could be assessed up to $117.5 million per incident for each licensed reactor it operates but not more than an aggregate of $17.5 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for the Company, based on its ownership and buyback interests, is $237 million, per incident, but not more than an aggregate of $35 million to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due no later than October 29, 2013.

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

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After 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. Each facility has elected a 12-week deductible waiting period.

A builders' risk property insurance policy has been purchased from NEIL for the construction of Plant Vogtle Units 3 and 4. This policy provides the Owners up to $2.75 billion for accidental property damage occurring during construction.

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 $70 million.

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12-month period is $3.2 billion plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

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 debt 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. In the event of a loss, the amount of insurance available may not be adequate to cover property damage and other incurred expenses.

10. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

As of December 31, 2010, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2010:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Energy-related derivatives	$ -	$ 1	$ -	$ 1
Nuclear decommissioning trusts:[(a)]				
Domestic equity	257	1	-	258
U.S. Treasury and government agency securities	-	213	-	213
Municipal bonds	-	53	-	53
Corporate bonds	-	138	-	138
Mortgage and asset backed securities	-	89	-	89
Other	-	67	-	67
Total	$ 257	$ 562	$ -	$ 819
Liabilities:				
Energy-related derivatives	$ -	$ 101	$ -	$ 101

(a) Includes the investment securities pledged to creditors and collateral received, and excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases and the lending pool. See Note 1 under "Nuclear Decommissioning" for additional information.

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, implied volatility, and London Interbank Offered Rate (LIBOR) interest rates. See Note 11 for additional information on how these derivatives are used.

For fair value measurements of investments within the nuclear decommissioning trusts, specifically the fixed income assets using significant other observable inputs and unobservable inputs, the primary valuation technique used is the market approach. External pricing vendors are designated for each of the asset classes in the nuclear decommissioning trusts with each security discriminately assigned a primary pricing source, based on similar characteristics.

A market price secured from the primary source vendor is then used in the valuation of the assets within the trusts. As a general approach, market pricing vendors gather market data (including indices and market research reports) and integrate relative credit information, observed market movements, and sector news into proprietary pricing models, pricing systems, and mathematical tools. Dealer quotes and other market information including live trading levels and pricing analysts' judgment are also obtained when available.

As of December 31, 2010, the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

As of December 31, 2010:	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
	(in millions)			
Nuclear decommissioning trusts:				
Corporate bonds – commingled funds	$ 65	None	Daily	1 to 3 days
Other – commingled funds	$ 67	None	Daily	Not applicable

The commingled funds in the nuclear decommissioning trusts are invested primarily in a diversified portfolio of high grade money market instruments, including, but not limited to, commercial paper, notes, repurchase agreements, and other evidences of indebtedness with a maturity not exceeding 13 months from the date of purchase. The commingled funds will, however, maintain a dollar-weighted average portfolio maturity of 90 days or less. The assets may be longer term investment grade fixed income obligations having a maximum five-year final maturity with put features or floating rates with a reset date of 13 months or less. The primary objective for the commingled funds is a high level of current income consistent with stability of principal and liquidity. The corporate bonds – commingled funds represent the investment of cash collateral received under the Funds' managers' securities lending program that can only be sold upon the return of the loaned securities. See Note 1 under "Nuclear Decommissioning" for additional information.

As of December 31, 2010 and 2009, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2010	**$ 8,285**	**$ 8,548**
2009	$ 7,973	$ 8,059

The fair values were based on either closing market prices (Level 1) or closing prices of comparable instruments (Level 2).

11. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities.

Energy-Related Derivatives

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 and other various cost recovery mechanisms, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages fuel-hedging programs, implemented per the guidelines of the Georgia PSC, through the use of financial derivative contracts, and recently has started using significantly more financial options within the guidelines of the Georgia PSC which is expected to continue to mitigate price volatility.

To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in one of two methods:

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the fuel cost recovery clauses.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2010, the net volume of energy-related derivative contracts for natural gas positions totaled 59 million mmBtu (million British thermal units), all of which expire by 2015, which is the longest hedge date.

In addition to the volume discussed above, the Company enters into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The expected volume of natural gas subject to such a feature is 4 million mmBtu for the Company.

Interest Rate Derivatives

The Company also enters into interest rate derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to income.

At December 31, 2010, there were no interest rate derivatives outstanding.

The estimated pre-tax losses that will be reclassified from OCI to interest expense for the next 12-month period ending December 31, 2011 are $4 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2037.

Derivative Financial Statement Presentation and Amounts

At December 31, 2010 and 2009, the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2010**	2009	**Balance Sheet Location**	**2010**	2009
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$1**	$-	Liabilities from risk management activities	**$77**	$47
	Other deferred charges and assets	**-**	-	Other deferred credits and liabilities	**24**	28
Total derivatives designated as hedging instruments for regulatory purposes		**$1**	$-		**$101**	$75
Derivatives designated as hedging instruments in cash flow hedges						
Interest rate derivatives:	Other current assets	**$-**	$-	Liabilities from risk management activities	**$-**	$2
Total		**$1**	$-		**$101**	$77

All derivative instruments are measured at fair value. See Note 10 for additional information.

At December 31, 2010 and 2009, the pre-tax effect of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets was as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2010**	2009	**Balance Sheet Location**	**2010**	2009
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$(77)**	$(47)	Other regulatory liabilities, current	**$1**	$-
	Other regulatory assets, deferred	**(24)**	(28)	Other deferred credits and liabilities	**-**	-
Total energy-related derivative gains (losses)		**$(101)**	$(75)		**$1**	$-

For the years ended December 31, 2010, 2009, and 2008, the pre-tax effect of interest rate derivatives designated as cash flow hedging instruments on the statements of income was as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)			Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
					Amount		
Derivative Category	**2010**	2009	2008	**Statements of Income Location**	**2010**	2009	2008
		(in millions)				*(in millions)*	
Interest rate derivatives	**$ -**	$(3)	$(34)	Interest expense, net of amounts capitalized	**$(16)**	$(22)	$(3)

There was no material ineffectiveness recorded in earnings for any period presented.

For the years ended December 31, 2010, 2009, and 2008, the pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was not material.

Contingent Features

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. The Company has certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2010, the fair value of derivative liabilities with contingent features was $26 million.

At December 31, 2010, the Company had no collateral posted with its derivative counterparties; however, because of the joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, is $40 million.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. The Company participates in certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2010 and 2009 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
		(in millions)	
March 2010	**$ 1,984**	**$ 399**	**$ 238**
June 2010	**2,000**	**411**	**238**
September 2010	**2,628**	**714**	**420**
December 2010	**1,737**	**141**	**54**
March 2009	$ 1,766	$ 272	$ 122
June 2009	1,874	369	190
September 2009	2,327	683	388
December 2009	1,725	206	114

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

SELECTED FINANCIAL AND OPERATING DATA 2006-2010
Georgia Power Company 2010 Annual Report

	2010	2009	2008	2007	2006
Operating Revenues (in millions)	**$8,349**	$7,692	$8,412	$7,572	$7,246
Net Income after Dividends on Preferred and Preference Stock (in millions)	**$950**	$814	$903	$836	$787
Cash Dividends on Common Stock (in millions)	**$820**	$739	$721	$690	$630
Return on Average Common Equity (percent)	**11.42**	11.01	13.56	13.50	13.80
Total Assets (in millions)	**$25,914**	$24,295	$22,316	$20,823	$19,309
Gross Property Additions (in millions)	**$2,401**	$2,646	$1,953	$1,862	$1,277
Capitalization (in millions):					
Common stock equity	**$8,741**	$7,903	$6,879	$6,435	$5,956
Preferred and preference stock	**266**	266	266	266	45
Long-term debt	**7,931**	7,782	7,006	5,938	5,212
Total (excluding amounts due within one year)	**$16,938**	$15,951	$14,151	$12,639	$11,213
Capitalization Ratios (percent):					
Common stock equity	**51.6**	49.5	48.6	50.9	53.1
Preferred and preference stock	**1.6**	1.7	1.9	2.1	0.4
Long-term debt	**46.8**	48.8	49.5	47.0	46.5
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**2,049,770**	2,043,661	2,039,503	2,024,520	1,998,643
Commercial	**296,140**	295,375	295,925	295,478	294,654
Industrial	**8,136**	8,202	8,248	8,240	8,008
Other	**7,309**	6,580	5,566	4,807	4,371
Total	**2,361,355**	2,353,818	2,349,242	2,333,045	2,305,676
Employees (year-end)	**8,330**	8,599	9,337	9,270	9,278

N/A = Not Applicable.

SELECTED FINANCIAL AND OPERATING DATA 2006-2010 (continued)
Georgia Power Company 2010 Annual Report

	2010	2009	2008	2007	2006
Operating Revenues (in millions):					
Residential	**$ 3,072**	$2,686	$2,648	$2,443	$2,326
Commercial	**3,011**	2,826	2,917	2,576	2,424
Industrial	**1,441**	1,318	1,640	1,404	1,382
Other	**84**	82	81	75	74
Total retail	**7,608**	6,912	7,286	6,498	6,206
Wholesale - non-affiliates	**380**	395	569	538	552
Wholesale - affiliates	**53**	112	286	278	253
Total revenues from sales of electricity	**8,041**	7,419	8,141	7,314	7,011
Other revenues	**308**	273	271	258	235
Total	**$8,349**	$7,692	$8,412	$7,572	$7,246
Kilowatt-Hour Sales (in millions):					
Residential	**29,433**	26,272	26,412	26,840	26,206
Commercial	**33,855**	32,593	33,058	33,057	32,112
Industrial	**23,209**	21,810	24,164	25,490	25,577
Other	**663**	671	671	697	660
Total retail	**87,160**	81,346	84,305	86,084	84,555
Wholesale - non-affiliates	**4,662**	5,208	9,755	10,578	10,687
Wholesale - affiliates	**1,000**	2,504	3,695	5,192	5,463
Total	**92,822**	89,058	97,755	101,854	100,705
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**10.44**	10.22	10.03	9.10	8.88
Commercial	**8.89**	8.67	8.82	7.79	7.55
Industrial	**6.21**	6.04	6.79	5.51	5.40
Total retail	**8.73**	8.50	8.64	7.55	7.34
Wholesale	**7.65**	6.57	6.36	5.17	4.98
Total sales	**8.66**	8.33	8.33	7.18	6.96
Residential Average Annual Kilowatt-Hour Use Per Customer	**14,367**	12,848	12,969	13,315	13,216
Residential Average Annual Revenue Per Customer	**$1,499**	$1,314	$1,300	$1,212	$1,173
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**15,992**	15,995	15,995	15,995	15,995
Maximum Peak-Hour Demand (megawatts):					
Winter	**15,614**	15,173	14,221	13,817	13,528
Summer	**17,152**	16,080	17,270	17,974	17,159
Annual Load Factor (percent)	**60.9**	60.7	58.4	57.5	61.8
Plant Availability (percent):					
Fossil-steam	**88.6**	92.5	91.0	90.8	91.4
Nuclear	**94.0**	88.4	89.8	92.4	90.7
Source of Energy Supply (percent):					
Coal	**51.8**	52.3	58.7	61.5	59.0
Nuclear	**16.4**	16.2	14.8	14.6	14.4
Hydro	**1.4**	1.8	0.6	0.5	0.9
Oil and gas	**8.0**	7.7	5.1	5.5	5.0
Purchased power -					
From non-affiliates	**5.2**	4.4	5.1	3.8	3.8
From affiliates	**17.2**	17.6	15.7	14.1	16.9
Total	**100.0**	100.0	100.0	100.0	100.0

DIRECTORS AND OFFICERS
Georgia Power Company 2010 Annual Report

Directors

W. Paul Bowers (Elected Effective 1/1/2011)
President and Chief Executive Officer
Georgia Power Company

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

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

Thomas A. Fanning (Elected Effective 12/1/2010)
Chairman, President, and Chief Executive Officer
The Southern Company

Michael D. Garrett (Retired Effective 12/31/2010)
President and Chief Executive Officer
Georgia Power Company

Stephen S. Green
President and Chief Executive Officer
Stephen Green Properties, Inc.

David M. Ratcliffe (Retired Effective 12/1/2010)
Chairman, President, and Chief Executive Officer
The Southern Company

Jimmy C. Tallent
President and Chief Executive Officer
United Community Banks, Inc.

Charles K. Tarbutton (Elected Effective 8/18/2010)
Assistant Vice President
Sandersville Railroad Company

Beverly Daniel Tatum
President
Spelman College

D. Gary Thompson
Retired (12/2004)
(Wachovia Corporation)

Richard W. Ussery
Retired (7/2006)
(Total System Services, Inc.)

W. Jerry Vereen (Retired Effective 9/7/2010)
Chairman, President, and Chief Executive Officer
Riverside Manufacturing Company & Subsidiaries

E. Jenner Wood III
Chairman, President, and Chief Executive Officer
SunTrust Bank, Atlanta/Georgia Division

Officers

W. Paul Bowers (Elected Effective 1/1/2011)
President and Chief Executive Officer
Georgia Power Company

Michael D. Garrett (Retired Effective 12/31/2010)
President and Chief Executive Officer
Georgia Power Company

W. Craig Barrs
Executive Vice President
External Affairs

Mickey A. Brown
Executive Vice President
Customer Service Organization

Ronnie R. Labrato
Executive Vice President, Chief Financial Officer,
and Treasurer

Joseph A. (Buzz) Miller
Executive Vice President
Nuclear Development

Michael K. Anderson (Elected Effective 1/8/2011)
Senior Vice President
Charitable Giving

Thomas P. Bishop
Senior Vice President, Compliance Officer,
and General Counsel

Stan W. Connally (Elected Effective 8/1/2010)
Senior Vice President
Fossil & Hydro Generation and
Senior Production Officer

Richard L. Holmes
Senior Vice President
Metro Region

Douglas E. Jones (Resigned Effective 8/5/2010)
Senior Vice President
Fossil & Hydro Generation and
Senior Production Officer

DIRECTORS AND OFFICERS

Christopher T. Bell (Elected Effective 7/7/2010)
Vice President
Energy Planning & Sales

Rebecca A. Blalock
Vice President
Information Resources

Melissa K. Caen
Assistant Secretary

Moanica M. Caston (Elected Effective 1/8/2011)
Vice President
Diversity

P. Mike Clanton
Vice President
Energy Sales and Efficiency

Jason T. Cuevas (Elected Effective 2/5/2011)
Vice President
Corporate Communication

Ann P. Daiss
Vice President, Comptroller, and Chief Accounting Officer

Walter Dukes
Vice President
Land

J. Truitt Eavenson (Elected Effective 5/1/2010)
Region Vice President
East

A. Bryan Fletcher
Vice President
Supply Chain Management

J. Kevin Fletcher
Vice President
Community and Economic Development

Jim R. Fletcher (Elected Effective 1/8/2011)
Vice President
Regulatory Affairs

Jeff G. Franklin
Vice President
Governmental Affairs

Oscar C. Harper IV (Resigned Effective 6/29/2010)
Vice President
Energy Planning and Nuclear Development

O. Ben Harris (Retired Effective 7/1/2010)
Vice President
Land

Michael A. Hazelton (Elected Effective 1/8/2011)
Region Vice President
Northeast

Cathy P. Hill
Region Vice President
Coastal

Charles H. Huling (Retired Effective 12/31/2010)
Vice President
Environmental Affairs

Gerald L. Johnson (Elected Effective 3/1/10)
Vice President
Customer Services

Marsha S. Johnson (Retired Effective 9/1/2010)
Vice President
Human Resources

Anne H. Kaiser
Region Vice President
Northwest

Stacy R. Kilcoyne (Elected Effective 11/17/2010)
Vice President
Human Resources

Earl C. Long
Assistant Treasurer

Jacki W. Lowe
Region Vice President
West

Daniel M. Lowery
Corporate Secretary

Terri H. Lupo
Region Vice President
South

Frank J. McCloskey (Retired Effective 12/31/2010)
Vice President
Diversity

Robert B. Morris
Assistant Comptroller and Assistant Secretary

Laura I. Patterson (Elected Effective 3/1/10)
Assistant Comptroller

Ronald Shipman (Elected Effective 1/8/2011)
Vice President
Environmental Affairs

Leslie R. Sibert
Vice President
Distribution

James E. Sykes, Jr. (Retired Effective 12/31/2010)
Region Vice President
Northeast

Mark K. Tate (Resigned Effective 3/1/10)
Assistant Comptroller

Thomas J. Wicker
Region Vice President
Central

Anthony L. Wilson
Vice President
Transmission

W. Tal Wright (Resigned Effective 2/5/2011)
Vice President
Corporate Communication

James D. Wynn, Jr. (Elected Effective 1/8/2011)
Vice President
Corporate Services

CORPORATE INFORMATION
Georgia Power Company 2010 Annual Report

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

Profile
The Company produces and delivers electricity as an integrated utility to retail customers within the State of Georgia and to wholesale customers in the Southeast. The Company sells electricity to approximately 2.4 million customers within its service area. In 2010, retail energy sales accounted for 94% of the Company's total sales of 92.8 billion kilowatt-hours.

The Company is a wholly owned subsidiary of The Southern Company, which is the parent company of four traditional operating companies, a wholesale generation subsidiary, and other direct and indirect subsidiaries.

Trustee, Registrar, and Interest Paying Agent
All series of Senior Notes and Trust Preferred Securities
The Bank of New York Mellon
101 Barclay Street, 8 West
New York, New York 10286

Registrar, Transfer Agent, and Dividend Paying Agent
For Preferred Stock and Preference Stock
BNY Mellon Shareowner Services
480 Washington Boulevard
Jersey City, NJ 07310-1900
(800) 554-7626

www.bnymellon.com/shareowner/equityaccess

There is no market for the Company's common stock, all of which is owned by Southern Company.

Dividends on the Company's common stock are payable at the discretion of the Company's board of directors. The dividends declared by the Company to its common stockholder for the past two years were as follows:

Quarter	2010	2009
	(in thousands)	
First	$205,000	$184,725
Second	205,000	184,725
Third	205,000	184,725
Fourth	205,000	184,725

All of the outstanding shares of the Company's preferred and preference stock are registered in the name of Cede & Co., as nominee for The Depository Trust Company.

Form 10-K
A copy of the Form 10-K as filed with the Securities and Exchange Commission will be provided without charge upon written request to the office of the Corporate Secretary. Requests for copies should be directed to the Corporate Secretary, 241 Ralph McGill Boulevard, N.E., Atlanta, GA 30308-3374. For additional information, contact the office of the Corporate Secretary at (404) 506-7455.

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

Auditors
Deloitte & Touche LLP
Suite 2000
191 Peachtree Street, N.E.
Atlanta, GA 30303

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

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