ALABAMA POWER COMPANY

2009 Annual Report

ALABAMA POWER
A SOUTHERN COMPANY

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Alabama Power Company 2009 Annual Report

The management of Alabama 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, 2009.

This Annual Report does not include an attestation report of the Company's independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by the Company's independent registered public accounting firm pursuant to temporary rules of the Securities and Exchange Commission that permit the Company to provide only management's report in this Annual Report.

Charles D. McCrary
President and Chief Executive Officer

Art P. Beattie
Executive Vice President, Chief Financial Officer, and Treasurer

February 25, 2010

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Alabama Power Company

We have audited the accompanying balance sheets and statements of capitalization of Alabama Power Company (the "Company") (a wholly owned subsidiary of Southern Company) as of December 31, 2009 and 2008, 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, 2009. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such financial statements (pages 26 to 69) present fairly, in all material respects, the financial position of Alabama Power Company at December 31, 2009 and 2008, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Birmingham, Alabama
February 25, 2010

OVERVIEW

Business Activities

Alabama Power Company (the Company) operates as a vertically integrated utility providing electricity to retail and wholesale customers within its traditional service area located in the State of Alabama in addition to wholesale customers in the Southeast. Many factors affect the opportunities, challenges, and risks of the Company's primary business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain energy sales given the effects of the recession, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, fuel, capital expenditures, and restoration following major storms. Appropriately balancing the need to recover these increasing costs with customer prices will continue to challenge the Company for the foreseeable future.

Key Performance Indicators

In striving to maximize shareholder value while providing cost-effective energy to 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 and nuclear 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 fossil/hydro 2009 Peak Season EFOR of 1.50% was better than the target. The nuclear 2009 Peak Season EFOR of 0.14% 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 performance for 2009 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 2009 results compared with its targets for some of these key indicators are reflected in the following chart.

Key Performance Indicator	2009 Target Performance	2009 Actual Performance
Customer Satisfaction	Top quartile in customer surveys	Top quartile
Peak Season EFOR – fossil/hydro	2.75% or less	1.50%
Peak Season EFOR – nuclear	2.75% or less	0.14%
Net Income	$666 million	$670 million

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The performance achieved in 2009 reflects the continued management emphasis, as well as the commitment shown by employees, in achieving or exceeding these key performance expectations.

Earnings

The Company's financial performance remained strong in 2009 despite the challenges of a recessionary economy. The Company's net income after dividends on preferred and preference stock of $670 million in 2009 increased $54 million (8.7%) over the prior year. The increase was primarily due to the corrective rate package providing for adjustments associated with customer charges to certain existing rate structures effective in January 2009, a decrease in other operations and maintenance expenses, and an increase in allowance for funds used during construction (AFUDC) equity. The increase was partially offset by an overall decline in base rate revenues attributable to a decline in kilowatt-hour (KWH) sales, resulting from a recessionary economy and unfavorable weather conditions.

The Company's net income after dividends on preferred and preference stock of $616 million in 2008 increased $36 million (6.3%) over the prior year. This improvement was primarily due to an increase in retail base rate revenues resulting from an increase in rates under the Rate Stabilization and Equalization Plan (Rate RSE) and the Rate Certificated New Plant (Rate CNP) for environmental costs that took effect January 1, 2008, partially offset by higher non-fuel operating expenses and depreciation.

The Company's 2007 net income after dividends on preferred and preference stock was $580 million, representing a $62 million (11.9%) increase from the prior year. This improvement was primarily due to an increase in retail base rate revenues resulting from an increase in rates under Rate RSE and Rate CNP for environmental costs that took effect January 1, 2007 as well as favorable weather conditions, partially offset by higher non-fuel operating expenses and increased interest expense.

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

	Amount	Increase (Decrease) from Prior Year		
	2009	**2009**	2008	2007
		(in millions)		
Operating revenues	**$5,529**	**$(548)**	$717	$345
Fuel	**1,824**	**(360)**	422	90
Purchased power	**307**	**(232)**	99	12
Other operations and maintenance	**1,211**	**(48)**	73	89
Depreciation and amortization	**545**	**25**	49	21
Taxes other than income taxes	**322**	**16**	20	28
Total operating expenses	**4,209**	**(599)**	663	240
Operating income	**1,320**	**51**	54	105
Total other income and (expense)	**(227)**	**19**	2	(11)
Income taxes	**384**	**16**	16	21
Net income	**709**	**54**	40	73
Dividends on preferred and preference stock	**39**	**-**	4	11
Net income after dividends on preferred and preference stock	**$ 670**	**$ 54**	$ 36	$ 62

Operating Revenues

Operating revenues for 2009 were $5.5 billion, reflecting a $548 million decrease from 2008. The following table summarizes the principal factors that have affected operating revenues for the past three years:

	Amount		
	2009	2008	2007
		(in millions)	
Retail – prior year	**$4,862**	$4,407	$3,996
Estimated change in –			
Rates and pricing	**174**	246	216
Sales growth (decline)	**(109)**	26	(5)
Weather	**(12)**	(70)	38
Fuel and other cost recovery	**(418)**	253	162
Retail – current year	**4,497**	4,862	4,407
Wholesale revenues –			
Non-affiliates	**620**	712	627
Affiliates	**237**	309	144
Total wholesale revenues	**857**	1,021	771
Other operating revenues	**175**	194	182
Total operating revenues	**$5,529**	$6,077	$5,360
Percent change	**(9)%**	13%	7%

Retail revenues in 2009 were $4.5 billion. These revenues decreased $365 million (7.5%) in 2009 and increased $455 million (10.3%) and $411 million (10.3%) in 2008 and 2007, respectively. The decrease in 2009 was due to decreased fuel revenue and a decline in KWH sales, partially offset by the corrective rate package providing for adjustments associated with customer charges to certain existing rate structures. The increases in 2008 and 2007 were primarily due to increases in fuel revenue and base rate increases of 5.6% and 5.3%, respectively. See FUTURE EARNINGS POTENTIAL – "PSC Matters" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (decline) and weather.

Fuel rates billed to customers are designed to fully recover fluctuating fuel and purchased power costs over a period of time. Fuel revenues generally have no effect on net income because they represent the recording of revenues to offset fuel and purchased power expenses. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Cost Recovery" for additional information.

Wholesale revenues from sales to non-affiliated utilities were as follows:

	2009	2008	2007
		(in millions)	
Unit power sales –			
Capacity	**$158**	$160	$151
Energy	**207**	238	192
Total	**365**	398	343
Other power sales –			
Capacity and other	**133**	134	128
Energy	**122**	180	156
Total	**255**	314	284
Total non-affiliated	**$620**	$712	$627

Wholesale 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.

Wholesale revenues from sales to non-affiliates include unit power sales under long-term contracts to Florida utilities and sales to wholesale customers within the Company's service territory. Capacity revenues under unit power sales contracts reflect the recovery of fixed costs and a return on investment, and under these contracts, energy is generally sold at variable cost. Fluctuations in the prices of oil and natural gas, which are the primary fuel sources for unit power sales customers, influence changes in these energy sales. However, because energy is generally sold at variable cost, these fluctuations have a minimal effect on earnings. The amounts of long-term unit power sales capacity revenues are scheduled to cease with the termination of the unit power sales contract in May 2010. In June 2010, the capacity subject to the unit power sales contracts will be utilized for retail service. As shown in the table above, unit power sales capacity revenues have ranged from $151 million to $160 million over the last three years. Short-term opportunity energy sales are also included in wholesale energy sales to non-affiliates. These opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost to produce the energy. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Retail Rate Adjustments" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Rate RSE" for additional information.

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 2009, wholesale revenues from sales to affiliates decreased $71.5 million primarily due to a 37.6% decrease in price, partially offset by a 23.2% increase in KWH sales to affiliates as a result of greater availability of the Company's generating resources because of a decrease in customer demand within the Company's service territory. In 2008, wholesale revenues from sales to affiliates increased $164.4 million primarily due to a 62.2% increase in KWH sales to affiliates as a result of greater availability of the Company's generating resources because of a decrease in customer demand within the Company's service territory. In 2007, wholesale revenues from sales to affiliates decreased $71.9 million primarily due to a 37.0% decrease in KWH sales to affiliates as a result of lower availability of the Company's generating resources because of an increase in customer demand within the Company's service territory.

These transactions do not have a significant impact on earnings since the energy is generally sold at marginal cost and energy purchases are generally offset by energy revenues through the Company's energy cost recovery clauses.

Other operating revenues in 2009 decreased $19.6 million (10.1%) from 2008 primarily due to a $42.5 million decrease in revenues from gas-fueled co-generation steam facilities as a result of lower gas prices. This decrease was partially offset by an increase of $10.0 million in customer charges related to late fees. In 2008, other operating revenues increased $12.4 million (6.8%) from 2007 primarily due to an $11.7 million increase in revenues from gas-fueled co-generation steam facilities. In 2007, other operating revenues increased $13.5 million (8.0%) from 2006 primarily due to a $4.0 million increase in revenues from electric property associated with pole attachment and building rentals, a $2.6 million increase in transmission revenues, and a $2.5 million increase in revenues from gas-fueled co-generation steam facilities. Since co-generation steam revenues are generally offset by fuel expense, these revenues did not have a significant impact on earnings for any year reported.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2009 and the percent change by year were as follows:

	KWHs	Percent Change		
	2009	**2009**	2008	2007
	(in billions)			
Residential	**18.1**	**(1.7)%**	(2.6)%	1.3%
Commercial	**14.2**	**(2.5)**	(1.4)	2.8
Industrial	**18.5**	**(15.9)**	(3.2)	(1.6)
Other	**0.2**	**8.1**	0.2	0.7
Total retail	**51.0**	**(7.6)**	(2.5)	0.5
Wholesale -				
Non-affiliates	**14.3**	**(5.8)**	(3.6)	(1.3)
Affiliates	**6.5**	**23.2**	62.2	(37.0)
Total wholesale	**20.8**	**1.6**	7.6	(10.0)
Total energy sales	**71.8**	**(5.1)**	0.0	(2.4)

Changes in retail energy sales are comprised of changes in electricity usage by customers, changes in weather, and changes in the number of customers. Retail energy sales in 2009 were 7.6% less than in 2008. Energy sales were down in 2009 across major classes of customers. Residential and commercial sales decreased 1.7% and 2.5%, respectively, due primarily to unfavorable weather and decreased customer demand in 2009 as compared to 2008. Industrial sales decreased 15.9% during the year as a result of decreased customer demand in all sectors, most significantly in the chemical and primary metals sectors, due to a recessionary economy.

Retail energy sales in 2008 were 2.5% less than in 2007. Energy sales were down in 2008 across major classes of customers. Residential and commercial sales decreased 2.6% and 1.4%, respectively, due primarily to unfavorable weather in 2008 compared to 2007. Industrial sales decreased 3.2% during the year primarily as a result of decreased customer demand in the chemical and pipeline, and textiles and food sectors, as a result of a slowing economy that worsened during the fourth quarter of 2008.

Retail energy sales in 2007 were 0.5% higher than in 2006. Energy sales in the residential and commercial sectors led the growth with a 1.3% and a 2.8% increase, respectively, due primarily to weather-driven increased demand. Industrial sales decreased 1.6% during the year primarily as a result of decreased sales demand in textiles and food, primary metals, and chemical sectors.

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:

	2009	2008	2007
Total generation *(billions of KWHs)*	**68.8**	70.0	69.8
Total purchased power *(billions of KWHs)*	**6.3**	9.2	9.6
Sources of generation *(percent)* –			
Coal	**58**	66	69
Nuclear	**20**	20	19
Gas	**13**	11	10
Hydro	**9**	3	2
Cost of fuel, generated *(cents per net KWH)* –			
Coal	**3.02**	2.94	2.14
Nuclear	**0.56**	0.50	0.50
Gas	**5.24**	8.30	7.43
Average cost of fuel, generated *(cents per net KWH)**	**2.79**	3.00	2.36
Average cost of purchased power *(cents per net KWH)*	**6.05**	7.44	6.07

*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 $2.1 billion in 2009, a decrease of $592.1 million (21.8%) below the prior year costs. This decrease was the result of a $367.3 million decrease related to the volume of KWHs generated and purchased and a $224.8 million decrease in the cost of fuel resulting from lower natural gas prices and an increase in hydro generation.

Fuel and purchased power expenses were $2.7 billion in 2008, an increase of $521.5 million (23.7%) above the prior year costs. This increase was the result of a $560.8 million increase in the cost of fuel, offset by a $39.3 million decrease related to the volume of KWHs generated and purchased.

Fuel and purchased power expenses were $2.2 billion in 2007, an increase of $101.9 million (4.9%) above the prior year costs. This increase was the result of a $70.3 million increase in the cost of fuel and a $31.6 million increase related to the volume of KWHs generated and purchased.

Purchased power consists of purchases from affiliates in the Southern Company system and non-affiliated companies. Purchased power transactions among the Company, its affiliates, and non-affiliates will vary from period to period depending on demand and the availability and variable production cost of generating resources at each company. In 2009, purchased power from non-affiliates decreased $91.1 million (50.9%) due to a 34.9% decrease in the amount of energy purchased and a 24.6% decrease in the average cost per KWH. In 2009, purchased power from affiliates decreased $140.5 million (39.1%) due to a 31.4% decrease in the amount of energy purchased. In 2008, the average cost of purchased power from non-affiliates increased $81.9 million (84.5%) due to a 67.9% increase in the amount of energy purchased. In 2007, purchased power from non-affiliates decreased $27.1 million (21.8%) due to a 22.6% decrease in the amount of energy purchased.

Coal prices continued to be influenced by worldwide demand from developing countries, as well as increased mining and fuel transportation costs. While coal prices reached unprecedented high levels in 2008, the recessionary economy pushed prices downward in 2009. However, the lower prices did not fully offset the higher priced coal already in inventory and under long-term contract. Demand for natural gas in the United States also was affected by the recessionary economy leading to significantly lower natural gas prices. During 2009, uranium prices continued to moderate from the highs set during 2007. Worldwide production levels increased in 2009; however, secondary supplies and inventories were still required to meet worldwide reactor demand.

Fuel and purchased power expenses generally do not affect net income, since they are offset by fuel revenues under the Company's energy cost recovery rate (Rate ECR). The Company, along with the Alabama Public Service Commission (PSC), continuously monitors the under/over recovered balance to determine whether adjustments to billing rates are required. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Cost Recovery" for additional information.

Other Operations and Maintenance Expenses

In 2009, other operations and maintenance expenses decreased $47.6 million (3.8%) primarily due to an $18.1 million decrease in steam production expense related to fewer scheduled outages, a $12.9 million decrease in administrative and general expense related to reductions in employee medical and other benefit-related expenses and in the injuries and damages reserve, a $5.5 million decrease in customer accounts expense, and a $4.7 million decrease in customer service and information expense.

In 2008, other operations and maintenance expenses increased $72.7 million (6.1%) primarily due to a $27.4 million increase in steam production expense related to environmental mandates (which were offset by revenues associated with Rate CNP environmental) and scheduled outage costs, a $22.9 million increase in nuclear production expense related to operations and scheduled outage costs, and a $19.9 million increase in transmission and distribution expense related to overhead line clearing costs.

In 2007, other operations and maintenance expenses increased $89.3 million (8.1%) primarily due to a $28.5 million increase in steam production expense related to environmental mandates and scheduled outage costs, a $19.6 million increase in transmission and distribution expense related to overhead line clearing costs, a $19.0 million increase in administrative and general expenses related to an increase in the expenses for the injuries and damages reserve, outside services, and employee benefits, an $8.1 million increase in nuclear production expense related to scheduled outage cost, and a $4.7 million increase in customer accounts expense associated with customer service expenses.

Depreciation and Amortization

Depreciation and amortization increased $24.5 million (4.7%) in 2009, $48.9 million (10.4%) in 2008, and $20.5 million (4.5%) in 2007, primarily due to additions to property, plant, and equipment related to environmental mandates (which were offset by revenues associated with Rate CNP environmental) and transmission and distribution projects. See Note 3 to financial statements under "Retail Regulatory Matters – Rate CNP" for additional information.

On June 25, 2009, the Company submitted an offer of settlement and stipulation to the FERC relating to the 2008 depreciation study that was filed in October 2008. The settlement offer withdraws the requests for authorization to use updated depreciation rates. In lieu of the new rates, the Company is using those depreciation rates employed prior and up to January 1, 2009 that were previously approved by the FERC. On September 30, 2009, the FERC issued an order approving the settlement offer. See Note 1 to financial statements under "Depreciation and Amortization" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $15.8 million (5.1%) in 2009, $19.9 million (7.0%) in 2008, and $28.4 million (11.0%) in 2007, primarily due to increases in the bases of state and municipal public utility license taxes.

Allowance for Funds Used During Construction Equity

AFUDC equity increased $33.7 million (73.9%) in 2009, $10.1 million (28.5%) in 2008, and $17.2 million (94.1%) in 2007, primarily due to increases in construction work in progress related to environmental mandates at generating facilities, as well as transmission, distribution, and general plant projects compared to the prior years. See Note 1 to financial statements under "Allowance for Funds Used During Construction" for additional information.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized, increased $19.6 million (7.0%) in 2009 primarily due to the issuance of long-term debt, partially offset by additional capitalized interest, as a result of increases in construction work in progress. Interest expense, net of amounts capitalized, increased $5.2 million (1.9%) in 2008 which was not material when compared to the prior year. Interest expense, net of amounts capitalized, increased $21.5 million (8.5%) in 2007 primarily due to higher interest rates on new issuance of long-term debt and higher interest rates on the Company's outstanding variable rate securities.

Income Taxes

Income taxes increased $16.2 million (4.4%) in 2009, primarily due to higher pre-tax income, prior year tax return actualization, and an increase in expense related to normal tax contingencies, partially offset by the tax benefits associated with an increase in AFUDC equity and an increase in the federal production activities deduction.

Income taxes increased $16.6 million (4.7%) in 2008, primarily due to higher pre-tax income partially offset by the tax benefit associated with an increase in AFUDC equity and a decrease in expense related to normal tax contingencies.

Income taxes increased $20.9 million (6.3%) in 2007, primarily due to higher pre-tax income partially offset by the tax benefit associated with an increase in AFUDC equity 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. See Note 3 to financial statements under "Retail Regulatory Matters – Rate RSE" for additional information.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail and wholesale customers within its traditional service area located in the State of Alabama in addition to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Alabama PSC under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings 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 "FERC Matters" and "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 primary business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the 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. Recessionary conditions have negatively impacted sales and are expected to continue to have a negative impact, particularly on industrial and commercial customers. The timing and extent of the economic recovery will 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. Some of the factors driving the potential for such an increase are higher commodity costs, market demand for labor, and scope additions and clarifications. The timing, specific requirements, and estimated costs could also change as environmental statutes and regulations are adopted or modified. See Note 3 to the financial statements under "Environmental Matters" for additional information.

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. These actions were filed concurrently with the issuance of notices of violation of the NSR provisions to each of the traditional operating companies. After the Company was dismissed from the original action, the EPA filed a separate action in January 2001 against the Company in the U.S. District Court for the Northern District of Alabama. In the lawsuit against the Company, the EPA alleges that NSR violations occurred at five coal-fired generating facilities operated by the Company. The civil action requests 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 Georgia Power, 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 the Company and the EPA, resolving a portion of the Company's 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 the Company 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. The decision did not resolve the case, which remains ongoing.

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.

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, on September 21, 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 November 5, 2009, the defendants, including Southern Company, sought rehearing en banc, and the court's ruling is subject to potential appeal. Therefore, 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. On September 30, 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. On November 5, 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. 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 courts have recently determined that private parties and states have standing to bring such claims. For example, on October 16, 2009, the U.S. Court of Appeals for the Fifth Circuit reversed the U.S. District Court for the Southern District of Mississippi's dismissal of private party claims against certain oil, coal, chemical, and utility companies alleging damages as a result of Hurricane Katrina. In reversing the dismissal, the U.S. Court of Appeals for the Fifth Circuit held that plaintiffs have standing to assert their nuisance, trespass, and negligence claims and none of these claims are barred by the political question doctrine. The Company is not currently a party to this litigation but was named as a defendant in an amended complaint which was rendered moot in August 2007 by the U.S. District Court for the Southern District of Mississippi when such court dismissed the original matter. The ultimate outcome of this matter cannot be determined at this time.

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 2009, the Company had invested approximately $2.8 billion in capital projects to comply with these requirements, with annual totals of $526 million, $617 million, and $469 million for 2009, 2008, and 2007, respectively. The Company expects that capital expenditures to assure compliance with existing and new statutes and regulations will be an additional $136 million, $85 million, and $99 million for 2010, 2011, and 2012, respectively. The Company's compliance strategy can be affected by changes to existing environmental laws, statutes, and regulations; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. Environmental costs that are known and estimable at this time are included in capital expenditures discussed under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein.

Compliance with any new federal or state legislation or regulations related to global climate change, air quality, coal combustion byproducts, including coal ash, 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.

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 2009, the Company had spent approximately $2.5 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 being installed at several plants to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

The EPA regulates ground level ozone through implementation of an eight-hour ozone air quality standard. No area within the Company's service area is currently designated as nonattainment under the current standard. In March 2008, however, 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 standard. The EPA is expected to finalize the revised standard in August 2010 and require state implementation plans for any nonattainment areas by December 2013. The revised eight-hour ozone standard is expected to result in designation of new nonattainment areas within the Company's service territory.

During 2005, the EPA's annual fine particulate matter nonattainment designations became effective for several areas within the Company's service area. State plans for addressing the nonattainment designations for this standard could require further reductions in SO_2 and NO_x emissions from power plants. In September 2006, the EPA published a final rule which increased the stringency of the 24-hour average fine particulate matter air quality standard. The Birmingham, Alabama area has been designated as nonattainment for the 24-hour standard, and a state implementation plan for this nonattainment area is due in December 2012.

On December 8, 2009, the EPA also proposed revisions to the National Ambient Air Quality Standard for SO_2. The EPA is expected to finalize the revised SO_2 standard in June 2010.

Twenty-eight eastern states, including the State of 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 State of Alabama has completed its plan to implement CAIR, and emissions reductions are being accomplished by the installation of emissions controls at the Company's coal-fired facilities and/or by the purchase of emissions allowances. The EPA is expected to issue a proposed CAIR replacement rule in July 2010.

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 conditions goal by 2018 and for each ten-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 additional controls beyond CAIR are anticipated to be necessary at any of the Company's facilities. The State of Alabama has completed its implementation plans 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 likely address numerous Hazardous Air Pollutants, including mercury. In March 2005, the EPA issued the Clean Air Mercury Rule (CAMR), a cap and trade program for the reduction of mercury emissions from coal-fired power plants. In February 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated the CAMR. In a separate proceeding in the U.S. District Court for the District of Columbia, the EPA entered into a proposed consent decree that requires the EPA to issue a proposed MACT rule by March 16, 2011 and a final rule by November 16, 2011.

The impacts of the eight-hour ozone standards, the fine particulate matter nonattainment designations, and future revisions to CAIR, the SO_2 standard, the Clean Air Visibility Rule, and MACT rule for the electric generating units on the Company cannot be determined at this time and will depend on the specific provisions of the final rules, resolution of any 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.

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 and plans to install additional controls within the next several years to ensure continued compliance with applicable air quality requirements.

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. On April 1, 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 now in the process of revising the regulations. 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 further rulemaking by the EPA and the actual requirements established by state regulatory agencies and, therefore, cannot be determined at this time.

On December 28, 2009, the EPA announced its determination that revision of the current effluent guidelines for steam electric power plants is warranted and proposed a plan to adopt such revisions by 2013. New wastewater treatment requirements are expected and may result in the installation of additional controls on certain Company 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 EPA is currently evaluating whether additional regulation of coal combustion byproducts is merited under federal solid and hazardous waste laws. The EPA has collected information from the electric utility industry on surface impoundment safety, and conducted on-site inspections at one of the Company's facilities as part of its evaluation. The Company has a routine and robust inspection program in place to ensure the integrity of its coal ash surface impoundments. The EPA is expected to issue a proposal regarding additional regulation of coal combustion byproducts in early 2010. The impact of these additional regulations on the Company will depend on the specific provisions of the final rule and cannot be determined at this time. However, additional regulation of coal combustion byproducts could have a significant impact on the Company's management, beneficial use, and disposal of such byproducts and 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.

Global Climate Issues

Federal legislative proposals that would impose mandatory requirements related to greenhouse gas emissions, renewable energy standards, and energy efficiency standards continue to be considered in Congress, and the reduction of greenhouse gas emissions has been identified as a high priority by the current Administration. On June 26, 2009, the American Clean Energy and Security Act of 2009 (ACES), which would impose mandatory greenhouse gas restrictions through implementation of a cap and trade program, a renewable energy standard, and other measures, was passed by the House of Representatives. ACES would require reductions of greenhouse gas emissions on a national basis to a level that is 17% below 2005 levels by 2020, 42% below 2005 levels by 2030, and 83% below 2005 levels by 2050. In addition, ACES would provide for renewable energy standards of 6% by 2012 and 20% by 2020. Similar legislation is being considered by the Senate. The financial and operational impact of such 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 and natural gas prices, and cost recovery through regulated rates. There can be no assurance that any legislation will be enacted or as to the ultimate form of any legislation. Additional or alternative legislation may be adopted as well.

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. On December 15, 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 September 28, 2009, the EPA published a proposed rule regulating greenhouse gas emissions from new motor vehicles under the Clean Air Act. The EPA has stated that once this rule is effective, it will cause carbon dioxide and other greenhouse gases to become 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. 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. The EPA also published a proposed rule governing how these programs would be applied to stationary sources, including power plants, on October 27, 2009. The EPA has stated that it expects to finalize these proposed rules in March 2010. The ultimate outcome of the endangerment finding and these proposed rules cannot be determined at this time and will depend on additional regulatory action and any legal challenges.

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

Although the outcome of federal, state, or 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. 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 2008, the total carbon dioxide emissions from the fossil fuel-fired electric generating units owned by the Company were approximately 47 million metric tons. The preliminary estimate of carbon dioxide emissions from these units in 2009 is approximately 43 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 continues to evaluate its future energy and emissions profiles and is participating in voluntary programs to reduce greenhouse gas emissions and to help develop and advance technology to reduce emissions.

FERC Matters

In July 2005, the Company filed two applications with the FERC for new 50-year licenses for the Company's seven hydroelectric developments on the Coosa River (Weiss, Henry, Logan Martin, Lay, Mitchell, Jordan, and Bouldin) and for the Lewis Smith and Bankhead developments on the Warrior River. The FERC licenses for all of these nine projects expired in July and August 2007. Since the FERC did not act on the Company's new license applications prior to the expiration of the existing licenses, the FERC is required by law to issue annual licenses to the Company, under the terms and conditions of the existing license, until action is taken on the new license applications. The FERC issued an annual license for the Coosa developments in August 2007 and issued an annual license for the Warrior developments in September 2007. These annual licenses were automatically renewed in 2009 without further action by the FERC to allow the Company to continue operation of the projects under the terms of the previous license while the FERC completes review of the applications for new licenses.

In 2006, the Company initiated the process of developing an application to relicense the Martin hydroelectric project located on the Tallapoosa River. The current Martin license will expire in 2013 and the application for a new license is expected to be filed with the FERC in 2011.

In 2010, the Company will initiate the process of developing an application to relicense the Holt hydroelectric project located on the Warrior River. The current Holt license will expire on August 31, 2015, and the application for a new license is expected to be filed prior to that time.

Upon or after the expiration of each license, the U.S. Government, by act of Congress, may take over the project or the FERC may relicense the project either to the original licensee or to a new licensee. The FERC may grant relicenses subject to certain requirements that could result in additional costs to the Company. The timing and final outcome of the Company's relicense applications cannot now be determined.

PSC Matters

Retail Rate Adjustments

Rate RSE

Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate adjustments for any two-year period, when averaged together, cannot exceed 4.0% per year and any annual adjustment is limited to 5.0%. Retail rates remain unchanged when the retail return on common equity is projected to be between 13.0% and 14.5%. If the Company's actual retail return on common equity is above the allowed equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail return on common equity fall below the allowed equity return range.

In October 2008, the Alabama PSC approved a corrective rate package, effective January 2009, that primarily provides for adjustments associated with customer charges to certain existing rate structures. The Company agreed to a moratorium on any increase in rates in 2009 under the Rate RSE.

On December 1, 2009, the Company made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2010. The Rate RSE increase for 2010 is 3.24%, or $152 million annually, and was effective in January 2010. The revenue adjustment under the Rate RSE is largely attributable to the costs associated with fossil capacity which is currently dedicated to certain long-term wholesale contracts that expire during 2010. Retail cost of service for 2010 reflects the cost for that portion of the year in which this capacity is no longer committed to wholesale. The termination of these long-term wholesale contracts will result in a significant decrease in unit power sales capacity revenues. In an Alabama PSC order dated January 5, 2010, the Alabama PSC acknowledged that a full calendar year of costs for such capacity would be reflected in the Rate RSE calculation beginning in 2011 and thereafter. Under the terms of Rate RSE, the maximum increase for 2011 cannot exceed 4.76%.

Rate CNP

The Company's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service and the recovery of retail costs associated with certificated power purchase agreements (PPAs) under a Rate CNP. There was no adjustment to the Rate CNP to recover certificated PPA costs in 2007, 2008, or 2009. Effective April 2010, Rate CNP will be reduced approximately $70 million annually, primarily due to the expiration on May 31, 2010 of the PPA with Southern Power covering the capacity of Plant Harris Unit 1.

Rate CNP also allows for the recovery of the Company's retail costs associated with environmental laws, regulations, or other such mandates. The rate mechanism is based on forward looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on invested capital. Retail rates increased approximately 0.6% in January 2007 and 2.4% in January 2008 due to environmental costs. In October 2008, the Company agreed to defer collection of any increase in rates under this portion of Rate CNP, which permits recovery of costs associated with environmental laws and regulations, from 2009 until 2010. The deferral of the retail rate adjustments had an immaterial impact on annual cash flows, and had no significant effect on the Company's revenues or net income. On December 1, 2009, the Company made its Rate CNP environmental submission of projected data for calendar year 2010, resulting in an increase to retail rates of approximately 4.3%, or an additional $195 million annually, based upon projected billings. Under the terms of the rate mechanism, this adjustment became effective in January 2010. The Rate CNP environmental adjustment is primarily attributable to scrubbers being placed in service during 2010 at four of the Company's generating units. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate CNP" for further information.

Fuel Cost Recovery

The Company has established fuel cost recovery rates under Rate ECR approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. The Company, along with the Alabama PSC, will continue to monitor the over recovered fuel cost balance to determine whether an additional adjustment to billing rates is required.

In June 2007, the Alabama PSC ordered the Company to increase its Rate ECR factor to 3.100 cents per KWH effective with billings beginning July 2007. In October 2008, the Alabama PSC approved an increase in the Company's Rate ECR factor to 3.983 cents per KWH effective with billings beginning October 2008.

On June 2, 2009, the Alabama PSC approved a decrease in the Company's Rate ECR factor to 3.733 cents per KWH for billings beginning June 9, 2009. On December 1, 2009, the Alabama PSC approved a decrease in the Company's Rate ECR factor to 2.731 cents per KWH for billings beginning January 2010 through December 2011. The Alabama PSC further approved an additional reduction in the Rate ECR factor of 0.328 cents per KWH for the billing months of January 2010 through December 2010 resulting in a Rate ECR factor of 2.403 cents per KWH for such 12-month period. For billing months beginning January 2012, the Rate ECR factor shall be 5.910 cents per KWH, absent a contrary order by the Alabama PSC. Rate ECR revenues, as recorded on the financial statements, are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, the approved decreases in the Rate ECR factor will have no significant effect on the Company's net income, but will decrease operating cash flows related to fuel cost recovery in 2010 when compared to 2009.

As of December 31, 2009, the Company had an over recovered fuel balance of approximately $199.6 million, of which approximately $22.1 million is included in deferred over recovered regulatory clause revenues in the balance sheets. As of December 31, 2008, the

Company had an under recovered fuel balance of approximately $305.8 million, of which approximately $180.9 million is included in deferred under recovered regulatory clause revenues in the balance sheets. These classifications are based on estimates, which include such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any return of the over recovered fuel costs or recovery of under recovered fuel costs. See Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Cost Recovery" for further information.

Natural Disaster Reserve

Based on an order from the Alabama PSC, the Company maintains a reserve for operations and maintenance expense to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly natural disaster reserve (NDR) charge to customers consisting of two components. The first component is intended to establish and maintain a target reserve balance of $75 million for future storms and is an on-going part of customer billing. The second component of the NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 24-month period. The Alabama PSC order gives the Company authority to record a deficit balance in the NDR when costs of storm damage exceed any established reserve balance. Absent further Alabama PSC approval, the maximum total NDR charge consisting of both components is $10 per month per non-residential customer account and $5 per month per residential customer account. The Company has discretionary authority to accrue certain additional amounts as circumstances warrant.

In addition to the monthly NDR charge, the Company accrued $39.6 million of discretionary reserve in 2009 resulting in an accumulated balance of approximately $75 million in the reserve for future storms as of December 31, 2009. This reserve is included in other regulatory liabilities, deferred in the balance sheets. Effective February 2010, billings will be reduced to $0.37 per month per non-residential customer account and $0.15 per month per residential customer account, consistent with the Alabama PSC order to maintain the target NDR balance. The Company has fully recovered its deferred storm costs; therefore, rates do not include the second component of the NDR charge.

As revenue from the NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, any change in revenue and expense will not have an effect on net income but will decrease operating cash flows related to the NDR charge in 2010 when compared to 2009.

The net effect of the changes in 2010 in the Rate ECR factor, Rate RSE, Rate CNP, and NDR will result in an overall annual reduction in the Company's retail customers' billings of approximately $433 million.

Steam Service

On February 5, 2009, the Alabama PSC granted a Certificate of Abandonment of Steam Service in the downtown area of the City of Birmingham. The order allows the Company to discontinue steam service by the earlier of three years from May 14, 2008 or when it has no remaining steam service customers. Currently, the Company has contractual obligations to provide steam service until 2013. Impacts related to the abandonment of steam service are recognized in operating income and are not material to the earnings of the Company.

Legislation

On February 17, 2009, President Obama signed into law the American Recovery and Reinvestment Act of 2009 (ARRA). Major tax incentives in the ARRA include an extension of bonus depreciation and multiple renewable energy incentives, which could have a significant impact on the future cash flow and net income of the Company. The Company's cash flow reduction to 2009 tax payments as a result of the bonus depreciation provisions of the ARRA was approximately $104 million. On December 8, 2009, President Obama announced proposals to accelerate job growth that include an extension of the bonus depreciation provision for the ARRA for 2010, which could have a significant impact on the future cash flow and net income of the Company.

On October 27, 2009, Southern Company and its subsidiaries received notice that an award of $165 million had been granted, of which $65 million is available to the Company, under the ARRA grant application for transmission and distribution automation and modernization projects pending final negotiations. The Company continues to assess the other financial implications of the ARRA.

The U.S. House of Representatives and the U.S. Senate have passed separate bills related to healthcare reform. Both bills include a provision that would make Medicare Part D subsidy reimbursements taxable. If enacted into law, this provision could have a significant negative impact on the Company's net income. See Note 2 to the financial statements under "Other Postretirement Benefits" for additional information.

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

Income Tax Matters

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 is phased in over the years 2005 through 2010 with a 3% rate applicable to the years 2005 and 2006, a 6% rate applicable for the years 2007 through 2009, and a 9% rate thereafter. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Other Matters

In accordance with accounting standards related to employers' accounting for pensions, the Company recorded non-cash pre-tax pension income of approximately $24 million, $26 million, and $17 million in 2009, 2008, and 2007, respectively. Postretirement benefit costs for the Company were $19 million, $23 million, and $27 million in 2009, 2008, and 2007, respectively. Such amounts are dependent on several factors including trust earnings and changes to the plans. A portion of pension and postretirement benefit costs is capitalized based on construction-related labor charges. Pension and postretirement benefit costs are a component of the regulated rates and generally do not have a long-term effect on net income. For more information regarding pension and postretirement benefits, see Note 2 to the financial statements.

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. 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 United States. 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 accounting principles generally accepted in the United States. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed critical accounting policies and estimates described below with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

The Company is subject to retail regulation by the Alabama PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies 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 financial statements than they would on a non-regulated company.

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

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 generally accepted accounting principles (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 Internal Revenue Service (IRS) or Alabama Department of Revenue interpretations of existing regulations.
- Identification of sites that require environmental remediation or the filing of other complaints in which the Company may be asserted to be a potentially responsible party.
- Identification and evaluation of other potential lawsuits or complaints in which the Company may be named as a defendant.
- Resolution or progression of new or existing matters through the legislative process, the court systems, the IRS, the Alabama Department of Revenue, 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 considers 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 $6 million or less change in total benefit expense and a $68 million or less change in projected obligations.

New Accounting Standards

Variable Interest Entities

In June 2009, the Financial Accounting Standards Board issued new guidance on the consolidation of variable interest entities, which replaces the quantitative-based risks and rewards calculation for determining whether an enterprise is the primary beneficiary in a variable interest entity with an approach that is primarily qualitative, requires ongoing assessments of whether an enterprise is the primary beneficiary of a variable interest entity, and requires additional disclosures about an enterprise's involvement in variable interest entities. The Company adopted this new guidance effective January 1, 2010, with no material impact on its financial statements.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2009. Throughout the turmoil in the financial markets, the Company has maintained adequate access to capital without drawing on any of its committed bank credit arrangements used to support its commercial paper programs and variable rate pollution control revenue bonds. 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. Market rates for committed credit have increased, and the Company has been and expects to continue to be subject to higher costs as its existing facilities are replaced or renewed. Total committed credit fees for the Company average less than ¼ of 1% per year. See "Sources of Capital" and "Financing Activities" herein for additional information.

The Company's investments in pension and nuclear decommissioning trust funds remained stable in value as of December 31, 2009. The Company expects that the earliest that cash may have to be contributed to the pension trust fund is 2012. The projections of the amount vary significantly depending on key variables, including future trust fund performance, and cannot be determined at this time. The Company's funding obligations for the nuclear decommissioning trust are based on the site study, and the next study is expected to be conducted in 2013.

Net cash provided from operating activities in 2009 totaled $1.6 billion, an increase of $424 million as compared to 2008. The increase was primarily due to an increase in net income, as previously discussed, a decrease in receivables, and an increase in other current liabilities attributable to collections on regulatory clauses. Net cash provided from operating activities in 2008 totaled $1.2 billion, an increase of $30 million as compared to 2007. The increase included additional use of funds for fossil fuel inventory and payment of operating expenses along with a higher receivables balance as compared to 2007. This use of funds was offset by an increase in cash from net income as previously discussed and higher depreciation expense along with a decrease in the payments for federal taxes as compared to 2007. Net cash provided from operating activities in 2007 totaled $1.2 billion, an increase of $194 million as compared to 2006. The increase was primarily due to an increase in net income resulting from price increases, an increase in deferred taxes, and the timing of payments related to operating expenses.

Net cash used for investing activities totaled $1.2 billion, $1.6 billion, and $1.3 billion for 2009, 2008, and 2007, respectively, primarily due to gross property additions to utility plant of $1.2 billion, $1.5 billion and $1.2 billion for 2009, 2008, and 2007, respectively. These additions were primarily related to environmental mandates, construction of transmission and distribution facilities, replacement of steam generation equipment, and purchases of nuclear fuel.

Net cash used for financing activities totaled $35 million in 2009 primarily due to redemptions of debt securities and dividends paid in excess of debt issuances and cash raised from common stock sales. In 2008 and 2007, net cash provided from financing activities totaled $375 million and $162 million, respectively, primarily due to long-term debt issuances and cash raised from common stock sales in excess of redemptions of securities and dividends paid. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and securities redeemed.

Significant balance sheet changes for 2009 include increases of $340 million in cash primarily from collections on regulatory clauses. These cash collections correspondingly decreased current and deferred under recovered regulatory clause revenues by $297 million and increased current and deferred over recovered regulatory clause revenues by $204 million. Other changes include increases of $939 million in gross plant related to environmental mandates and transmission and distribution projects and $478 million in long-term debt. In 2008, significant balance sheet changes included an increase of $966 million in gross plant and an increase of $855 million in long-term debt, primarily due to an increase in environmental-related equipment. Other significant balance sheet changes in 2008 were a result of a decline in the market value of the Company's pension trust and nuclear decommissioning trust funds, impacting the Company's other regulatory assets and liabilities. In 2007, significant balance sheet changes included an increase of $671 million in gross plant and an increase of $602 million in long-term debt, primarily due to an increase in environmental-related equipment.

The Company's ratio of common equity to total capitalization, including short-term debt, was 43.3% in 2009, 42.5% in 2008, and 42.5% in 2007. See Note 6 to the financial statements for additional information.

The Company has maintained investment grade credit ratings from the major rating agencies with respect to debt, preferred securities, preferred stock, and preference stock. See SELECTED FINANCIAL AND OPERATING DATA for additional information regarding the Company's securities ratings.

Sources of Capital

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

Security issuances are subject to regulatory approval by the Alabama PSC. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission under the Securities Act of 1933, as amended. The amounts of securities authorized by the Alabama PSC 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 sometimes exceed current assets because of the Company's debt due within one year and the periodic use of short-term debt as a funding source primarily to meet scheduled maturities of long-term debt, as well as cash needs which can fluctuate significantly due to the seasonality of the business.

To meet short-term cash needs and contingencies, the Company has various internal and external sources of liquidity. At December 31, 2009, the Company had approximately $368 million of cash and cash equivalents and $1.3 billion of unused credit arrangements with banks, as described below. In addition, the Company has substantial cash flow from operating activities and access to the capital markets, including a commercial paper program, to meet liquidity needs.

The Company maintains committed lines of credit in the amount of $1.3 billion, of which $481 million will expire at various times during 2010. $372 million of the credit facilities expiring in 2010 allow for the execution of term loans for an additional one-year period. $765 million of credit facilities expire in 2012. A portion of the unused credit with banks is allocated to provide liquidity support to the Company's variable rate pollution control revenue bonds. The amount of variable rate pollution control revenue bonds requiring liquidity support as of December 31, 2009 was approximately $608 million. Subsequent to December 31, 2009, two remarketings of pollution control revenue bonds increased that amount to $744 million. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper 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 such issuances for the benefit of any other traditional operating company. The obligations of each company under these arrangements are several and there is no cross-affiliate credit support.

The Company had no commercial paper outstanding as of December 31, 2009, and $25 million outstanding as of December 31, 2008.

Financing Activities

In March 2009, the Company issued $500 million of Series 2009A 6.00% Senior Notes due March 1, 2039. The proceeds were used to repay short-term indebtedness and for other general corporate purposes, including the Company's continuous construction program.

In June 2009, the Company incurred obligations related to the issuance of $53 million of the Industrial Development Board of the City of Mobile, Alabama Pollution Control Revenue Bonds (Alabama Power Barry Plant Project), First Series 2009. The proceeds were used to fund pollution control and environmental improvement facilities at Plant Barry.

In July 2009, the Company issued 3,375,000 shares of common stock to Southern Company at $40 a share ($135 million aggregate purchase price). The proceeds were used for general corporate purposes.

In August 2009, the Company's $250 million Series BB Floating Rate Senior Notes due August 25, 2009 matured.

In October 2009, the Company issued 1,687,500 shares of common stock to Southern Company at $40 a share ($67.5 million aggregate purchase price). The proceeds were used for general corporate purposes.

In December 2009, the Company incurred obligations related to the issuance of $25.5 million of the Industrial Development Board of the City of Mobile, Alabama Solid Waste Disposal Revenue Bonds (Alabama Power Barry Plant Project), Second Series 2009. The proceeds were used to fund certain solid waste disposal facilities at Plant Barry.

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 primarily for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, emissions allowances, and energy price risk management. At December 31, 2009, the maximum potential collateral requirements under these contracts at a BBB- and/or Baa3 rating were approximately $5 million. At December 31, 2009, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $324 million. 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.

Market Price Risk

Due to cost-based rate regulations, the Company has limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures, 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. Company policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company enters into forward starting interest rate swaps and other derivatives that have been designated as hedges. The weighted average interest rate on $232 million of long-term variable interest rate exposure that has not been hedged at January 1, 2010 was 3.0%. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $2.3 million at January 1, 2010. 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 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 has implemented fuel hedging programs per the guidelines of the Alabama PSC.

In addition, the Company's Rate ECR allows the recovery of specific costs associated with the sales of natural gas that become necessary due to operating considerations at the Company's electric generating facilities. Rate ECR also allows recovery of the cost of financial instruments used for hedging market price risk up to 75% of the budgeted annual amount of natural gas purchases. The Company may not engage in natural gas hedging activities that extend beyond a rolling 42-month window. Also, the premiums paid for natural gas financial options may not exceed 5% of the Company's natural gas budget for that year.

The changes in fair value of energy-related derivative contracts were as follows at December 31:

	2009 Changes	2008 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$(92)**	$ -
Contracts realized or settled	**123**	(44)
Current period changes[(a)]	**(75)**	(48)
Contracts outstanding at the end of the period, assets (liabilities), net	**$(44)**	$(92)

(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, 2009 was an increase of $47.6 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 prices of natural gas. At December 31, 2009, the Company had a net hedge volume of 37.3 million mmBtu with a weighted average contract cost approximately $1.20 per mmBtu above market prices, and 44.5 million mmBtu at December 31, 2008 with a weighted average contract cost approximately $2.12 per mmBtu above market prices. The majority of the natural gas hedges are recovered through the fuel cost recovery clause.

At December 31, the net fair value of energy-related derivative contracts by hedge designation was reflected in the financial statements as assets/(liabilities) as follows:

Asset (Liability) Derivatives	**2009**	2008
	(in millions)	
Regulatory hedges	**$(44)**	$(92)
Cash flow hedges	-	-
Not designated	-	-
Total fair value	**$(44)**	$(92)

Energy-related derivative contracts which are designated as regulatory hedges relate to the Company's fuel hedging program where 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 clause. Certain other gains and losses on energy-related derivatives, designated as cash flow hedges, are initially deferred in other comprehensive income before being recognized in income in the same period as the hedged transaction. 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.

Unrealized pre-tax gains and losses from energy-related derivative contracts recognized in income were not material for any year presented.

The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at December 31, 2009 are as follows:

	December 31, 2009 Fair Value Measurements			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
	(in millions)			
Level 1	$ -	$ -	$ -	$ -
Level 2	(44)	(34)	(10)	-
Level 3	-	-	-	-
Fair value of contracts outstanding at end of period	$(44)	$(34)	$(10)	$ -

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 on fair value measurement.

The Company is exposed to market price risk in the event of nonperformance by counterparties to 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 S&P 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.

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to be $1.0 billion for 2010, $1.0 billion for 2011, and $1.1 billion for 2012. Environmental expenditures included in these estimated amounts are $136 million, $85 million, and $99 million for 2010, 2011, and 2012, respectively. Also included over the next three years, the Company estimates spending $653 million on Plant Farley (including nuclear fuel), $882 million on distribution facilities, and $481 million on transmission additions. See Note 7 to the financial statements under "Construction Program" for additional details.

The construction programs are 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; revised load growth estimates; changes in environmental statutes and regulations; changes in nuclear plants to meet new regulatory requirements; changes in FERC rules and regulations; Alabama PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. As a result of Nuclear Regulatory Commission requirements, the Company has external trust funds for nuclear decommissioning costs; however, the Company currently has no additional funding requirements. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning."

In addition to the funds required for the Company's construction program, approximately $800 million will be required by the end of 2012 for maturities of long-term debt. The Company plans to continue, when economically feasible, to retire higher cost securities and replace these obligations with lower cost capital if market conditions permit.

The Company has also established an external trust fund for postretirement benefits as ordered by the Alabama PSC. The cumulative effect of funding these items over an extended period will diminish internally funded capital for other purposes and may require the Company to seek capital from other sources. See Note 2 to the financial statements for additional information.

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 as follows. See Notes 1, 6, 7, and 11 to the financial statements for additional information.

Contractual Obligations

	2010	2011-2012	2013-2014	After 2014	Uncertain Timing [(d)]	Total
			(in millions)			
Long-term debt[(a)] –						
Principal	$ 100	$ 700	$ 250	$ 5,136	$ -	$ 6,186
Interest	311	603	530	4,846	-	6,290
Preferred and preference stock dividends[(b)]	39	79	79	-	-	197
Energy-related derivative obligations[(c)]	34	11	-	-	-	45
Operating leases	22	21	8	10	-	61
Unrecognized tax benefits and interest[(d)]	-	-	-	-	6	6
Purchase commitments[(e)] –						
Capital [(f)]	912	1,919	-	-	-	2,831
Limestone[(g)]	11	30	32	54	-	127
Coal	1,420	1,589	923	975	-	4,907
Nuclear fuel	73	99	60	90	-	322
Natural gas [(h)]	413	451	254	148	-	1,266
Purchased power	39	60	67	337	-	503
Long-term service agreements[(i)]	23	48	50	135	-	256
Postretirement benefits trust[(j)]	11	22	-	-	-	33
Total	$3,408	$5,632	$2,253	$11,731	$6	$23,030

(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, 2010, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk.

(b) Preferred and preference stock do not mature; therefore, amounts are provided 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 $6 million in unrecognized tax benefits and 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. See Note 5 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 2009, 2008, and 2007 were $1.21 billion, $1.26 billion, and $1.19 billion, respectively.

(f) The Company forecasts capital expenditures over a three-year period. Amounts represent current estimates of total expenditures excluding those amounts related to contractual purchase commitments for nuclear fuel. At December 31, 2009, significant purchase commitments were outstanding in connection with the construction program.

(g) As part of the Company's program to reduce sulfur dioxide emissions from certain of 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, 2009.

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

(j) The Company forecasts postretirement trust contributions over a three-year period. The Company expects that the earliest that cash may have to be contributed to the pension trust fund is 2012. The projections of the amount vary significantly depending on key variables including future trust fund performance and cannot be determined at this time. Therefore, no amounts related to the pension trust are included in the table. See Note 2 to the financial statements for additional information related to the pension and postretirement plans, including estimated benefit payments. Certain benefit payments will be made through the related trusts. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2009 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales and retail rates, storm damage cost recovery and repairs, fuel cost recovery and other rate actions, environmental regulations and expenditures, access to sources of capital, projections for postretirement benefit and nuclear decommissioning trust contributions, financing activities, start and completion of construction projects, filings with state and federal regulatory authorities, impacts of adoption of new accounting rules, impact of the American Recovery and Reinvestment Act of 2009, impact of healthcare legislation, if any, estimated sales and purchases under new power sale and purchase agreements, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory change, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, implementation of the Energy Policy Act of 2005, environmental laws including regulation of water quality and emissions of sulfur, nitrogen, mercury, carbon, soot, particulate matter, or coal combustion byproducts and other substances, 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 and 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 trusts;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- 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.

STATEMENTS OF INCOME

For the Years Ended December 31, 2009, 2008, and 2007

Alabama Power Company 2009 Annual Report

	2009	2008	2007
		(in thousands)	
Operating Revenues:			
Retail revenues	**$4,497,081**	$4,862,281	$4,406,956
Wholesale revenues, non-affiliates	**619,859**	711,903	627,047
Wholesale revenues, affiliates	**236,995**	308,482	144,089
Other revenues	**174,639**	194,265	181,901
Total operating revenues	**5,528,574**	6,076,931	5,359,993
Operating Expenses:			
Fuel	**1,823,784**	2,184,310	1,762,418
Purchased power, non-affiliates	**87,737**	178,807	96,928
Purchased power, affiliates	**218,654**	359,202	341,461
Other operations and maintenance	**1,211,245**	1,258,888	1,186,235
Depreciation and amortization	**544,923**	520,449	471,536
Taxes other than income taxes	**322,274**	306,522	286,579
Total operating expenses	**4,208,617**	4,808,178	4,145,157
Operating Income	**1,319,957**	1,268,753	1,214,836
Other Income and (Expense):			
Allowance for equity funds used during construction	**79,175**	45,519	35,425
Interest income	**16,906**	19,394	19,545
Interest expense, net of amounts capitalized	**(298,495)**	(278,917)	(273,737)
Other income (expense), net	**(24,564)**	(31,514)	(29,144)
Total other income and (expense)	**(226,978)**	(245,518)	(247,911)
Earnings Before Income Taxes	**1,092,979**	1,023,235	966,925
Income taxes	**383,980**	367,813	351,198
Net Income	**708,999**	655,422	615,727
Dividends on Preferred and Preference Stock	**39,463**	39,463	36,145
Net Income After Dividends on Preferred and Preference Stock	**$ 669,536**	$ 615,959	$ 579,582

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

STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2009, 2008, and 2007

Alabama Power Company 2009 Annual Report

	2009	2008	2007
		(in thousands)	
Operating Activities:			
Net income	**$ 708,999**	$ 655,422	$ 615,727
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization, total	**636,788**	599,767	548,959
Deferred income taxes	**(65,907)**	126,538	21,269
Allowance for equity funds used during construction	**(79,175)**	(45,519)	(35,425)
Pension, postretirement, and other employee benefits	**(25,802)**	(26,530)	(18,781)
Stock based compensation expense	**3,767**	3,105	4,900
Tax benefit of stock options	**166**	685	1,118
Other, net	**62,318**	27,687	(13,648)
Changes in certain current assets and liabilities --			
-Receivables	**310,203**	(31,692)	(5,798)
-Fossil fuel stock	**(76,602)**	(134,212)	(33,840)
-Materials and supplies	**(21,989)**	(17,723)	(32,543)
-Other current assets	**(16,253)**	(1,493)	22,353
-Accounts payable	**(18,767)**	(8,751)	78,508
-Accrued taxes	**24,415**	36,957	(17,248)
-Accrued compensation	**(31,684)**	(4,722)	4,194
-Other current liabilities	**192,835**	(198)	10,098
Net cash provided from operating activities	**1,603,312**	1,179,321	1,149,843
Investing Activities:			
Property additions	**(1,233,580)**	(1,477,644)	(1,157,186)
Investment in restricted cash from pollution control bonds	**(5,673)**	(96,326)	(97,775)
Distribution of restricted cash from pollution control bonds	**49,041**	35,979	78,043
Nuclear decommissioning trust fund purchases	**(244,662)**	(300,503)	(334,275)
Nuclear decommissioning trust fund sales	**243,796**	299,636	333,409
Cost of removal net of salvage	**(37,883)**	(41,744)	(48,932)
Other investing activities	**165**	(19,142)	(26,621)
Net cash used for investing activities	**(1,228,796)**	(1,599,744)	(1,253,337)
Financing Activities:			
Increase (decrease) in notes payable, net	**(24,995)**	24,995	(119,670)
Proceeds --			
Common stock issued to parent	**202,500**	300,000	229,000
Capital contributions from parent company	**23,949**	21,272	27,867
Gross excess tax benefit of stock options	**485**	1,289	2,556
Preference stock	**-**	-	200,000
Pollution control revenue bonds	**78,500**	265,100	265,500
Senior notes issuances	**500,000**	850,000	850,000
Redemptions --			
Preferred stock	**-**	(125,000)	-
Pollution control revenue bonds	**-**	(11,100)	-
Senior notes	**(250,000)**	(410,000)	(668,500)
Other long-term debt	**-**	-	(103,093)
Payment of preferred and preference stock dividends	**(39,470)**	(40,899)	(31,380)
Payment of common stock dividends	**(522,800)**	(491,300)	(465,000)
Other financing activities	**(2,850)**	(9,369)	(25,709)
Net cash provided from (used for) financing activities	**(34,681)**	374,988	161,571
Net Change in Cash and Cash Equivalents	**339,835**	(45,435)	58,077
Cash and Cash Equivalents at Beginning of Year	**28,181**	73,616	15,539
Cash and Cash Equivalents at End of Year	**$ 368,016**	$ 28,181	$ 73,616
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $33,112, $20,215 and $17,961 capitalized, respectively)	**254,989**	258,918	248,289
Income taxes (net of refunds)	**426,390**	214,368	340,951

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

BALANCE SHEETS
At December 31, 2009 and 2008
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Assets	2009	2008
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 368,016**	$ 28,181
Restricted cash	**36,711**	80,079
Receivables --		
Customer accounts receivable	**322,292**	350,410
Unbilled revenues	**134,875**	98,921
Under recovered regulatory clause revenues	**37,338**	153,899
Other accounts and notes receivable	**33,522**	44,645
Affiliated companies	**61,508**	70,612
Accumulated provision for uncollectible accounts	**(9,551)**	(8,882)
Fossil fuel stock, at average cost	**394,511**	322,089
Materials and supplies, at average cost	**326,074**	305,880
Vacation pay	**53,607**	52,577
Prepaid expenses	**111,320**	88,219
Other regulatory assets, current	**34,347**	74,825
Other current assets	**6,203**	12,915
Total current assets	**1,910,773**	1,674,370
Property, Plant, and Equipment:		
In service	**18,574,229**	17,635,129
Less accumulated provision for depreciation	**6,558,864**	6,259,720
Plant in service, net of depreciation	**12,015,365**	11,375,409
Nuclear fuel, at amortized cost	**253,308**	231,862
Construction work in progress	**1,256,311**	1,092,516
Total property, plant, and equipment	**13,524,984**	12,699,787
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**59,628**	50,912
Nuclear decommissioning trusts, at fair value	**489,795**	403,966
Miscellaneous property and investments	**69,749**	62,782
Total other property and investments	**619,172**	517,660
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**387,447**	362,596
Prepaid pension costs	**132,643**	166,334
Deferred under recovered regulatory clause revenues	**-**	180,874
Other regulatory assets, deferred	**750,492**	732,367
Other deferred charges and assets	**198,582**	202,018
Total deferred charges and other assets	**1,469,164**	1,644,189
Total Assets	**$17,524,093**	$16,536,006

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

BALANCE SHEETS
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Liabilities and Stockholder's Equity	**2009**	2008
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$ 100,000**	$ 250,079
Notes payable	**-**	24,995
Accounts payable --		
Affiliated	**194,675**	178,708
Other	**328,400**	358,176
Customer deposits	**86,975**	77,205
Accrued taxes --		
Accrued income taxes	**14,789**	18,299
Other accrued taxes	**31,918**	30,372
Accrued interest	**65,455**	56,375
Accrued vacation pay	**44,751**	44,217
Accrued compensation	**71,286**	91,856
Liabilities from risk management activities	**37,844**	83,873
Over recovered regulatory clause revenues	**181,565**	-
Other current liabilities	**40,020**	53,777
Total current liabilities	**1,197,678**	1,267,932
Long-Term Debt (See accompanying statements)	**6,082,489**	5,604,791
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**2,293,468**	2,243,117
Deferred credits related to income taxes	**88,705**	90,083
Accumulated deferred investment tax credits	**164,713**	172,638
Employee benefit obligations	**387,936**	396,923
Asset retirement obligations	**491,007**	461,284
Other cost of removal obligations	**668,151**	634,792
Other regulatory liabilities, deferred	**169,224**	79,151
Deferred over recovered regulatory clause revenues	**22,060**	-
Other deferred credits and liabilities	**37,113**	45,858
Total deferred credits and other liabilities	**4,322,377**	4,123,846
Total Liabilities	**11,602,544**	10,996,569
Redeemable Preferred Stock (See accompanying statements)	**341,715**	341,715
Preference Stock (See accompanying statements)	**343,373**	343,412
Common Stockholder's Equity (See accompanying statements)	**5,236,461**	4,854,310
Total Liabilities and Stockholder's Equity	**17,524,093**	$16,536,006
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION

At December 31, 2009 and 2008

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	2009	2008	**2009**	2008
	(in thousands)		*(percent of total)*	
Long-Term Debt:				
Long-term debt payable to affiliated trusts --				
Variable rate (3.35% at 1/1/10) due 2042	**$ 206,186**	$ 206,186		
Long-term notes payable --				
Floating rate (2.34% at 1/1/09) due 2009	**-**	250,000		
4.70% due 2010	**100,000**	100,000		
5.10% due 2011	**200,000**	200,000		
4.85% due 2012	**500,000**	500,000		
5.80% due 2013	**250,000**	250,000		
5.125% to 6.375% due 2016-2047	**3,775,000**	3,275,000		
Total long-term notes payable	**4,825,000**	$4,575,000		
Other long-term debt --				
Pollution control revenue bonds --				
1.40% to 5.00% due 2030-2038	**553,500**	500,500		
Variable rates (0.18% to 0.44% at 1/1/10) due 2015-2036	**601,690**	576,190		
Total other long-term debt	**1,155,190**	1,076,690		
Capitalized lease obligations	**-**	79		
Unamortized debt premium (discount), net	**(3,887)**	(3,085)		
Total long-term debt (annual interest requirement -- $311.4 million)	**6,182,489**	5,854,870		
Less amount due within one year	**100,000**	250,079		
Long-term debt excluding amount due within one year	**6,082,489**	5,604,791	**50.7%**	50.3%

STATEMENTS OF CAPITALIZATION (continued)
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	2009	2008	**2009**	2008
		(in thousands)		*(percent of total)*
Preferred and Preference Stock:				
Cumulative redeemable preferred stock				
$100 par or stated value -- 4.20% to 4.92%				
Authorized - 3,850,000 shares				
Outstanding - 475,115 shares	**47,610**	47,610		
$1 par value -- 5.20% to 5.83%				
Authorized - 27,500,000 shares				
Outstanding - 12,000,000 shares: $25 stated value	**294,105**	294,105		
Preference stock				
Authorized - 40,000,000 shares				
Outstanding - $1 par value -- 5.63% to 6.50%				
- 14,000,000 shares				
(non-cumulative) $25 stated value	**343,373**	343,412		
Total preferred and preference stock				
(annual dividend requirement -- $39.5 million)	**685,088**	685,127	**5.7**	6.1
Common Stockholder's Equity:				
Common stock, par value $40 per share --				
Authorized - 2009: 40,000,000 shares				
- 2008: 40,000,000 shares				
Outstanding - 2009: 30,537,500 shares	**1,221,500**	1,019,000		
- 2008: 25,475,000 shares				
Paid-in capital	**2,119,818**	2,091,462		
Retained earnings	**1,900,526**	1,753,797		
Accumulated other comprehensive income (loss)	**(5,383)**	(9,949)		
Total common stockholder's equity	**5,236,461**	4,854,310	**43.6**	43.6
Total Capitalization	**$12,004,038**	$11,144,228	**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, 2009, 2008, and 2007

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	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
			(in thousands)			
Balance at December 31, 2006	12,250	$490,000	$2,028,963	$1,516,245	$(2,921)	$4,032,287
Net income after dividends on preferred and preference stock	-	-	-	579,582	-	579,582
Issuance of common stock	5,725	229,000	-	-	-	229,000
Capital contributions from parent company	-	-	36,441	-	-	36,441
Other comprehensive income (loss)	-	-	-	-	(1,526)	(1,526)
Cash dividends on common stock	-	-	-	(465,000)	-	(465,000)
Other	-	-	(106)	5	-	(101)
Balance at December 31, 2007	17,975	719,000	2,065,298	1,630,832	(4,447)	4,410,683
Net income after dividends on preferred and preference stock	-	-	-	615,959	-	615,959
Issuance of common stock	7,500	300,000	-	-	-	300,000
Capital contributions from parent company	-	-	26,164	-	-	26,164
Other comprehensive income (loss)	-	-	-	-	(5,502)	(5,502)
Cash dividends on common stock	-	-	-	(491,300)	-	(491,300)
Other	-	-	-	(1,694)	-	(1,694)
Balance at December 31, 2008	**25,475**	**1,019,000**	**2,091,462**	**1,753,797**	**(9,949)**	**4,854,310**
Net income after dividends on preferred and preference stock	**-**	**-**	**-**	**669,536**	**-**	**669,536**
Issuance of common stock	**5,063**	**202,500**	**-**	**-**	**-**	**202,500**
Capital contributions from parent company	**-**	**-**	**28,356**	**-**	**-**	**28,356**
Other comprehensive income (loss)	**-**	**-**	**-**	**-**	**4,566**	**4,566**
Cash dividends on common stock	**-**	**-**	**-**	**(522,800)**	**-**	**(522,800)**
Other	**-**	**-**	**-**	**(7)**	**-**	**(7)**
Balance at December 31, 2009	**30,538**	**$1,221,500**	**$2,119,818**	**$1,900,526**	**$(5,383)**	**$5,236,461**

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2009, 2008, and 2007
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	2009	2008	2007
		(in thousands)	
Net income after dividends on preferred and preference stock	**$669,536**	$615,959	$579,582
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(1,943), $(4,297), and $(1,226), respectively	**(3,195)**	(7,068)	(2,017)
Reclassification adjustment for amounts included in net income, net of tax of $4,718, $952, and $298, respectively	**7,761**	1,566	491
Total other comprehensive income (loss)	**4,566**	(5,502)	(1,526)
Comprehensive Income	**$674,102**	$610,457	$578,056

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Alabama Power Company (the Company) is a wholly owned subsidiary of Southern Company, which is the parent company of 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, Georgia Power Company (Georgia 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 and wholesale customers within its traditional service area located in the State of Alabama in addition 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. Southern Nuclear operates and provides services to Southern Company's nuclear power plants, including the Company's Plant Farley.

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

The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the Alabama Public Service Commission (PSC). The Company follows accounting principles generally accepted in the United States and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires the use of estimates, and the actual results may differ from those estimates.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, purchasing, accounting and statistical analysis, finance and treasury, tax, information resources, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations and power pool transactions. Costs for these services amounted to $325 million, $321 million, and $299 million, during 2009, 2008, and 2007, respectively. 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 $183 million, $196 million, and $182 million, during 2009, 2008, and 2007, respectively.

The Company jointly owns Plant Greene County with Mississippi Power. The Company has an agreement with Mississippi Power under which the Company operates Plant Greene County, and Mississippi Power reimburses the Company for its proportionate share of non-fuel expenses, which were $10.2 million in 2009, $11.1 million in 2008, and $9.8 million in 2007. See Note 4 for additional information.

Southern Company's 30% ownership interest in Alabama Fuel Products, LLC (AFP), which produced synthetic fuel, was terminated in July 2006. The Company had an agreement with an indirect subsidiary of Southern Company that provided services for AFP. Under this agreement, the Company provided certain accounting functions, including processing and paying fuel transportation invoices, and the Company was reimbursed for its expenses. Amounts billed under this agreement totaled approximately $1.2 million and $58.1 million in 2008 and 2007, respectively. In addition, the Company purchased synthetic fuel from AFP for use at several of the Company's plants. Synthetic fuel purchases totaled $6.2 million and $462.1 million in 2008 and 2007, respectively.

The Company had an agreement with Southern Power under which the Company operated and maintained Plant Harris at cost. On August 1, 2007, that agreement was terminated and replaced with a service agreement under which the Company provides to Southern Power specifically requested services. In 2009, 2008, and 2007, the Company billed Southern Power $0.9 million, $0.9 million, and $2.4 million, respectively, under these agreements. Under a power purchase agreement (PPA) with Southern Power, the Company's purchased power costs from Plant Harris in 2009, 2008, and 2007 totaled $61.6 million, $63.2 million, and $66.3 million, respectively. The Company also provides the fuel, at cost, associated with the PPA. The fuel cost recognized by the Company was $62.5 million in 2009, $119.6 million in 2008, and $108.1 million in 2007. Additionally, the Company recorded $8.3 million of prepaid capacity expenses included in other deferred charges and other assets in the balance sheets at December 31, 2009, 2008, and 2007. See Note 3 under "Retail Regulatory Matters" and Note 7 under "Purchased Power Commitments" for additional information.

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

The traditional operating companies, including the Company, and Southern Power 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 rate 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:

	2009	2008	Note
	(in millions)		
Deferred income tax charges	**$ 387**	$ 363	(a)
Loss on reacquired debt	**74**	80	(b)
Vacation pay	**54**	53	(c, k)
Under/(over) recovered regulatory clause revenues	**(166)**	335	(d)
Fuel-hedging (realized and unrealized) losses	**45**	95	(e)
Other assets	**8**	7	(f, g)
Asset retirement obligations	**(43)**	18	(a)
Other cost of removal obligations	**(668)**	(635)	(a)
Deferred income tax credits	**(89)**	(90)	(a)
Fuel-hedging (realized and unrealized) gains	**(1)**	(4)	(e)
Mine reclamation and remediation	**(12)**	(14)	(h)
Nuclear outage	**(27)**	(8)	(d)
Deferred purchased power	**(8)**	(20)	(g)
Natural disaster reserve	**(75)**	(33)	(i)
Other liabilities	**(3)**	(4)	(d)
Underfunded retiree benefit plans	**657**	614	(j, k)
Total assets (liabilities), net	**$ 133**	$ 757	

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

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

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

(c) Recorded as earned by employees and recovered as paid, generally within one year. This includes both vacation and banked holiday pay.

(d) Recorded and recovered or amortized as approved or accepted by the Alabama PSC over periods not exceeding five years.
(e) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally does not exceed three years. Upon final settlement, actual costs incurred are recovered through the fuel cost recovery clause.
(f) Recorded as accepted by the Alabama PSC. Capitalized upon initialization of related construction projects.
(g) Recovered over the life of the PPA for periods up to 13 years.
(h) Recorded as accepted by the Alabama PSC. Mine reclamation and remediation liabilities will be settled following completion of the related activities.
(i) Recovered as storm restoration expenses are incurred, as approved by the Alabama PSC.
(j) Recovered and amortized over the average remaining service period which may range up to 14 years. See Note 2 for additional information.
(k) Not earning a return as offset in rate base by a corresponding asset or liability.

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 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 to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters" for additional information.

Revenues

Energy and other revenues are recognized as services are provided. Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract periods. Unbilled revenues are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. The Company continuously monitors the under/over recovered balances and files for revised rates as required or when management deems appropriate, depending on the rate. See Note 3 under "Retail Regulatory Matters – Fuel Cost Recovery" and "Retail Regulatory Matters – Rate CNP" for additional information.

The Company has a diversified base of customers. No single customer 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:

	2009	2008
	(in millions)	
Generation	**$ 9,627**	$ 9,096
Transmission	**2,702**	2,559
Distribution	**5,046**	4,827
General	**1,187**	1,141
Plant acquisition adjustment	**12**	12
Total plant in service	**$18,574**	$17,635

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense as incurred or performed with the exception of nuclear refueling costs, which are recorded in accordance with specific Alabama PSC orders. The Company accrues estimated nuclear refueling outage costs in advance of the unit's next refueling outage. The refueling cycle is 18 months for each unit. During 2009, the Company accrued $47.5 million for the applicable refueling cycles and paid $29.6 million for an outage at Plant Farley Unit 1. There was no outage at Plant Farley Unit 2 in 2009. At December 31, 2009, the reserve balance totaled $27.1 million and is included in the balance sheet in other regulatory liabilities.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.2% in 2009 and 2008 and 3.1% in 2007. Depreciation studies are conducted periodically to update the composite rates and the information is provided to the Alabama 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 is 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.

On June 25, 2009, the Company submitted an offer of settlement and stipulation to the FERC relating to the 2008 depreciation study that was filed in October 2008. The settlement offer withdraws the requests for authorization to use updated depreciation rates. In lieu of the new rates, the Company is using those depreciation rates employed prior and up to January 1, 2009 that were previously approved by the FERC. On September 30, 2009, the FERC issued an order approving the settlement offer.

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 Alabama 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.

The liability recognized to retire long-lived assets primarily relates to the Company's nuclear facility, Plant Farley. The fair value of assets legally restricted for settling retirement obligations related to nuclear facilities as of December 31, 2009 was $490 million. In addition, the Company has retirement obligations related to various landfill sites and underground storage tanks, asbestos removal, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities and certain wireless communication towers. 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 allowed removal costs in accordance with its regulatory treatment. Any differences 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, as ordered by the Alabama PSC, and are reflected in the balance sheets. See "Nuclear Decommissioning" for further information on amounts included in rates.

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

	2009	2008
	(in millions)	
Balance beginning of year	**$461**	$506
Liabilities incurred	**-**	-
Liabilities settled	**(1)**	(2)
Accretion	**31**	31
Cash flow revisions [a]	**-**	(74)
Balance end of year	**$491**	$461

(a) Updated based on results from 2008 Nuclear Decommissioning Study

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 Alabama 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. While the Company is allowed to prescribe an overall investment policy to the Funds' managers, the Company is 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 investment 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, unrealized, or identified as other-than-temporary, are recorded in the regulatory liability for asset retirement obligations in the balance sheets and are not included in net income or other comprehensive income. Fair value adjustments, realized gains, and other-than-temporary impairment losses are determined on a specific identification basis.

At December 31, 2009, investment securities in the Funds totaled $488.4 million consisting of equity securities of $345.6 million, debt securities of $134.3 million, and $8.5 million of other securities. At December 31, 2008, investment securities in the Funds totaled $402.9 million consisting of equity securities of $256.7 million, debt securities of $135.3 million, and $10.9 million of other securities. These amounts exclude receivables related to investment income and pending investment sales, and payables related to pending investment purchases.

Sales of the securities held in the Funds resulted in cash proceeds of $243.8 million, $299.6 million, and $333.4 million in 2009, 2008, and 2007, respectively, all of which were reinvested. For 2009, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $96.2 million, of which $79.9 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 $(134.4) million. Realized gains and other-than-temporary impairment losses were $34.6 million and $(37.2) million, respectively, in 2007. 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.

Amounts previously recorded in internal reserves are being transferred into the external trust funds over periods approved by the Alabama PSC. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed a plan with the NRC designed to ensure that, over time, the deposits and earnings of the external trust funds will provide the minimum funding amounts prescribed by the NRC.

At December 31, 2009, the accumulated provisions for decommissioning were as follows:

	(in millions)
External trust funds	$490
Internal reserves	25
Total	$515

Site study cost is the estimate to decommission the facility as of the site study year. The estimated costs of decommissioning based on the most current study performed in 2008 for Plant Farley was as follows:

Decommissioning periods:	
Beginning year	2037
Completion year	2065
	(in millions)
Site study costs:	
Radiated structures	$1,060
Non-radiated structures	72
Total	$1,132

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

For ratemaking purposes, the Company's decommissioning costs are based on the site study. Significant assumptions used to determine these costs for ratemaking were an inflation rate of 4.5% and a trust earnings rate of 7.0%. The next site study is expected to be conducted in 2013.

Amounts previously contributed to the external trust fund are currently projected to be adequate to meet the decommissioning obligations. The Company will continue to provide site specific estimates of the decommissioning costs and related projections of funds in the external trust to the Alabama PSC and, if necessary, would seek the Alabama PSC's approval to address any changes in a manner consistent with the NRC and other applicable requirements.

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 regulated facilities. While cash is not realized currently from such allowance, it increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation expense. The equity component of AFUDC is not included in calculating taxable income. All current construction costs are included in retail rates. The composite rate used to determine the amount of AFUDC was 9.2% in 2009 and 2008 and 9.4% in 2007. AFUDC, net of income tax, as a percent of net income after dividends on preferred and preference stock was 14.9% in 2009, 9.4% in 2008, and 8.0% in 2007.

Impairment of Long-Lived Assets and Intangibles

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

Natural Disaster Reserve

Based on an order from the Alabama PSC, the Company maintains a reserve for operations and maintenance expense to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly natural disaster reserve (NDR) charge to customers consisting of two components. The first component is intended to establish and maintain a target reserve balance of $75 million for future storms and is an on-going part of customer billing. The second component of the NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 24-month period. The Alabama PSC order gives the Company authority to record a deficit balance in the NDR when costs of storm damage exceed any established reserve balance. Absent further Alabama PSC approval, the maximum total NDR charge consisting of both components is $10 per month per non-residential customer account and $5 per month per residential customer account. The Company has discretionary authority to accrue certain additional amounts as circumstances warrant.

In addition to the monthly NDR charge, the Company accrued $39.6 million of discretionary reserve in 2009 resulting in an accumulated balance of approximately $75 million in the reserve for future storms as of December 31, 2009. This reserve is included in other regulatory liabilities, deferred in the balance sheets. Effective February 2010, billings will be reduced to $0.37 per month per non-residential customer account and $0.15 per month per residential customer account, consistent with the Alabama PSC order to maintain the target NDR balance. The Company has fully recovered its deferred storm costs; therefore, rates do not include the second component of the NDR charge.

As revenue from the NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, any change in revenue and expense will not have an effect on net income but will decrease operating cash flows related to the NDR charge in 2010 when compared to 2009.

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 cost 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 Alabama 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 exempt from fair value accounting requirements and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the Alabama PSC-approved fuel hedging program. This results in the deferral of related gains and losses in other comprehensive income or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts are marked to market through current period income and are recorded on a net basis in the statements of income. 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, 2009.

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. See Note 6 under "Long-Term Debt Payable to Affiliated Trusts" for additional information. 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 included in Long-term Debt in the balance sheets.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. The plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the defined benefit plan are expected for the year ending December 31, 2010. 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 trusts to the extent required by the Alabama PSC and the FERC. For the year ending December 31, 2010, postretirement trust contributions are expected to total approximately $11 million.

The measurement date for plan assets and obligations for 2009 and 2008 was December 31 while the measurement date for prior years was September 30. Pursuant to accounting standards related to defined postretirement benefit plans, the Company was required to change the measurement date for its defined postretirement benefit plans from September 30 to December 31 beginning with the year ended December 31, 2008. As permitted, the Company adopted the measurement date provisions effective January 1, 2008 resulting in an increase in long-term liabilities of $5 million and an increase in prepaid pension costs of approximately $11 million.

Pension Plans

The total accumulated benefit obligation for the pension plans was $1.6 billion in 2009 and $1.4 billion in 2008. Changes during the plan year ended December 31, 2009 and the 15-month period ended December 31, 2008 in the projected benefit obligations and the fair value of plan assets were as follows:

	2009	2008
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$1,460**	$1,420
Service cost	**34**	43
Interest cost	**96**	109
Benefits paid	**(77)**	(94)
Actuarial loss (gain)	**162**	(18)
Balance at end of year	**1,675**	1,460
Change in plan assets		
Fair value of plan assets at beginning of year	**1,539**	2,318
Actual return (loss) on plan assets	**245**	(692)
Employer contributions	**5**	7
Benefits paid	**(77)**	(94)
Fair value of plan assets at end of year	**1,712**	1,539
Prepaid pension asset, net	**$ 37**	$ 79

At December 31, 2009, the projected benefit obligations for the qualified and non-qualified pension plans were $1.6 billion and $95 million, respectively. All pension plan assets are related to the qualified pension plan.

Pension plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). 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 horizon. The primary goal of the study was to maximize plan funded status. The Company's investment policy covers 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 actual composition of the Company's pension plan assets as of the end of the year, along with the targeted mix of assets, is presented below:

	Target	**2009**	2008
Domestic equity	29%	**33%**	34%
International equity	28	**29**	23
Fixed income	15	**15**	14
Special situations	3	**-**	-
Real estate investments	15	**13**	19
Private equity	10	**10**	10
Total	100%	**100%**	100%

The investment strategy for plan assets related to the Company's defined benefit 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.

Detailed below is a description of the investment strategies for each major asset category disclosed above:

- ***Domestic equity.*** This portion of the portfolio comprises a mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes managed both actively and through passive index approaches.
- ***International equity.*** This portion of the portfolio is actively managed with a blend of growth stocks and value stocks with both developed and emerging market exposure.
- ***Fixed income.*** This portion of the portfolio is actively managed through an allocation to long-dated, investment grade corporate and government bonds.
- ***Special situations.*** Though currently unfunded, this portion of the portfolio was 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.*** Assets in this portion of the portfolio are invested 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.*** This portion of the portfolio generally consists of investments in private partnerships that invest in private or public securities typically through privately negotiated and/or structured transactions. Leveraged buyouts, venture capital, and distressed debt are examples of investment strategies within this category.

The fair values of pension plan assets as of December 31, 2009 and 2008 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, 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*	$339	$141	$ -	$ 480
International equity*	439	44	-	483
Fixed income:				
U.S. Treasury, government, and agency bonds	-	127	-	127
Mortgage- and asset-backed securities	-	34	-	34
Corporate bonds	-	85	-	85
Pooled funds	-	3	-	3
Cash equivalents and other	1	104	-	105
Special situations	-	-	-	-
Real estate investments	53	-	166	219
Private equity	-	-	169	169
Total	$832	$538	$335	$1,705
Liabilities:				
Derivatives	(1)	-	-	(1)
Total	$831	$538	$335	$1,704

*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, 2008:	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*	$318	$129	$ -	$ 447
International equity*	285	26	-	311
Fixed income:				
U.S. Treasury, government, and agency bonds	-	133	-	133
Mortgage- and asset-backed securities	-	63	-	63
Corporate bonds	-	86	-	86
Pooled funds	-	1	-	1
Cash equivalents and other	7	61	-	68
Special situations	-	-	-	-
Real estate investments	43	-	254	297
Private equity	-	-	148	148
Total	$653	$499	$402	$1,554
Liabilities:				
Derivatives	(2)	-	-	(2)
Total	$651	$499	$402	$1,552

*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, 2009 and 2008 are as follows:

	2009		2008	
	Real Estate Investments	**Private Equity**	**Real Estate Investments**	**Private Equity**
	(in millions)			
Beginning balance	**$254**	**$148**	$316	$157
Actual return on investments:				
Related to investments held at year end	**(72)**	**13**	(51)	(43)
Related to investments sold during the year	**(20)**	**3**	1	8
Total return on investments	**(92)**	**16**	(50)	(35)
Purchases, sales, and settlements	**4**	**5**	(12)	26
Transfers into/out of Level 3	**-**	**-**	-	-
Ending balance	**$166**	**$169**	$254	$148

The fair values presented above are prepared in accordance with applicable accounting standards regarding fair value. For purposes of determining the fair value of the pension 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 using 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.

Amounts recognized in the consolidated balance sheets related to the Company's pension plans consist of:

	2009	2008
	(in millions)	
Prepaid pension costs	**$133**	$166
Other regulatory assets, deferred	**549**	479
Other current liabilities	**(6)**	(6)
Employee benefit obligations	**(90)**	(81)

Presented below are the amounts included in regulatory assets at December 31, 2009 and 2008 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 2010.

	Prior Service Cost	**Net (Gain)Loss**
	(in millions)	
Balance at December 31, 2009:		
Regulatory assets	**$50**	**$499**
Balance at December 31, 2008:		
Regulatory assets	$58	$421
Estimated amortization in net periodic pension cost in 2010:		
Regulatory assets	$ 9	$ 2

The changes in the balances of regulatory assets and regulatory liabilities related to the defined benefit pension plans for the year ended December 31, 2009 and the 15 months ended December 31, 2008 are presented in the following table:

	Regulatory Assets	Regulatory Liabilities
	(in millions)	
Balance at December 31, 2007	$ 43	$(423)
Net loss	441	433
Change in prior service costs	-	-
Reclassification adjustments:		
Amortization of prior service costs	(2)	(10)
Amortization of net gain	(3)	-
Total reclassification adjustments	(5)	(10)
Total change	436	423
Balance at December 31, 2008	479	-
Net loss	**79**	-
Change in prior service costs	**1**	-
Reclassification adjustments:		
Amortization of prior service costs	**(9)**	-
Amortization of net gain	**(1)**	-
Total reclassification adjustments	**(10)**	-
Total change	**70**	-
Balance at December 31, 2009	**$549**	**$ -**

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

	2009	2008	2007
		(in millions)	
Service cost	**$ 34**	$ 35	$ 35
Interest cost	**96**	87	82
Expected return on plan assets	**(164)**	(160)	(146)
Recognized net (gain) loss	**1**	2	2
Net amortization	**9**	10	10
Net periodic pension (income)	**$ (24)**	$ (26)	$ (17)

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, 2009, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2010	$ 87
2011	91
2012	95
2013	101
2014	108
2015 to 2019	610

Other Postretirement Benefits

Changes during the plan year ended December 31, 2009 and the 15-month period ended December 31, 2008 in the accumulated postretirement benefit obligations (APBO) and in the fair value of plan assets were as follows:

	2009	2008
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 446**	$ 480
Service cost	**6**	9
Interest cost	**29**	37
Benefits paid	**(26)**	(30)
Actuarial loss (gain)	**19**	(53)
Plan amendments	**(15)**	-
Retiree drug subsidy	**2**	3
Balance at end of year	**461**	446
Change in plan assets		
Fair value of plan assets at beginning of year	**252**	297
Actual return (loss) on plan assets	**47**	(75)
Employer contributions	**20**	57
Benefits paid	**(24)**	(27)
Fair value of plan assets at end of year	**295**	252
Accrued liability (recognized in the balance sheet)	**$(166)**	$(194)

Other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code. The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. 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 actual composition of the Company's other postretirement benefit plan assets as of the end of the year, along with the targeted mix of assets, is presented below:

	Target	2009	2008
Domestic equity	47%	**42%**	31%
International equity	12	**16**	13
Domestic fixed income	32	**35**	46
Special situations	1	**-**	-
Real estate investments	5	**4**	7
Private equity	3	**3**	3
Total	100%	**100%**	100%

Detailed below is a description of the investment strategies for each major asset category disclosed above:

- ***Domestic equity.*** This portion of the portfolio comprises a mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes managed both actively and through passive index approaches.
- ***International equity.*** This portion of the portfolio is actively managed with a blend of growth stocks and value stocks with both developed and emerging market exposure.
- ***Fixed income.*** This portion of the portfolio is comprised of domestic bonds.
- ***Special situations.*** Though currently unfunded, this portion of the portfolio was 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.
- ***Trust-owned life insurance.*** Some of the Company's taxable trusts invest in these investments in order to minimize the impact of taxes on the portfolio.
- ***Real estate investments.*** Assets in this portion of the portfolio are invested 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.*** This portion of the portfolio generally consists of investments in private partnerships that invest in private or public securities typically through privately negotiated and/or structured transactions. Leveraged buyouts, venture capital, and distressed debt are examples of investment strategies within this category.

The fair values of other postretirement benefit plan assets as of December 31, 2009 and 2008 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases.

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*	$54	$ 8	$ -	$ 62
International equity*	24	2	-	26
Fixed income:				
U.S. Treasury, government, and agency bonds	-	7	-	7
Mortgage- and asset-backed securities	-	2	-	2
Corporate bonds	-	5	-	5
Pooled funds	-	-	-	-
Cash equivalents and other	-	23	-	23
Trust-owned life insurance	-	144	-	144
Special situations	-	-	-	-
Real estate investments	3	-	9	12
Private equity	-	-	10	10
Total	$81	$191	$19	$291

*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, 2008:	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*	$33	$ 7	$ -	$ 40
International equity*	16	1	-	17
Fixed income:				
U.S. Treasury, government, and agency bonds	-	7	-	7
Mortgage- and asset-backed securities	-	4	-	4
Corporate bonds	-	5	-	5
Pooled funds	-	-	-	-
Cash equivalents and other	-	48	-	48
Trust-owned life insurance	-	105	-	105
Special situations	-	-	-	-
Real estate investments	2	-	15	17
Private equity	-	-	8	8
Total	$51	$177	$23	$251

*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, 2009 and 2008 are as follows:

	2009		2008	
	Real Estate Investments	**Private Equity**	**Real Estate Investments**	**Private Equity**
		(in millions)		
Beginning balance	**$15**	**$8**	$17	$9
Actual return on investments:				
Related to investments held at year end	**(5)**	**2**	(2)	(2)
Related to investments sold during the year	**(1)**	**-**	-	-
Total return on investments	**(6)**	**2**	(2)	(2)
Purchases, sales, and settlements	**-**	**-**	-	1
Transfers into/out of Level 3	**-**	**-**	-	-
Ending balance	**$9**	**$10**	$15	$8

The fair values presented above are prepared in accordance with applicable accounting standards regarding fair value. For purposes of determining the fair value of the pension 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 using 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.

Amounts recognized in the balance sheets related to the Company's other postretirement benefit plans consist of:

	2009	2008
	(in millions)	
Regulatory assets	**$ 108**	$ 135
Employee benefit obligations	**(166)**	(194)

Presented below are the amounts included in regulatory assets at December 31, 2009 and 2008 related to the other postretirement benefit plans that had not yet been recognized in net periodic postretirement benefit cost along with the estimated amortization of such amounts for 2010.

	Prior Service Cost	**Net (Gain)Loss**	**Transition Obligation**
		(in millions)	
Balance at December 31, 2009:			
Regulatory asset	**$33**	**$67**	**$ 8**
Balance at December 31, 2008:			
Regulatory asset	$49	$71	$15
Estimated amortization as net periodic postretirement cost in 2010:			
Regulatory asset	$ 4	$ -	$ 3

The changes in the balance of regulatory assets related to the other postretirement benefit plans for the plan year ended December 31, 2009 and the 15 months ended December 31, 2008 are presented in the following table:

	Regulatory Assets
	(in millions)
Balance at December 31, 2007	$ 95
Net loss	50
Change in prior service costs/transition obligation	-
Reclassification adjustments:	
Amortization of transition obligation	(5)
Amortization of prior service costs	(5)
Amortization of net gain	-
Total reclassification adjustments	(10)
Total change	40
Balance at December 31, 2008	135
Net gain	**(4)**
Change in prior service costs/transition obligation	**(15)**
Reclassification adjustments:	
Amortization of transition obligation	**(4)**
Amortization of prior service costs	**(4)**
Amortization of net gain	-
Total reclassification adjustments	**(8)**
Total change	**(27)**
Balance at December 31, 2009	**$108**

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

	2009	2008	2007
		(in millions)	
Service cost	**$ 6**	$ 7	$ 7
Interest cost	**29**	29	28
Expected return on plan assets	**(24)**	(22)	(19)
Net amortization	**8**	9	11
Net postretirement cost	**$ 19**	$ 23	$ 27

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, 2009, 2008, and 2007 by approximately $9.0 million, $10.7 million, and $10.7 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 postretirement plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Act as follows:

	Benefit Payments	**Subsidy Receipts**	**Total**
		(in millions)	
2010	$ 29	$ (3)	$ 26
2011	32	(3)	29
2012	34	(3)	31
2013	36	(4)	32
2014	37	(4)	33
2015 to 2019	194	(28)	166

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 2006 for the 2007 plan year using a discount rate of 6.00% and an annual salary increase of 3.50%.

	2009	2008	2007
Discount rate:			
Pension plans	**5.93%**	6.75%	6.30%
Other postretirement benefit plans	**5.84**	6.75	6.30
Annual salary increase	**4.18**	3.75	3.75
Long-term return on plan assets:			
Pension plans	**8.50**	8.50	8.50
Other postretirement benefit plans	**7.52**	7.66	7.68

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 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 APBO was a weighted average medical care cost trend rate of 8.50% for 2010, decreasing gradually to 5.25% through the year 2016 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, 2009 as follows:

	1 Percent Increase	**1 Percent Decrease**
	(in millions)	
Benefit obligation	$29	$27
Service and interest costs	2	2

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution up to 6% of an employee's base salary. Total matching contributions made to the plan for 2009, 2008, and 2007 were $19 million, $18 million, and $17 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 United States. 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. These actions were filed concurrently with the issuance of notices of violation of the NSR provisions to each of the traditional operating companies. After the Company was dismissed from the original action, the EPA filed a separate action in January 2001 against the Company in the U.S. District Court for the Northern District of Alabama. In the lawsuit against the Company, the EPA alleges that NSR violations occurred at five coal-fired generating facilities operated by the Company. The civil action requests 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 Georgia Power, 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 the Company and the EPA, resolving a portion of the Company's 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 the Company 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. The decision did not resolve the case, which remains ongoing.

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.

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, on September 21, 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 November 5, 2009, the defendants, including Southern Company, sought rehearing en banc, and the court's ruling is subject to potential appeal. Therefore, 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. On September 30, 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. On November 5, 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. 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 courts have recently determined that private parties and states have standing to bring such claims. For example, on October 16, 2009, the U.S. Court of Appeals for the Fifth Circuit reversed the U.S. District Court for the Southern District of Mississippi's dismissal of private party claims against certain oil, coal, chemical, and utility companies alleging damages as a result of Hurricane Katrina. In reversing the dismissal, the U.S. Court of Appeals for the Fifth Circuit held that plaintiffs have standing to assert their nuisance, trespass, and negligence claims and none of these claims are barred by the political question doctrine. The Company is not currently a party to this litigation but was named as a defendant in an amended complaint which was rendered moot in August 2007 by the U.S. District Court for the Southern District of Mississippi when such court dismissed the original matter. The ultimate outcome of this matter 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 may also incur substantial costs to clean up properties.

FERC Matters

Market-Based Rate Authority

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

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation market power within its retail service territory. The ability to charge market-based rates in other markets was not an issue in the proceeding. Any new market-based rate sales by the Company in Southern Company's retail service territory entered into during a 15-month refund period that ended in May 2006 could have been subject to refund to a cost-based rate level.

On December 23, 2009, Southern Company and the FERC trial staff reached an agreement in principle that would resolve the proceeding in its entirety. The agreement does not reflect any finding or suggestion that the Company possesses or has exercised any market power. The agreement likewise does not require the Company to make any refunds related to sales during the 15-month refund period. Under the agreement, the Company will donate $0.6 million to nonprofit organizations in the State of Alabama for the purpose of offsetting the electricity bills of low-income retail customers. The agreement is subject to review and approval by the FERC.

Intercompany Interchange Contract

The Company's generation fleet is operated under the Intercompany Interchange Contract (IIC), as approved by the FERC. In May 2005, the FERC initiated a new proceeding to examine (1) the provisions of the IIC among the traditional operating companies (including the Company), Southern Power, and SCS, as agent, under the terms of which the power pool of Southern Company is operated, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining Southern Power as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of Southern Power, the FERC authorized Southern Power's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct.

In October 2006, the FERC issued an order accepting a settlement resolving the proceeding subject to Southern Company's agreement to accept certain modifications to the settlement's terms. Southern Company notified the FERC that it accepted the modifications. The modifications largely involve functional separation and information restrictions related to marketing activities conducted on behalf of Southern Power. In November 2006, Southern Company filed with the FERC a compliance plan in connection with the order. In April 2007, the FERC approved, with certain modifications, the plan submitted by Southern Company. Implementation of the plan did not have a material impact on the Company's financial statements. In November 2007, Southern Company notified the FERC that the plan had been implemented. In December 2008, the FERC division of audits issued for public comment its final audit report pertaining to compliance implementation and related matters. No comments were submitted challenging the audit report's findings of Southern Company's compliance. The proceeding remains open pending a decision from the FERC regarding the audit report.

Nuclear Fuel Disposal Costs

The Company has a contract with the United States, acting through the U.S. Department of Energy (DOE), that provides for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent nuclear fuel in 1998 as required by the contract, and the Company is pursuing legal remedies against the government for breach of contract.

In July 2007, the U.S. Court of Federal Claims awarded the Company approximately $17 million, representing substantially all of the direct costs of the expansion of spent nuclear fuel storage facilities at Plant Farley 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. In April 2008, the U.S. Court of Appeals for the Federal Circuit granted the government's motion to stay the appeal pending the court's decisions in three other similar cases already on appeal. Those cases were decided in August 2008. The U.S. Court of Appeals for the Federal Circuit has left the stay of appeals in place pending the decision in an appeal of another case involving spent nuclear fuel contracts.

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. In October 2008, the U.S. Court of Appeals for the Federal Circuit denied a similar request by the government to stay this proceeding. 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, 2009 for either claim. The final outcome of these matters cannot be determined at this time, but no material impact on net income is expected as any damage amounts collected from the government are expected to be returned to customers.

An on-site dry spent fuel storage facility at Plant Farley is operational and can be expanded to accommodate spent fuel through the expected life of the plant.

Retail Regulatory Matters

Rate RSE

Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate adjustments for any two-year period, when averaged together, cannot exceed 4.0% per year and any annual adjustment is limited to 5.0%. Retail rates remain unchanged when the retail return on common equity is projected to be between 13.0% and 14.5%. If the Company's actual retail return on common equity is above the allowed equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail return on common equity fall below the allowed equity return range.

In October 2008, the Alabama PSC approved a corrective rate package, effective January 2009, that primarily provides for adjustments associated with customer charges to certain existing rate structures. The Company agreed to a moratorium on any increase in rates in 2009 under the Rate RSE.

On December 1, 2009, the Company made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2010. The Rate RSE increase for 2010 is 3.24%, or $152 million annually, and was effective in January 2010. The revenue adjustment under the Rate RSE is largely attributable to the costs associated with fossil capacity which is currently dedicated to certain long-term wholesale contracts that expire during 2010. Retail cost of service for 2010 reflects the costs for that portion of the year in which this capacity is no longer committed to wholesale. In an Alabama PSC order dated January 5, 2010, the Alabama PSC acknowledged that a full calendar year of costs for these units would be reflected in the Rate RSE calculation beginning in 2011 and thereafter. Under the terms of Rate RSE, the maximum increase for 2011 cannot exceed 4.76%.

Rate CNP

The Company's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service and the recovery of retail costs associated with certificated PPAs under a Rate CNP. There was no adjustment to the Rate CNP to recover certificated PPA costs in 2007, 2008, or 2009. Effective April 2010, Rate CNP will be reduced approximately $70 million annually, primarily due to the expiration on May 31, 2010, of the PPA with Southern Power covering the capacity of Plant Harris Unit 1.

Rate CNP also allows for the recovery of the Company's retail costs associated with environmental laws, regulations, or other such mandates. The rate mechanism is based on forward looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on invested capital. Retail rates increased approximately 0.6% in January 2007 and 2.4% in January 2008 due to environmental costs. In October 2008, the Company agreed to defer collection of any increase in rates under this portion of Rate CNP, which permits recovery of costs associated with environmental laws and regulations, from 2009 until 2010. The deferral of the retail rate adjustments had an immaterial impact on annual cash flows, and had no significant effect on the Company's revenues or net income. On December 1, 2009, the Company made its Rate CNP environmental submission of projected data for calendar year 2010, resulting in an increase to retail rates of approximately 4.3%, or an additional $195 million annually, based upon projected billings. Under the terms of the rate mechanism, this adjustment became effective in January 2010. The Rate CNP environmental adjustment is primarily attributable to scrubbers being placed in service during 2010 at four of the Company's generating units.

Fuel Cost Recovery

The Company has established fuel cost recovery rates under Rate ECR approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. The Company, along with the Alabama PSC, will continue to monitor the over recovered fuel cost balance to determine whether an additional adjustment to billing rates is required.

In June 2007, the Alabama PSC ordered the Company to increase its Rate ECR factor to 3.100 cents per kilowatt-hour (KWH) effective with billings beginning July 2007. In October 2008, the Alabama PSC approved an increase in the Company's Rate ECR factor to 3.983 cents per KWH effective with billings beginning October 2008.

On June 2, 2009, the Alabama PSC approved a decrease in the Company's Rate ECR factor to 3.733 cents per KWH for billings beginning June 9, 2009. On December 1, 2009, the Alabama PSC approved a decrease in the Company's Rate ECR factor to 2.731 cents per KWH for billings beginning January 2010 through December 2011. The Alabama PSC further approved an additional reduction in the Rate ECR factor of 0.328 cents per KWH for the billing months of January 2010 through December 2010 resulting in a Rate ECR factor of 2.403 cents per KWH for such 12-month period. For billing months beginning January 2012, the Rate ECR factor shall be 5.910 cents per KWH, absent a contrary order by the Alabama PSC. Rate ECR revenues, as recorded on the financial statements, are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, the approved decreases in the Rate ECR factor will have no significant effect on the Company's net income, but will decrease operating cash flows related to fuel cost recovery in 2010 when compared to 2009.

As of December 31, 2009, the Company had an over recovered fuel balance of approximately $199.6 million, of which approximately $22.1 million is included in deferred over recovered regulatory clause revenues in the balance sheets. As of December 31, 2008, the Company had an under recovered fuel balance of approximately $305.8 million, of which approximately $180.9 million is included in deferred under recovered regulatory clause revenues in the balance sheets. These classifications are based on estimates, which include such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any return of the over recovered fuel costs or recovery of under recovered fuel costs.

Natural Disaster Reserve

Based on an order from the Alabama PSC, the Company maintains a reserve for operations and maintenance expense to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly NDR charge to customers consisting of two components. The first component is intended to establish and maintain a target reserve balance of $75 million for future storms and is an on-going part of customer billing. The second component of the NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 24-month period. The Alabama PSC order gives the Company authority to record a deficit balance in the NDR when costs of storm damage exceed any established reserve balance. Absent further Alabama PSC approval, the maximum total NDR charge consisting of both components is $10 per month per non-residential customer account and $5 per month per residential customer account. The Company has discretionary authority to accrue certain additional amounts as circumstances warrant.

In addition to the monthly NDR charge, the Company accrued $39.6 million of discretionary reserve in 2009 resulting in an accumulated balance of approximately $75 million in the reserve for future storms as of December 31, 2009. This reserve is included in other regulatory liabilities, deferred in the balance sheets. Effective February 2010, billings will be reduced to $0.37 per month per non-residential customer account and $0.15 per month per residential customer account, consistent with the Alabama PSC order to maintain the target NDR balance. The Company has fully recovered its deferred storm costs, therefore, rates do not include the second component of the NDR charge.

As revenue from the NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, any change in revenue and expense will not have an effect on net income but will decrease operating cash flows related to the NDR charge in 2010 when compared to 2009.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Georgia Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 megawatts, as well as associated transmission facilities. The capacity of these units is sold equally to the Company and Georgia Power under a contract which, in substance, requires payments sufficient to provide for the operating expenses, taxes, interest expense, and a return on equity, whether or not SEGCO has any capacity and energy available. The term of the contract extends automatically for two-year periods, subject to either party's right to cancel upon two years' notice. The Company's share of purchased power totaled $82.1 million in 2009, $124 million in 2008, and $105 million in 2007, and is included in "Purchased power from affiliates" in the statements of income. The Company accounts for SEGCO using the equity method.

In addition, the Company has guaranteed unconditionally the obligation of SEGCO under an installment sale agreement for the purchase of certain pollution control facilities at SEGCO's generating units, pursuant to which $24.5 million principal amount of pollution control revenue bonds are outstanding. Also, the Company has guaranteed $50 million principal amount of unsecured senior notes issued by SEGCO for general corporate purposes. Georgia Power has agreed to reimburse the Company for the pro rata portion of such obligations corresponding to its then proportionate ownership of stock of SEGCO if the Company is called upon to make such payment under its guaranty.

At December 31, 2009, the capitalization of SEGCO consisted of $85 million of equity and $74 million of long-term debt on which the annual interest requirement is $3.2 million. SEGCO paid no dividends in 2009, $7.8 million in 2008, and $2.6 million in 2007, of which one-half of each was paid to the Company. In addition, the Company recognizes 50% of SEGCO's net income.

In addition to the Company's ownership of SEGCO, the Company's percentage ownership and investment in jointly-owned coal-fired generating plants at December 31, 2009 is as follows:

Facility	Total Megawatt Capacity	Company Ownership	Company Investment	Accumulated Depreciation
			(in millions)	
Greene County	500	60.00% (1)	$ 137	$ 71
Plant Miller Units 1 and 2	1,320	91.84% (2)	1,063	449

(1) Jointly owned with an affiliate, Mississippi Power.
(2) Jointly owned with PowerSouth.

At December 31, 2009, the Company's Plant Miller portion of construction work in progress was $243.6 million.

The Company has contracted to operate and maintain the jointly owned facilities as agent for their co-owners. The Company's proportionate share of its plant operating expenses is included in operating expenses in the statements of income 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. In addition, the Company files a separate company income tax return for the State of Tennessee.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2009	2008	2007
		(in millions)	
Federal –			
Current	$374	$198	$287
Deferred	(41)	121	17
	$333	$319	$304
State –			
Current	$ 76	$ 43	$ 43
Deferred	(25)	6	4
	51	49	47
Total	$384	$368	$351

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:

	2009	2008
	(in millions)	
Deferred tax liabilities:		
Accelerated depreciation	$2,010	$1,908
Property basis differences	376	343
Premium on reacquired debt	30	33
Pension and other benefits	184	175
Fuel clause under recovered	-	140
Regulatory assets associated with employee benefit obligations	295	286
Regulatory assets associated with asset retirement obligations	208	199
Other	82	67
Total	3,185	3,151
Deferred tax assets:		
Federal effect of state deferred taxes	88	126
State effect of federal deferred taxes	107	104
Unbilled revenue	29	34
Storm reserve	23	4
Pension and other benefits	334	330
Other comprehensive losses	9	13
Fuel clause over recovered	75	
Asset retirement obligations	208	199
Other	93	82
Total	966	892
Total deferred tax liabilities, net	2,219	2,259
Portion included in current assets (liabilities), net	74	(16)
Accumulated deferred income taxes in the balance sheets	$2,293	$2,243

At December 31, 2009, the Company's tax-related regulatory assets and liabilities were $387 million and $89 million, respectively. 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. These liabilities are attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized investment tax credits.

In accordance with regulatory requirements, deferred investment tax credits are amortized over the lives of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $8.0 million in each of 2009, 2008, and 2007. At December 31, 2009, all investment tax credits available to reduce federal income taxes payable had been utilized.

Effective Tax Rate

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

	2009	2008	2007
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**3.0**	3.1	3.2
Non-deductible book depreciation	**0.8**	0.9	0.9
Differences in prior years' deferred and current tax rates	**(0.2)**	(0.1)	(0.2)
AFUDC-equity	**(2.5)**	(1.6)	(1.3)
Production activities deduction	**(0.8)**	(0.5)	(0.6)
Other	**(0.2)**	(0.8)	(0.7)
Effective income tax rate	**35.1%**	36.0%	36.3%

AFUDC increased in 2009 due to increases in the amount of construction work in progress related to environmental mandates at generating facilities and transmission, distribution, and general plant projects compared to the prior years. See Note 1 under "Allowance for Funds Used During Construction (AFUDC)" for additional information.

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 the Internal Revenue Code Section 199 (production activities deduction). The deduction is equal to a stated percentage of qualified production activities net income. The percentage is phased in over the years 2005 through 2010 with a 3% rate applicable to the years 2005 and 2006, a 6% rate applicable for the years 2007 through 2009, and a 9% rate thereafter. The IRS has not clearly defined a methodology for calculating this deduction. However, Southern Company reached an agreement with the IRS on a calculation methodology and signed a closing agreement in December 2008. Therefore, in 2008, the Company reversed the unrecognized tax benefit related to the calculation methodology and adjusted the deduction for all previous years to conform to the agreement which resulted in a decrease in the 2008 deduction when compared to the 2007 deduction. Certain aspects of the production activities deduction remain unresolved. The net impact of the reversal of the unrecognized tax benefits combined with the application of the new methodology had no material effect on the Company's financial statements.

Unrecognized Tax Benefits

For 2009, the total amount of unrecognized tax benefits increased by $3 million, resulting in a balance of $6 million as of December 31, 2009.

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

	2009	2008	2007
		(in millions)	
Unrecognized tax benefits at beginning of year	**$3**	$5	$1
Tax positions from current periods	**2**	1	2
Tax positions from prior periods	**1**	(2)	2
Reductions due to settlements	**-**	(1)	-
Reductions due to expired statute of limitations	**-**	-	-
Balance at end of year	**$6**	$3	$5

The tax positions from current periods increase for 2009 relate primarily to the production activities deduction tax position and other miscellaneous uncertain tax positions. The tax positions increase from prior periods for 2009 relates primarily to the production activities deduction tax position. See "Effective Tax Rate" above for additional information.

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

	2009	2008	2007
		(in millions)	
Tax positions impacting the effective tax rate	**$6**	$3	$5
Tax positions not impacting the effective tax rate	-	-	-
Balance of unrecognized tax benefits	**$6**	$3	$5

Accrued interest for unrecognized tax benefits was as follows:

	2009	2008	2007
		(in millions)	
Interest accrued at beginning of year	**$0.3**	$0.4	$ -
Interest reclassified due to settlements	-	(0.3)	-
Interest accrued during the year	-	0.2	0.4
Balance at end of year	**$0.3**	$0.3	$0.4

The Company classifies interest on tax uncertainties as interest expense. The Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized benefit with respect to a majority of the Company's unrecognized tax positions will significantly increase or decrease within the next 12 months. The possible conclusion or settlement of state audits could 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 2004. 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 Payable. 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, 2009, 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

At December 31, 2009, the Company had a scheduled maturity of senior notes due within one year totaling $100 million. At December 31, 2008, the Company had scheduled maturities and redemptions of senior notes due within one year totaling $250 million.

Maturities of senior notes through 2014 applicable to total long-term debt are as follows: $100 million in 2010; $200 million in 2011; $500 million in 2012; $250 million in 2013; and none in 2014.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds or installment purchases of solid waste disposal facilities financed by funds derived from sales by public authorities of revenue bonds. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The Company incurred obligations related to the issuance of $78.5 million of pollution control revenue bonds in 2009. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

Senior Notes

The Company issued a total of $500 million of unsecured senior notes in 2009. The proceeds of these issuances were used to repay short-term indebtedness and for other general corporate purposes, including the Company's continuous construction program.

At December 31, 2009 and 2008, the Company had $4.8 billion and $4.6 billion, respectively, of senior notes outstanding. These senior notes are effectively subordinate to all secured debt of the Company which amounted to approximately $153 million at December 31, 2009.

Preference and Common Stock

In 2009, the Company issued no new shares of preference stock. The Company issued 5,062,500 new shares of common stock to Southern Company at $40.00 per share and realized proceeds of $202.5 million. The proceeds of these issuances were used for general corporate purposes.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized and outstanding. The Company's preferred stock and Class A preferred stock, without preference between classes, rank senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. The preferred stock and Class A preferred stock of the Company contains a feature that allows the holders to elect a majority of the Company's board of directors if dividends are not paid for four consecutive quarters. Because such a potential redemption-triggering event is not solely within the control of the Company, the preferred stock and Class A preferred stock is presented as "Redeemable Preferred Stock" in a manner consistent with temporary equity under applicable accounting standards. The preference stock does not contain such a provision that would allow the holders to elect a majority of the Company's board. 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 preferred stock, 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).

Dividend Restrictions

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

Assets Subject to Lien

The Company has granted liens on certain property in connection with the issuance of certain series of pollution control revenue bonds with an outstanding principal amount of $153 million as of December 31, 2009.

Bank Credit Arrangements

The Company maintains committed lines of credit in the amount of $1.3 billion, of which $481 million will expire at various times during 2010, $25 million will expire in 2011, and $765 will expire in 2012. $372 million of the credit facilities expiring in 2010 allow for the execution of one-year term loans. These credit facilities provide liquidity support to the Company's commercial paper borrowings and $608 million are dedicated to funding purchase obligations relating to variable rate pollution control revenue bonds. Subsequent to December 31, 2009, two remarketings of pollution control revenue bonds increased that amount to $744 million.

Most of the credit arrangements require payment of a commitment fee based on the unused portion of the commitment or the maintenance of compensating balances with the banks. Commitment fees average less than ¼ of 1% for the Company. Compensating balances are not legally restricted from withdrawal.

Most of the Company's credit arrangements with banks have covenants that limit the Company's debt to 65% of total capitalization, as defined in the arrangements. For purposes of calculating these covenants, long-term notes payable to affiliated trusts are excluded from debt but included in capitalization. Exceeding this debt level would result in a default under the credit arrangements. At December 31, 2009, the Company was in compliance with the debt limit covenants. In addition, the credit arrangements typically contain cross default provisions that would be triggered if the Company defaulted on other indebtedness (including guarantee obligations) above a specified threshold. None of the arrangements contain material adverse change clauses at the time of borrowings.

The Company borrows through commercial paper programs that have the liquidity support of committed bank credit arrangements. In addition, the Company borrows from time to time through uncommitted credit arrangements. As of December 31, 2009, the Company had no commercial paper outstanding. As of December 31, 2008, the Company had $25 million of commercial paper outstanding. During 2009 and 2008, the peak amount outstanding for short-term borrowings was $237 million and $301 million, respectively. The average amount outstanding in 2009 and 2008 was $30 million and $40 million, respectively. The average annual interest rate on short-term borrowings was 0.23% in 2009 and 2.31% in 2008. Short-term borrowings are included in notes payable in the balance sheets.

At December 31, 2009, the Company had regulatory approval to have outstanding up to $2.0 billion of short-term borrowings.

7. COMMITMENTS

Construction Program

The Company is engaged in continuous construction programs, currently estimated to total $1.0 billion in 2010, $1.0 billion in 2011, and $1.1 billion in 2012. These amounts include $73 million, $48 million, and $51 million for 2010, 2011, and 2012, respectively, for construction expenditures related to contractual purchase commitments for nuclear fuel included under "Fuel Commitments." The construction programs are 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; revised load growth estimates; changes in environmental statutes and regulations; changes in nuclear plants to meet new regulatory requirements; changes in FERC rules and regulations; Alabama PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; 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, 2009, significant purchase commitments were outstanding in connection with the construction program. The Company has no generating plants under construction. Construction of new transmission and distribution facilities and capital improvements, including those needed to meet environmental standards for existing generation, transmission, and distribution facilities, will continue.

Long-Term Service Agreements

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

In general, these LTSAs are in effect through two major inspection cycles per unit. Scheduled payments to GE, which are subject to price escalation, are made at various intervals based on actual operating hours of the respective units. Total remaining payments to GE under these agreements for facilities owned are currently estimated at $256 million over the remaining life of the agreements, which are currently estimated to range up to 10 years. However, the LTSAs contain various cancellation provisions at the option of the Company. Payments made to GE prior to the performance of any planned maintenance are recorded as either prepayments or other deferred charges and assets in the balance sheets. Inspection costs are capitalized or charged to expense based on the nature of the work performed.

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 2.9 million tons, equating to approximately $127 million, through 2019. Estimated expenditures (based on minimum contracted obligated dollars) over the next five years are $11 million in 2010, $15 million in 2011, $15 million in 2012, $16 million in 2013, and $16 million in 2014.

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 and nitrogen oxide 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, 2009. Total estimated minimum long-term commitments at December 31, 2009 were as follows:

	Commitments		
	Natural Gas	Coal	Nuclear Fuel
		(in millions)	
2010	$ 413	$1,420	$ 73
2011	275	894	48
2012	176	695	51
2013	141	516	37
2014	113	407	23
2015 and thereafter	148	975	90
Total commitments	$1,266	$4,907	$322

Additional commitments for fuel will be required to supply the Company's future needs. Total charges for nuclear fuel included in fuel expense totaled $78 million in 2009, $70 million in 2008, and $65 million in 2007.

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 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 entered into various long-term commitments for the purchase of capacity and energy. Total estimated minimum long-term obligations at December 31, 2009 were as follows:

	Commitments		
	Affiliated	Non-Affiliated	Total
		(in millions)	
2010	$13	$ 26	$ 39
2011	-	30	30
2012	-	30	30
2013	-	31	31
2014	-	36	36
2015 and thereafter	-	337	337
Total commitments	$13	$490	$503

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

Operating Leases

The Company has entered into rental agreements for coal rail cars, vehicles, and other equipment with various terms and expiration dates. These expenses totaled $26.9 million in 2009, $26.1 million in 2008, and $27.7 million in 2007. Of these amounts, $20.3 million, $19.2 million, and $20.5 million for 2009, 2008, and 2007, respectively, relate to the rail car leases and are recoverable through the Company's Rate ECR. At December 31, 2009, estimated minimum rental commitments for non-cancelable operating leases were as follows:

	Minimum Lease Payments		
	Rail Cars	Vehicles & Other	Total
		(in millions)	
2010	$16	$ 6	$22
2011	7	4	11
2012	7	3	10
2013	4	1	5
2014	3	-	3
2015 and thereafter	10	-	10
Total *	$47	$14	$61

* Total does not include payments related to a non-affiliated PPA that is accounted for as an operating lease. Obligations related to this agreement are included in the above purchased power commitments table.

In addition to the rental commitments above, the Company has potential obligations upon expiration of certain leases with respect to the residual value of the leased property. These leases expire in 2010 and 2013, and the Company's maximum obligations are $61.2 million and $18.6 million, respectively. At the termination of the leases, at the Company's option, the Company may negotiate an extension, exercise its purchase option, or the property can be sold to a third party. The Company expects that the fair market value of the leased property would substantially eliminate the Company's payments under the residual value obligations. However, due to the recessionary economy, it is possible that the fair market value of the leased property would not eliminate the Company's payments under the residual value obligations on the leases expiring in 2010.

Guarantees

At December 31, 2009, the Company had outstanding guarantees related to SEGCO's purchase of certain pollution control facilities and issuance of senior notes, as discussed in Note 4, and to certain residual values of leased assets as described above in "Operating Leases."

8. STOCK OPTION PLAN

Southern Company provides non-qualified stock options to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2009, there were 1,412 current and former employees of the Company participating in the stock option plan and there were 21 million shares of Southern Company common stock remaining available for awards under this plan. The prices of options granted to date have been at the fair market value of the shares on the dates of grant. Options granted to date become exercisable pro rata over a maximum period of three years from the date of grant. 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 2009, 2008, and 2007 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. The 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	**2009**	2008	2007
Expected volatility	**15.6%**	13.1%	14.8%
Expected term *(in years)*	**5.0**	5.0	5.0
Interest rate	**1.9%**	2.8%	4.6%
Dividend yield	**5.4%**	4.5%	4.3%
Weighted average grant-date fair value	**$1.80**	$2.37	$4.12

The Company's activity in the stock option plan for 2009 is summarized below:

	Shares Subject to Option	**Weighted Average Exercise Price**
Outstanding at December 31, 2008	6,809,196	$31.61
Granted	2,084,772	31.39
Exercised	(137,082)	19.79
Cancelled	(7,412)	29.40
Outstanding at December 31, 2009	**8,749,474**	**$31.74**
Exercisable at December 31, 2009	**5,791,523**	**$31.10**

The number of stock options vested and expected to vest in the future, as of December 31, 2009 was not significantly different from the number of stock options outstanding at December 31, 2009 as stated above. As of December 31, 2009, the weighted average remaining contractual term for the options outstanding and options exercisable was 6.0 years and 4.6 years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $20.8 million and $17.1 million, respectively.

As of December 31, 2009, there was $1.0 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 11 months.

For the years ended December 31, 2009, 2008, and 2007, total compensation cost for stock option awards recognized in income was $3.8 million, $3.1 million, and $4.9 million, respectively, with the related tax benefit also recognized in income of $1.4 million, $1.2 million, and $1.9 million, respectively.

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 total intrinsic value of options exercised during the years ended December 31, 2009, 2008, and 2007 was $1.7 million, $5.2 million, and $9.7 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $0.7 million, $2.0 million, and $3.7 million, respectively, for the years ended December 31, 2009, 2008, and 2007.

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 Plant Farley. The Act provides funds up to $12.6 billion for public liability claims that could arise from a single nuclear incident. Plant Farley 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 is $235 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' 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. In the event of a loss, the amount of insurance available may not be adequate to cover property damage and other incurred expenses.

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 and has elected a 12-week deductible waiting period.

Under each of the NEIL policies, members are subject to assessments if losses each year exceed the accumulated funds available to the insurer under that policy. The current maximum annual assessments for the Company under the NEIL policies would be $38 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 bond trustees as may be appropriate under the policies and applicable trust indentures.

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

10. 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, 2009, 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, are as follows:

	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:				
Energy-related derivatives	$ -	$ 1	$ -	$ 1
Nuclear decommissioning trusts:[a]				
Domestic equity	296	49	-	345
U.S. Treasury and government agency securities	11	5	-	16
Corporate bonds	-	76	-	76
Mortgage and asset backed securities	-	42	-	42
Other	-	9	-	9
Cash equivalents and restricted cash	346	-	-	346
Total	$653	$182	$ -	$835
Liabilities:				
Energy-related derivatives	$ -	$ 45	$ -	$ 45
Interest rate derivatives	-	4	-	4
Total	$ -	$ 49	$ -	$ 49

(a) Excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases.

Energy-related derivatives and interest rate derivatives primarily consist of over-the-counter contracts. See Note 11 herein for additional information. The nuclear decommissioning trust funds are invested in a diversified mix of equity and fixed income securities. See Note 1 under "Nuclear Decommissioning" for additional information. The cash equivalents and restricted cash consist of securities with original maturities of 90 days or less. All of these financial instruments and investments are valued primarily using the market approach.

As of December 31, 2009, 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, are as follows:

As of December 31, 2009:	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
	(in millions)			
Nuclear decommissioning trusts:				
Trust owned life insurance	$ 78	None	Daily	15 days
Cash equivalents and restricted cash:				
Money market funds	346	None	Daily	Not applicable

The nuclear decommissioning trust includes investments in Trust-Owned Life Insurance (TOLI). The taxable nuclear decommissioning trust invests in the TOLI in order to minimize the impact of taxes on the portfolio and can draw on the value of the TOLI via death proceeds, loans against the cash surrender value, and/or the cash surrender value, subject to legal restrictions. The amounts reported in the tables above reflect the fair value of investments the insurer has made in relation to the TOLI agreements. The nuclear decommissioning trust does not own the underlying investments, but the fair value of the investments approximates the cash surrender value of the TOLI policies. The investments made by the insurer are in commingled funds. The commingled funds primarily include investments in domestic and international equity securities and predominantly high-quality fixed income securities. These fixed income securities include U.S. Treasury and government agency fixed income securities, non-U.S. government and agency fixed income securities, domestic and foreign corporate fixed income securities, and, to some degree, mortgage and asset backed securities. The passively managed funds seek to replicate the performance of a related index. The actively managed funds seek to exceed the performance of a related index through security analysis and selection.

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the Securities and Exchange Commission and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis, up to the full amount of the Company's investment in the money market funds.

As of December 31, 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:		
2009	**$6,182**	**$6,357**
2008	5,855	5,784

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, 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 Alabama PSC, through the use of financial derivative contracts.

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. 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 three 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 clause.
- *Cash Flow Hedges* – Gains and losses on energy-related derivatives designated as cash flow hedges are used to hedge anticipated purchases and sales and are initially deferred in other comprehensive income (OCI) before being recognized in income in the same period as the hedged transactions are reflected in earnings.
- *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, 2009, the net volume of energy-related derivative contracts for natural gas positions for the Company, together with the longest hedge date over which it is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest date for derivatives not designated as hedges, were as follows:

Net Purchased mmBtu* *(in millions)*	Longest Hedge Date	Longest Non-Hedge Date
37	2014	-

*mmBtu – million British thermal units

For cash flow hedges, the amounts expected to be reclassified from OCI to revenue and fuel expense for the next 12-month period ending December 31, 2010 are immaterial.

Interest Rate Derivatives

The Company also enters into interest rate derivatives, which include forward-starting interest rate swaps, 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. The derivatives employed as hedging instruments are structured to minimize ineffectiveness.

For cash flow hedges, the fair value gains or losses are recorded in OCI and are reclassified into earnings at the same time the hedged transactions affect earnings.

At December 31, 2009, the Company had outstanding interest rate derivatives designated as cash flow hedges of existing debt as follows:

Notional Amount	Variable Rate Received	Weighted Average Fixed Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2009
(in millions)				*(in millions)*
$576	SIFMA Index*	2.69%	February 2010	$(4)

* Securities Industry and Financial Markets Association Municipal Swap Index (SIFMA)

The estimated pre-tax loss that will be reclassified from OCI to interest expense for the next 12-month period ending December 31, 2010 is $1.0 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2035.

Derivative Financial Statement Presentation and Amounts

At December 31, 2009 and 2008, 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**	**2009**	**2008**	**Balance Sheet Location**	**2009**	**2008**
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$1**	$4	Liabilities from risk management activities	**$34**	$ 75
	Other deferred charges and assets	**-**	-	Other deferred credits and liabilities	**11**	21
Total derivatives designated as hedging instruments for regulatory purposes		**$1**	$4		**$45**	$ 96
Derivatives designated as hedging instruments in cash flow hedges						
Interest rate derivatives:	Other current assets	**-**	-	Liabilities from risk management activities	**4**	9
	Other deferred charges and assets	**-**	-	Other deferred credits and liabilities	**-**	2
Total derivatives designated as hedging instruments in cash flow hedges		**$-**	$-		**$ 4**	$ 11
Total		**$1**	$4		**$49**	$107

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

At December 31, 2009 and 2008, 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 were as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2009**	**2008**	**Balance Sheet Location**	**2009**	**2008**
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$(34)**	$(75)	Other regulatory liabilities, current	**$1**	$4
	Other regulatory assets, deferred	**(11)**	(21)	Other regulatory liabilities, deferred	**-**	-
Total energy-related derivative gains (losses)		**$(45)**	$(96)		**$1**	$4

For the years ended December 31, 2009, 2008, and 2007, the pre-tax effect of interest rate derivatives designated as cash flow hedging instruments on the statements of income were 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	2009	2008	2007	Statements of Income Location	2009	2008	2007
		(in millions)				(in millions)	
Interest rate derivatives	**$(5)**	$(11)	$(3)	Interest expense	**$(12)**	$(3)	$(1)

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

For the years ended December 31, 2009, 2008, and 2007, the pre-tax effect of energy-related derivatives not designated as hedging instruments were immaterial.

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. There are 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, 2009, the fair value of derivative liabilities with contingent features was $7.6 million.

At December 31, 2009, 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 $33.3 million.

Currently, the Company has investment grade credit ratings from the major rating agencies with respect to debt, preferred securities, preferred stock, and/or preference stock.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. The Company participated 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 2009 and 2008 are as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
		(in millions)	
March 2009	**$1,340**	**$299**	**$146**
June 2009	**1,366**	**349**	**177**
September 2009	**1,592**	**483**	**261**
December 2009	**1,231**	**189**	**86**
March 2008	$1,337	$274	$130
June 2008	1,470	319	153
September 2008	1,865	478	252
December 2008	1,405	198	81

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

SELECTED FINANCIAL AND OPERATING DATA 2005-2009
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	2009	2008	2007	2006	2005
Operating Revenues (in thousands)	**$5,528,574**	$6,076,931	$5,359,993	$5,014,728	$4,647,824
Net Income after Dividends					
on Preferred and Preference Stock (in thousands)	**$669,536**	$615,959	$579,582	$517,730	$507,895
Cash Dividends					
on Common Stock (in thousands)	**$522,800**	$491,300	$465,000	$440,600	$409,900
Return on Average Common Equity (percent)	**13.27**	13.30	13.73	13.23	13.72
Total Assets (in thousands)	**$17,524,093**	$16,536,006	$15,746,625	$14,655,290	$13,689,907
Gross Property Additions (in thousands)	**$1,322,596**	$1,532,673	$1,203,300	$960,759	$890,062
Capitalization (in thousands):					
Common stock equity	**$5,236,461**	$4,854,310	$4,410,683	$4,032,287	$3,792,726
Preference stock	**343,373**	343,412	343,466	147,361	-
Redeemable preferred stock	**341,715**	341,715	340,046	465,046	465,046
Long-term debt	**6,082,489**	5,604,791	4,750,196	4,148,185	3,869,465
Total (excluding amounts due within one year)	**$12,004,038**	$11,144,228	$9,844,391	$8,792,879	$8,127,237
Capitalization Ratios (percent):					
Common stock equity	**43.6**	43.6	44.8	45.9	46.7
Preference stock	**2.9**	3.1	3.5	1.7	-
Redeemable preferred stock	**2.8**	3.0	3.4	5.3	5.7
Long-term debt	**50.7**	50.3	48.3	47.1	47.6
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Security Ratings:					
First Mortgage Bonds -					
Moody's	**-**	-	-	-	A1
Standard and Poor's	**-**	-	-	-	A+
Fitch	**-**	-	-	-	AA-
Preferred Stock/ Preference Stock -					
Moody's	**Baa1**	Baa1	Baa1	Baa1	Baa1
Standard and Poor's	**BBB+**	BBB+	BBB+	BBB+	BBB+
Fitch	**A**	A	A	A	A
Unsecured Long-Term Debt -					
Moody's	**A2**	A2	A2	A2	A2
Standard and Poor's	**A**	A	A	A	A
Fitch	**A+**	A+	A+	A+	A+
Customers (year-end):					
Residential	**1,229,134**	1,220,046	1,207,883	1,194,696	1,184,406
Commercial	**198,642**	211,119	216,830	214,723	212,546
Industrial	**5,912**	5,906	5,849	5,750	5,492
Other	**780**	775	772	766	759
Total	**1,434,468**	1,437,846	1,431,334	1,415,935	1,403,203
Employees (year-end)	**6,842**	6,997	6,980	6,796	6,621

	2009	2008	2007	2006	2005
Operating Revenues (in thousands):					
Residential	**$1,961,678**	$1,997,603	$1,833,563	$1,664,304	$1,476,211
Commercial	**1,429,601**	1,459,466	1,313,642	1,172,436	1,062,341
Industrial	**1,080,208**	1,381,100	1,238,368	1,140,225	1,065,124
Other	**25,594**	24,112	21,383	18,766	17,745
Total retail	**4,497,081**	4,862,281	4,406,956	3,995,731	3,621,421
Wholesale - non-affiliates	**619,859**	711,903	627,047	634,552	551,408
Wholesale - affiliates	**236,995**	308,482	144,089	216,028	288,956
Total revenues from sales of electricity	**5,353,935**	5,882,666	5,178,092	4,846,311	4,461,785
Other revenues	**174,639**	194,265	181,901	168,417	186,039
Total	**5,528,574**	$6,076,931	$5,359,993	$5,014,728	$4,647,824
Kilowatt-Hour Sales (in thousands):					
Residential	**18,071,471**	18,379,801	18,874,039	18,632,935	18,073,783
Commercial	**14,185,622**	14,551,495	14,761,243	14,355,091	14,061,650
Industrial	**18,555,377**	22,074,616	22,805,676	23,187,328	23,349,769
Other	**217,594**	201,283	200,874	199,445	198,715
Total retail	**51,030,064**	55,207,195	56,641,832	56,374,799	55,683,917
Wholesale - non-affiliates	**14,316,742**	15,203,960	15,769,485	15,978,465	15,442,728
Wholesale - affiliates	**6,473,084**	5,256,130	3,241,168	5,145,107	5,735,429
Total	**71,819,890**	75,667,285	75,652,485	77,498,371	76,862,074
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**10.86**	10.87	9.71	8.93	8.17
Commercial	**10.08**	10.03	8.90	8.17	7.55
Industrial	**5.82**	6.26	5.43	4.92	4.56
Total retail	**8.81**	8.81	7.78	7.09	6.50
Wholesale	**4.12**	4.99	4.06	4.03	3.97
Total sales	**7.45**	7.77	6.84	6.25	5.80
Residential Average Annual Kilowatt-Hour Use Per Customer	**14,716**	15,162	15,696	15,663	15,347
Residential Average Annual Revenue Per Customer	**$1,597**	$1,648	$1,525	$1,399	$1,253
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**12,222**	12,222	12,222	12,222	12,216
Maximum Peak-Hour Demand (megawatts):					
Winter	**10,701**	10,747	10,144	10,309	9,812
Summer	**10,870**	11,518	12,211	11,744	11,162
Annual Load Factor (percent)	**59.8**	60.9	59.4	61.8	63.2
Plant Availability (percent):					
Fossil-steam	**88.5**	90.1	88.2	89.6	90.5
Nuclear	**93.3**	94.1	87.5	93.3	92.9
Source of Energy Supply (percent):					
Coal	**53.4**	58.5	60.9	60.2	59.5
Nuclear	**18.6**	17.8	16.5	17.4	17.2
Hydro	**7.9**	2.9	1.8	3.8	5.6
Gas	**11.8**	9.2	8.7	7.6	6.8
Purchased power -					
From non-affiliates	**2.0**	2.9	1.8	2.1	3.8
From affiliates	**6.3**	8.7	10.3	8.9	7.1
Total	**100.0**	100.0	100.0	100.0	100.0

DIRECTORS AND OFFICERS
Alabama Power Company 2009 Annual Report

Directors

Whit Armstrong
President, Chairman, and CEO,
The Citizens Bank

Ralph D. Cook
Attorney, Hare, Wynn, Newell & Newton

David J. Cooper, Sr.
Vice Chairman,
Cooper/T. Smith Corporation

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

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

James K. Lowder
Chairman,
The Colonial Company

Charles D. McCrary
President and CEO,
Alabama Power Company

Malcolm Portera
Chancellor, The University of Alabama System

Robert D. Powers
President,
The Eufaula Agency, Inc.

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

C. Dowd Ritter
Chairman and CEO,
Regions Financial Corporation

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

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

James W. Wright
Chairman,
First Tuskegee Bank

Officers

Charles D. McCrary
President and Chief Executive Officer

Art P. Beattie
Executive Vice President, Chief Financial Officer, and Treasurer

Mark A. Crosswhite
Executive Vice President

Steve R. Spencer
Executive Vice President

Gordon G. Martin
Senior Vice President and General Counsel

Robert Holmes, Jr.
Senior Vice President

Robin A. Hurst [1]
Senior Vice President

Michael L. Scott [2]
Senior Vice President

Jerry L. Stewart
Senior Vice President

Moses H. Feagin
Vice President and Comptroller

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

Kathleen S. King
Vice President, Chief Information Officer

Greg Barker
Vice President

Matthew W. Bowden
Vice President

Willard L. Bowers [3]
Vice President

Kenneth E. Coleman
Vice President, Southern Division

Daniel K. Glover [4]
Vice President

Larry R. Grill [5]
Vice President

Gerald L. Johnson [6]
Vice President,
Birmingham Division

Marsha S. Johnson
Vice President

William B. Johnson
Vice President

Bobby J. Kerley [7]
Vice President

Barbara J. Knight [8]
Vice President,
Birmingham Division

Richard J. Mandes, Jr. [9]
Vice President

Leigh Davis-Perry
Vice President

Myrna J. Pittman
Vice President

Leslie D. Sanders
Vice President

R. Michael Saxon [10]
Vice President, Mobile Division

Julia H. Segars
Vice President, Eastern Division

Nicholas C. Sellers
Vice President

Zeke W. Smith
Vice President

Cheryl A. Thompson [11]
Vice President, Mobile Division

Terry H. Waters [12]
Vice President, Marketing

Anita Allcorn-Walker
Assistant Comptroller

Ronald Q. Patterson
Assistant Comptroller

E. Wayne Boston [13]
Assistant Secretary and Assistant Treasurer

Melissa K. Caen [14]
Assistant Secretary and Assistant Treasurer

Ceila H. Shorts
Assistant Secretary

Kay I. Worley
Assistant Secretary

J. Randy DeRieux
Assistant Treasurer

[1] **Retired 5/09**
[2] **Retired 4/09**
[3] **Retired 7/09**
[4] **Elected 4/09**
[5] **Retired 4/09**
[6] **Resigned 1/10**
[7] **Retires 4/10**
[8] **Effective 3/10**
[9] **Elected 1/10**
[10] **Effective 4/10**
[11] **Retires 4/10**
[12] **Effective 3/10**
[13] **Resigned 8/09**
[14] **Elected 8/09**

CORPORATE INFORMATION
Alabama Power Company 2009 Annual Report

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

Profile
The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Alabama and to wholesale customers in the Southeast. The Company sells electricity to more than 1.4 million customers within its service area of approximately 45,000 square miles. In 2009, retail energy sales accounted for 71 percent of the Company's total sales of 72 billion kilowatt-hours.

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

Trustee, Registrar and Interest Paying Agent
All series of Senior Notes and
Trust Preferred Securities
The Bank of New York Mellon
Global Corporate Trust
505 North 20th Street, Suite 950
Birmingham, AL 35203

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

The 5.30% Series Class A Preferred Stock
The Bank of New York Mellon
Shareowner Services
480 Washington Boulevard
Jersey City, NJ 07310-1900

Number of Preferred Shareholders of record as of December 31, 2009, was 1,462.

Form 10-K
A copy of the Form 10-K as filed with the Securities and Exchange Commission will be provided upon written request to the office of the Corporate Secretary. For additional information, contact the office of the Corporate Secretary at (205) 257-3385.

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

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