ALABAMA POWER COMPANY

2010 Annual Report

ALABAMA POWER

A SOUTHERN COMPANY

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Alabama Power Company 2010 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, 2010.

Charles D. McCrary
President and Chief Executive Officer

Philip C. Raymond
Executive Vice President, Chief Financial Officer, and Treasurer

February 25, 2011

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, 2010 and 2009, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2010. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements based on our audits.

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

In our opinion, such financial statements (pages 28 to 72) present fairly, in all material respects, the financial position of Alabama Power Company at December 31, 2010 and 2009, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

Deloitte + Touche LLP

Birmingham, Alabama
February 25, 2011

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 business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales given economic conditions, and to effectively manage and secure timely recovery of 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 required costs and capital expenditures 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 more than 1.4 million customers, the Company continues to focus on several key indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income after dividends on preferred and preference stock. The Company's financial success is directly tied to the satisfaction of its customers. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The fossil/hydro 2010 Peak Season EFOR 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 2010 was better than the target for these reliability measures.

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

Key Performance Indicator	2010 Target Performance	2010 Actual Performance
Customer Satisfaction	Top quartile in customer surveys	Top quartile
Peak Season EFOR – fossil/hydro	5.06% or less	1.22%
Net Income After Dividends on Preferred and Preference Stock	$696 million	$707 million

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

Earnings

The Company's 2010 net income after dividends on preferred and preference stock of $707 million increased $37 million (5.5%) over the prior year. The increase was primarily due to increases in rates under the rate stabilization and equalization plan (Rate RSE) and the rate certificated new plant environmental (Rate CNP Environmental) that took effect January 2010, colder weather in the first and fourth quarters 2010, and warmer weather in the second and third quarters 2010. The increases in retail revenues were partially offset by increases in operations and maintenance expenses, increases in depreciation and amortization, and reductions in wholesale revenues from sales to non-affiliates and allowance for funds used during construction (AFUDC) equity.

The Company's net income after dividends on preferred and preference stock of $670 million in 2009 increased $54 million (8.8%) 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 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 (6.2%) 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 RSE and the Rate CNP Environmental that took effect January 1, 2008, partially offset by higher non-fuel operating expenses and depreciation.

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

	Amount	Increase (Decrease) from Prior Year		
	2010	**2010**	2009	2008
		(in millions)		
Operating revenues	**$5,976**	**$447**	$(548)	$717
Fuel	**1,851**	**27**	(360)	422
Purchased power	**280**	**(27)**	(231)	100
Other operations and maintenance	**1,418**	**207**	(48)	73
Depreciation and amortization	**606**	**61**	25	48
Taxes other than income taxes	**332**	**10**	15	20
Total operating expenses	**4,487**	**278**	(599)	663
Operating income	**1,489**	**169**	51	54
Total other income and (expense)	**(280)**	**(53)**	19	2
Income taxes	**463**	**79**	16	17
Net income	**746**	**37**	54	39
Dividends on preferred and preference stock	**39**	**-**	-	3
Net income after dividends on preferred and preference stock	**$ 707**	**$ 37**	$ 54	$ 36

Operating Revenues

Operating revenues for 2010 were $6.0 billion, reflecting a $447 million increase from 2009. The following table summarizes the principal factors that have affected operating revenues for the past three years:

	Amount		
	2010	2009	2008
		(in millions)	
Retail – prior year	**$4,497**	$4,862	$4,407
Estimated change in –			
Rates and pricing	**310**	174	246
Sales growth (decline)	**(11)**	(109)	26
Weather	**199**	(12)	(70)
Fuel and other cost recovery	**81**	(418)	253
Retail – current year	**5,076**	4,497	4,862
Wholesale revenues –			
Non-affiliates	**465**	620	712
Affiliates	**236**	237	308
Total wholesale revenues	**701**	857	1,020
Other operating revenues	**199**	175	195
Total operating revenues	**$5,976**	$5,529	$6,077
Percent change	**8.1%**	(9.0)%	13.4%

Retail revenues in 2010 were $5.1 billion. These revenues increased $579 million (12.9%) in 2010, decreased $365 million (7.5%) in 2009, and increased $455 million (10.3%) in 2008. The increase in 2010 was due to increases in rates and pricing under Rate RSE and Rate CNP Environmental that took effect January 2010, colder weather in the first and fourth quarters 2010, and warmer weather in the second and third quarters 2010. 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 increase in 2008 was primarily due to an increase in fuel revenue and a base rate increase of 5.6%. 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:

	2010	2009	2008
		(in millions)	
Unit power sales –			
Capacity	**$ 84**	$158	$160
Energy	**95**	207	238
Total	**179**	365	398
Other power sales –			
Capacity and other	**148**	133	134
Energy	**138**	122	180
Total	**286**	255	314
Total non-affiliated	**$465**	$620	$712

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.

In 2010, wholesale revenues from sales to non-affiliates decreased $155 million (25.0%), primarily due to a 39.5% decrease in KWH sales. In May 2010, the long-term unit power sales contracts expired and the unit power sales capacity revenues ceased. Beginning in June 2010, such capacity, which was subject to the unit power sales contracts, became available for retail service. The changes in wholesale revenues from sales to non-affiliates in 2009 and 2008 were not material. 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). These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost and energy purchases are generally offset by energy revenues through the Company's energy cost recovery clauses. The change in wholesale revenues from sales to affiliates for 2010 was not material. In 2009, wholesale revenues from sales to affiliates decreased $71 million (23.1%) 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 million (113.9%) 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.

Other operating revenues increased $24 million (13.7%) in 2010 due to a $13 million increase in transmission sales and a $12 million increase in revenues from gas-fueled co-generation steam facilities as a result of greater sales volume. Other operating revenues in 2009 decreased $20 million (10.3%) from 2008 primarily due to a $43 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 million in customer charges related to late fees. In 2008, other operating revenues increased $13 million (7.1%) from 2007 primarily due to a $12 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 2010 and the percent change by year were as follows:

	Total KWHs	Total KWH Percent Change			Weather-Adjusted Percent Change		
	2010	**2010**	2009	2008	**2010**	2009	2008
	(in billions)						
Residential	**20.4**	**13.0%**	(1.7)%	(2.6)%	**(0.6)%**	(1.0)%	2.2%
Commercial	**14.7**	**3.8**	(2.5)	(1.4)	**(1.1)**	(2.1)	1.0
Industrial	**20.7**	**11.1**	(15.9)	(3.2)	**11.1**	(15.9)	(3.2)
Other	**0.2**	**(0.8)**	8.1	0.2	**(0.8)**	8.1	0.2
Total retail	**56.0**	**9.7**	(7.6)	(2.5)	**3.5%**	(7.2)%	(0.3)%
Wholesale -							
Non-affiliates	**8.6**	**(39.5)**	(5.8)	(3.6)			
Affiliates	**6.1**	**(6.2)**	23.2	62.2			
Total wholesale	**14.7**	**(29.2)**	1.6	7.6			
Total energy sales	**70.7**	**(1.6)%**	(5.1)%	- %			

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 2010 were 9.7% greater than in 2009. Energy sales were up in 2010 across major classes of customers. Residential and commercial sales increased 13.0% and 3.8%, respectively, due primarily to significant weather-driven increases in KWH sales as a result of colder weather in the first and fourth quarters 2010 and warmer weather in the second and third quarters 2010. Industrial sales increased 11.1% in 2010 as a result of increased customer demand in most major sectors, including primary metals, chemicals, transportation, and textiles sectors, due to a recovering economy.

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 2008.

See "Operating Revenues" above for a discussion of significant changes in wholesale revenues from sales to non-affiliates and wholesale revenues from sales to affiliated companies as related to changes in price and KWH sales.

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.

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.

Details of the Company's electricity generated and purchased were as follows:

	2010	2009	2008
Total generation *(billions of KWHs)*	**69.2**	68.8	70.0
Total purchased power *(billions of KWHs)*	**5.0**	6.3	9.2
Sources of generation *(percent)* –			
Coal	**61**	58	66
Nuclear	**19**	20	20
Gas	**15**	13	11
Hydro	**5**	9	3
Cost of fuel, generated *(cents per net KWH)* –			
Coal	**3.02**	3.02	2.94
Nuclear	**0.60**	0.56	0.50
Gas	**4.47**	5.24	8.30
Average cost of fuel, generated *(cents per net KWH)**	**2.76**	2.79	3.00
Average cost of purchased power *(cents per net KWH)*	**6.42**	6.05	7.44

*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. KWHs generated by hydro are excluded from the average cost of fuel, generated.

Fuel and purchased power expenses were $2.1 billion in 2010. The increase over the prior year costs was not material.

Fuel and purchased power expenses were $2.1 billion in 2009, a decrease of $591 million (21.7%) below the prior year costs. This decrease was the result of a $367 million decrease related to the volume of KWHs generated and purchased and a $225 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 $522 million (23.7%) above the prior year costs. This increase was the result of a $561 million increase in the cost of fuel, offset by a $39 million decrease 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 2010, purchased power from non-affiliates decreased $16 million (18.2%) due to a 22.4% decrease in the amount of energy purchased, partially offset by a 6.7% increase in the average cost per KWH. In 2009, purchased power from non-affiliates decreased $91 million (50.8%) 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 million (39.0%) due to a 31.4% decrease in the amount of energy purchased. In 2008, the average cost of purchased power from non-affiliates increased $82 million (84.5%) due to a 67.9% increase in the amount of energy purchased.

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

Other Operations and Maintenance Expenses

In 2010, other operations and maintenance expenses increased $207 million (17.1%) due to a $60 million increase in steam production expenses related to planned outage maintenance, environmental mandates (which are offset by revenues associated with Rate CNP Environmental) and maintenance costs related to increases in labor and materials expenses, a $59 million increase in administrative and general expenses related to affiliated service companies' expenses, injuries and damages reserve, labor, and other general expenses, partially offset by a reduction in employee medical and other benefit-related expenses, a $57 million increase in transmission and distribution expenses related to line clearing costs and an additional accrual to the natural disaster reserve (NDR), and a $21 million increase in nuclear production expense related to scheduled outage costs and maintenance costs related to increases in labor.

In 2009, other operations and maintenance expenses decreased $48 million (3.8%) primarily due to a $39 million decrease in transmission and distribution expenses related to a reduction in overhead line clearing and labor which was offset by a $40 million additional NDR accrual, an $18 million decrease in steam production expense related to fewer scheduled outages, a $13 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 $6 million decrease in customer accounts expense, and a $5 million decrease in customer service and information expense.

In 2008, other operations and maintenance expenses increased $73 million (6.2%) primarily due to a $27 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 $23 million increase in nuclear production expense related to operations and scheduled outage costs, and a $20 million increase in transmission and distribution expense related to overhead line clearing costs.

See FUTURE EARNINGS POTENTIAL – "PSC Matters – Natural Disaster Reserve" herein for additional information.

Depreciation and Amortization

Depreciation and amortization increased $61 million (11.2%) in 2010, $25 million (4.8%) in 2009, and $48 million (10.2%) in 2008, 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.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $10 million (3.1%) in 2010, $15 million (4.9%) in 2009, and $20 million (7.0%) in 2008. The increase in 2010 was primarily due to increases in state and municipal public utility license tax bases and an increase in payroll taxes. The increases in 2009 and 2008 were primarily due to increases in state and municipal public utility license tax bases.

Allowance for Funds Used During Construction Equity

AFUDC equity decreased $43 million (54.4%) in 2010 from 2009 primarily due to the completion of construction projects related to environmental mandates at steam generating facilities, partially offset by an increase in nuclear production projects. AFUDC equity increased $33 million (71.7%) in 2009 and $11 million (31.4%) in 2008 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 $5 million (1.7%) in 2010. The increase in 2010 was not material. Interest expense, net of amounts capitalized increased $20 million (6.9%) 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 million (1.9%) in 2008 which was not material when compared to the prior year.

Income Taxes

Income taxes increased $79 million (20.6%) in 2010, primarily due to higher pre-tax income as compared to 2009, an increase in Alabama state taxes due to a decrease in the state deduction for federal income taxes paid, and an increase in the tax expense associated with a decrease in AFUDC equity and a decrease in the Internal Revenue Code of 1986, as amended (Internal Revenue Code), Section 199 production activities deduction.

Income taxes increased $16 million (4.3%) in 2009, primarily due to higher pre-tax income as compared to 2008, 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 Internal Revenue Code, Section 199 production activities deduction.

Income taxes increased $17 million (4.8%) in 2008, primarily due to higher pre-tax income as compared to 2007, partially offset by the tax benefit associated with an increase in AFUDC equity and a decrease in expense related to normal tax contingencies.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years. 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" and "FERC Matters" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.

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

Environmental Matters

Compliance costs related to the Clean Air Act and other environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may exceed amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. 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. The separate action against the Company is ongoing.

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. On September 2, 2010, the EPA dismissed five of its eight remaining claims against the Company, leaving only three claims for summary disposition or trial, including the claim relating to a facility co-owned by Mississippi Power. The parties each filed motions for summary judgment on September 30, 2010. The court has set a trial date for October 2011 for any remaining claims.

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures or affect the timing of currently budgeted capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

Carbon Dioxide Litigation

New York Case

In July 2004, three environmental groups and attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed complaints in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. The complaints allege that the companies' emissions of carbon dioxide, a greenhouse gas, contribute to global warming, which the plaintiffs assert is a public nuisance. Under common law public and private nuisance theories, the plaintiffs seek a judicial order (1) holding each defendant jointly and severally liable for creating, contributing to, and/or maintaining global warming and (2) requiring each of the defendants to cap its emissions of carbon dioxide and then reduce those emissions by a specified percentage each year for at least a decade. The plaintiffs have not, however, requested that damages be awarded in connection with their claims. Southern Company believes these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2005, the U.S. District Court for the Southern District of New York granted Southern Company's and the other defendants' motions to dismiss these cases. The plaintiffs filed an appeal to the U.S. Court of Appeals for the Second Circuit in October 2005 and, in September 2009, the U.S. Court of Appeals for the Second Circuit reversed the district court's ruling, vacating the dismissal of the plaintiffs' claim, and remanding the case to the district court. On December 6, 2010, the U.S. Supreme Court granted the defendants' petition for writ of certiorari. The ultimate outcome of these matters cannot be determined at this time.

Kivalina Case

In February 2008, the Native Village of Kivalina and the City of Kivalina filed a suit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs are the governing bodies of an Inupiat village in Alaska. The plaintiffs contend that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants have acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. Southern Company believes that these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case based on lack of jurisdiction and ruled the claims were barred by the political question doctrine and by the plaintiffs' failure to establish the standard for determining that the defendants' conduct caused the injury alleged. In November 2009, the plaintiffs filed an appeal with the U.S. Court of Appeals for the Ninth Circuit challenging the district court's order dismissing the case. On January 24, 2011, the defendants filed a motion with the U.S.

Court of Appeals for the Ninth Circuit to defer scheduling the case pending the decision of the U.S. Supreme Court in the New York case discussed above. The ultimate outcome of this matter cannot be determined at this time.

Other Litigation

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

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2010, the Company had invested approximately $3.0 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of $130 million, $526 million, and $617 million for 2010, 2009, and 2008, respectively. The Company expects that capital expenditures to comply with existing statutes and regulations will be $47 million, $26 million, and $53 million for 2011, 2012, and 2013, respectively. These environmental costs that are known and estimable at this time are included in the Company's approved construction program and capital expenditures under the heading "Capital" in the table FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein. In addition, the Company currently estimates additional environmental expenditures may be required to comply with anticipated new statutes and regulations. Such additional environmental expenditures are estimated to be in amounts up to $48 million, $108 million, and $354 million for 2011, 2012, and 2013, respectively. The Company's compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of any new or revised environmental statutes and regulations that are enacted, including the proposed environmental legislation and regulations described below; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix.

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

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Through 2010, the Company had spent approximately $2.6 billion in reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions and in monitoring emissions pursuant to the Clean Air Act. As a result, emissions control projects have been completed recently or are underway. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone air quality standard. No area within the Company's service area is currently designated as nonattainment for the standard. In March 2008, the EPA issued a final rule establishing a more stringent eight-hour ozone standard, and on January 6, 2010, the EPA proposed further reductions in the level of the standard. Under the EPA's current schedule, a final revision to the eight-hour ozone standard is expected in July 2011, with state implementation plans for any resulting nonattainment areas due in mid-2014. The revised eight-hour ozone standard is expected to result in designation of nonattainment areas within the Company's service territory and could result in additional required reductions in NO_x emissions.

During 2005, the EPA's annual fine particulate matter nonattainment designations became effective for one area within the Company's service area. State implementation plans demonstrating attainment with the annual standard for all areas have been submitted to the EPA. In September 2006, the EPA published a final rule which increased the stringency of the 24-hour average fine particulate matter air quality standard. In October 2009, the EPA designated the Birmingham area as nonattainment for the 24-hour standard. Although the Birmingham area was initially designated as nonattainment for the 24-hour standard, in September 2010, the EPA determined that the area had attained the standard. The EPA is expected to propose new annual and 24-hour fine particulate matter standards during the summer of 2011.

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

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

Twenty-eight eastern states, including the 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 and operation of emissions controls at the Company's coal-fired facilities and/or by the purchase of emissions allowances.

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

The Clean Air Visibility Rule was finalized in July 2005, with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves the application of Best Available Retrofit Technology (BART) to certain sources built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter. For power plants, the Clean Air Visibility Rule allows states to determine that CAIR satisfies BART requirements for SO_2 and NO_x, and no additional controls beyond CAIR are anticipated to be necessary at any of the Company's facilities. The State of 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 establish emission limitations for numerous hazardous air pollutants, including mercury. As part of a proceeding in the U.S. District Court for the District of Columbia, the EPA has entered into a consent decree that requires the EPA to issue a proposed MACT rule by March 16, 2011 and a final rule by November 16, 2011.

The impacts of the eight-hour ozone, fine particulate matter, SO_2 and NO_2 standards, the proposed Transport Rule, the Clean Air Visibility Rule, and the proposed MACT rule for 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 pending and future legal challenges, and the development and implementation of rules at the state level. However, these additional regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

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

Water Quality

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

In December 2009, the EPA announced its determination that revision of the current effluent guidelines for steam electric power plants is warranted, and the EPA has announced its intention to adopt such revisions by January 2014. New wastewater treatment requirements are expected and may result in the installation of additional controls on certain 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 Company currently operates six electric generating plants with on-site coal combustion byproduct storage facilities (some with both "wet" (ash ponds) and "dry" (landfill) storage facilities). In addition to on-site storage, the Company also sells a portion of its coal combustion byproducts to third parties for beneficial reuse (approximately one-fourth in recent years). Historically, individual states have regulated coal combustion byproducts and the states in Southern Company's service territory, including the State of Alabama, each have their own regulatory parameters. The Company has a routine and robust inspection program in place to ensure the integrity of its coal ash surface impoundments and compliance with applicable regulations.

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

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

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

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

Global Climate Issues

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

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

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

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

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

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

In 2009, the total carbon dioxide emissions from the fossil fuel-fired electric generating units owned by the Company were approximately 43 million metric tons. The preliminary estimate of carbon dioxide emissions from these units in 2010 is approximately 45 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 2010 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 initiated 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.

On March 31, 2010, the FERC issued a new 30-year license for the Lewis Smith and Bankhead developments on the Warrior River. The new license authorizes the Company to continue operating these facilities in a manner consistent with past operations. On April 30, 2010, a stakeholders group filed a request for rehearing of the FERC order issuing the new license. On May 27, 2010, the FERC granted the rehearing request for the limited purpose of allowing the FERC additional time to consider the substantive issues raised in the request. The ultimate outcome of this matter cannot be determined at this 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 be determined at this time.

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% 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.

The Rate RSE increase for 2010 was 3.24%, or $152 million annually, and was effective in January 2010. In December 2010, the Company made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2011 and earnings were within the specified return range. Consequently, the retail rates will remain unchanged in 2011 under Rate RSE. Under the terms of Rate RSE, the maximum increase for 2012 cannot exceed 5.00%.

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 2008 or 2009. Effective April 2010, Rate CNP was reduced by 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. It is estimated that there will be a slight decrease to the current Rate CNP effective April 2011.

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 certain invested capital. Retail rates increased approximately 2.4% in January 2008 and 4.3% in January 2010 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, 2010, the Company submitted calculations associated with its cost of complying with environmental mandates, as provided under Rate CNP Environmental. The filing reflects an incremental increase in the revenue requirement associated with such environmental compliance, which would be recoverable in the billing months of January 2011 through December 2011. In order to afford additional rate stability to customers as the economy continues to recover from the recession, the Alabama PSC ordered on January 4, 2011 that the Company leave in effect for 2011 the factors associated with the Company's environmental compliance costs for the year 2010. Any recoverable amounts associated with 2011 will be reflected in the 2012 filing. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate CNP" for further information. The ultimate outcome of this matter cannot be determined at this time.

Fuel Cost Recovery

The Company has established fuel cost recovery rates under Rate ECR as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. The Company, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on the Company's net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per KWH. The Rate ECR factor as of January 1, 2011 was 2.403 cents per KWH. Effective with billings beginning in April 2011, the Rate ECR factor will be 2.681 cents per KWH.

As of December 31, 2010, the Company had an under recovered fuel balance of approximately $4 million which is included in deferred under recovered regulatory clause revenues in the balance sheets. As of December 31, 2009, the Company had an over recovered fuel balance of approximately $200 million, of which approximately $22 million was included in deferred over 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 expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate Natural Disaster Reserve (Rate NDR) charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. The second component of the Rate 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 Rate 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.

As revenue from the Rate NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, the Rate NDR charge will not have an effect on net income but will impact operating cash flows.

On August 20, 2010, the Alabama PSC approved an order enhancing the NDR that eliminated the $75 million authorized limit and allows the Company to make additional accruals to the NDR. The order also allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million. The Company may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance the Company's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear. The structure of the monthly Rate NDR charge to customers is not altered and continues to include a component to maintain the reserve.

For the year ended December 31, 2010, the Company accrued an additional $48 million to the NDR, resulting in an accumulated balance of approximately $127 million. For the year ended December 31, 2009, the Company accrued an additional $40 million to the NDR, resulting in an accumulated balance of approximately $75 million. These accruals are included in the balance sheets under other regulatory liabilities, deferred and are reflected as operations and maintenance expense in the statements of income.

Steam Service

In February 2009, the Alabama PSC granted a Certificate of Abandonment of Steam Service for the downtown area of the City of Birmingham. The order allows the Company to discontinue general steam service by the earlier of three years from May 14, 2008 or when it has no such remaining steam service customers. The Company was also authorized to honor other contractual obligations to provide steam service, which extend 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.

Nuclear Outage Accounting Order

On August 17, 2010, the Alabama PSC approved a change to the nuclear maintenance outage accounting process associated with routine refueling activities. Previously, the Company accrued nuclear outage operations and maintenance expenses for the two units of Plant Farley during the 18-month cycle for the outages. In accordance with the new order, nuclear outage expenses will be deferred when the charges actually occur and then amortized over the subsequent 18-month period.

The initial result of implementation of the new accounting order is that no nuclear maintenance outage expenses will be recognized from January 2011 through December 2011, which will decrease nuclear outage operations and maintenance expenses in 2011 from 2010 by approximately $50 million. During the fall of 2011, actual nuclear outage expenses associated with one unit of Plant Farley will be deferred to a regulatory asset account; beginning in January 2012, these deferred costs will be amortized to nuclear operations and maintenance expenses over an 18-month period. During the spring of 2012, actual nuclear outage expenses associated with the other unit of Plant Farley will be deferred to a regulatory asset account; beginning in July 2012, these deferred costs will be amortized to nuclear operations and maintenance expenses over an 18-month period. The Company will continue the pattern of deferral of nuclear outage expenses as incurred and the recognition of expenses over a subsequent 18-month period.

Legislation

Stimulus Funding

On April 28, 2010, Southern Company signed a Smart Grid Investment Grant agreement with the U.S. Department of Energy (DOE), formally accepting a $165 million grant under the American Recovery and Reinvestment Act of 2009 (ARRA). This funding will be used for transmission and distribution automation and modernization projects that must be completed by April 28, 2013. The Company will receive, and will match, $65 million under this agreement.

On May 12, 2010, the Company signed an agreement with the DOE formally accepting a $6 million grant under the ARRA. This funding will be used for hydro generation upgrades. The total upgrade project is expected to cost $30 million and the Company plans to spend $24 million on the project.

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

Healthcare Reform

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

Income Tax Matters

Tax Method of Accounting for Repairs

The Company submitted a change in the tax accounting method for repair costs associated with the Company's generation, transmission, and distribution systems with the filing of the 2009 federal income tax return in September 2010. The new tax method resulted in net positive cash flow in 2010 of approximately $141 million for the Company. Although the Internal Revenue Service (IRS) approval of this change is considered automatic, the amount claimed is subject to review because the IRS will be issuing final guidance on this matter. Currently, the IRS is working with the utility industry in an effort to resolve this matter in a consistent manner for all utilities. Due to uncertainty concerning the ultimate resolution of this matter, an unrecognized tax benefit has been recorded for the change in the tax accounting method for repair costs. See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information. The ultimate outcome of this matter cannot be determined at this time.

Bonus Depreciation

On September 27, 2010, the Small Business Jobs and Credit Act of 2010 (SBJCA) was signed into law. The SBJCA includes an extension of the 50% bonus depreciation for certain property acquired and placed in service in 2010 (and for certain long-term construction projects to be placed in service in 2011). Additionally, on December 17, 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term construction projects to be placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term construction projects to be placed in service in 2013), which could have a significant impact on the future cash flows of the Company. The application of the bonus depreciation provisions in these acts in 2010 provided approximately $132 million in increased cash flow. The Company estimates the potential increased cash flow for 2011 to be between approximately $150 million and $200 million.

Internal Revenue Code Section 199 Domestic Production Deduction

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

Other Matters

In accordance with accounting standards related to employers' accounting for pensions, the Company recorded non-cash pre-tax pension income of approximately $19 million, $24 million, and $26 million in 2010, 2009, and 2008, respectively. Postretirement benefit costs for the Company were $14 million, $19 million, and $23 million in 2010, 2009, and 2008, 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 U.S. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on the Company's financial statements. See Note 3 to the financial statements for information regarding material issues.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the

Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

The Company is subject to retail regulation by the 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 results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that potentially subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and, in accordance with GAAP, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's financial statements.

These events or conditions include the following:

- Changes in existing state or federal regulation by governmental authorities having jurisdiction over air quality, water quality, coal combustion byproducts, including coal ash, control of toxic substances, hazardous and solid wastes, and other environmental matters.
- Changes in existing income tax regulations or changes in IRS or 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. Recorded revenue includes both billed and unbilled KWH sales. Billings to individual customers are based on the reading of their meters, which is performed on a systematic basis throughout the month.

The Company's unbilled KWH sales include a measured component and an estimated component. Automated meters measure unbilled energy delivered through month-end. Readings from these meters are used to determine the measured unbilled KWH sales and associated revenues.

At month-end for customers where automated meter readings are not available, amounts of unbilled electricity delivered are estimated. Components of the estimate 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, estimated unbilled revenues could be significantly affected. However, as of December 31, 2010, the measured unbilled KWH sales are greater than the estimated unbilled KWH sales.

Pension and Other Postretirement Benefits

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

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

A 25 basis point change in any significant assumption would result in a $6 million or less change in total benefit expense and a $73 million or less change in projected obligations.

FINANCIAL CONDITION AND LIQUIDITY

Overview

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

The Company's investments in the qualified pension plan and the nuclear decommissioning trust funds remained stable in value as of December 31, 2010. In December 2010, the Company contributed $38 million to the qualified pension plan. The Company's funding obligations for the nuclear decommissioning trust fund are based on the site study, and the next study is expected to be conducted in 2013.

Net cash provided from operating activities in 2010 totaled $1.4 billion, a decrease of $231 million as compared to 2009. The decrease in cash provided from operating activities was primarily due to receivables and other current liabilities related to less cash collections of regulatory clause revenues when compared to the prior year. This is partially offset by an increase in deferred income taxes related to bonus depreciation. 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, 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 and higher depreciation along with a decrease in the payments for federal taxes as compared to 2007.

Net cash used for investing activities totaled $1.0 billion, $1.2 billion, and $1.6 billion for 2010, 2009, and 2008, respectively, primarily due to gross property additions to utility plant of $0.9 billion, $1.2 billion, and $1.5 billion for 2010, 2009, and 2008, 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 $600 million in 2010 primarily due to payment of common stock dividends. In 2009, net cash used for financing activities totaled $35 million primarily due to redemptions of debt securities and dividends paid in excess of debt issuances and cash raised from common stock sales. In 2008, net cash provided from financing activities totaled $375 million 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 the maturity or redemption of securities.

Significant balance sheet changes for 2010 included increases of $454 million in accumulated deferred income taxes, $340 million in gross plant related to environmental mandates and transmission and distribution projects, $124 million in prepaid pension costs, $101 million in deferred charges related to income taxes, and a $214 million decrease in cash and cash equivalents. In 2009, significant balance sheet changes included 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.

The Company's ratio of common equity to total capitalization, including short-term debt, was 44.0% in 2010, 43.3% in 2009, and 42.5% in 2008. See Note 6 to the financial statements for additional information.

Sources of Capital

The Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past. The Company has primarily utilized funds from operating cash flows, short-term debt, security issuances, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing 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 (SEC) 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, 2010, the Company had approximately $154 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 $506 million will expire at various times during 2011. $372 million of the credit facilities expiring in 2011 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. During 2010, the Company remarketed $307 million of pollution control revenue bonds. The amount of variable rate pollution control revenue bonds requiring liquidity support is $798 million as of December 31, 2010.

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, 2010 or December 31, 2009.

During 2010, the Company had an average of $7 million of commercial paper outstanding at a weighted average interest rate of 0.22% per annum and the maximum amount outstanding was $135 million. During 2009, the Company had an average of $30 million of commercial paper outstanding at a weighted average interest rate of 0.23% per annum and the maximum amount outstanding was $237 million. Management believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and cash.

Financing Activities

In October 2010, the Company issued $250 million aggregate principal amount of Series 2010A 3.375% Senior Notes due October 1, 2020. The net proceeds were used for the redemption of $150 million aggregate principal amount of the Company's Series AA 5.625% Senior Notes due April 15, 2034 and for other general corporate purposes, including the Company's continuous construction program.

In December 2010, the Company's $100 million Series R 4.70% Senior Notes due December 1, 2010 matured.

Subsequent to December 31, 2010, the Company's $200 million Series HH 5.10% Senior Notes due February 1, 2011 matured.

Subsequent to December 31, 2010, the Company entered into forward-starting interest rate swaps to mitigate exposure to interest rate changes related to an anticipated debt issuance. The notional amount of the swaps totaled $200 million.

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 below BBB- and/or Baa3. These contracts are primarily for physical electricity purchases, fuel purchases, fuel transportation and storage, and energy price risk management. At December 31, 2010, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $322 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 regulation and other various cost recovery mechanisms, the Company continues to have 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. 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.

To mitigate future exposure to changes in interest rates, the Company enters into derivatives that have been designated as hedges. The weighted average interest rate on $989 million of long-term variable interest rate exposure that has not been hedged at January 1, 2011 was 0.95%. 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 $9.9 million at January 1, 2011. For further information, see Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements.

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

In addition, 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, the majority of which are composed of regulatory hedges, for the years ended December 31 were as follows:

	2010 Changes	2009 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$(44)**	$(92)
Contracts realized or settled	**61**	123
Current period changes[a]	**(55)**	(75)
Contracts outstanding at the end of the period, assets (liabilities), net	**$(38)**	$(44)

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

The change in the fair value positions of the energy-related derivative contracts for the year ended December 31, 2010 was an increase of $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 the price of natural gas. At December 31, 2010, the Company had a net hedge volume of 33.9 million mmBtu with a weighted average contract cost approximately $1.14 per mmBtu above market prices, and 36.3 million mmBtu at December 31, 2009 with a weighted average contract cost approximately $1.22 per mmBtu above market prices. All of the natural gas hedges are recovered through the Company's fuel cost recovery clause.

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

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

	December 31, 2010 Fair Value Measurements			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
	(in millions)			
Level 1	$ -	$ -	$ -	$-
Level 2	(38)	(30)	(8)	-
Level 3	-	-	-	-
Fair value of contracts outstanding at end of period	$(38)	$(30)	$(8)	$-

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 Investors Service and Standard & Poor's, a division of The McGraw Hill Companies, Inc., or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements.

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

Capital Requirements and Contractual Obligations

The approved construction program of the Company includes a base level investment of $0.9 billion for 2011, $0.9 billion for 2012, and $1.1 billion for 2013. Over the next three years, the Company estimates spending $579 million on Plant Farley (including nuclear fuel), $886 million on distribution facilities, and $548 million on transmission additions. Also included in the Company's approved construction program are estimated environmental expenditures to comply with existing statutes and regulations of $47 million, $26 million, and $53 million for 2011, 2012, and 2013, respectively. The Company currently anticipates that additional environmental expenditures may be required to comply with anticipated new statutes and regulations. Such additional environmental expenditures are estimated to be in amounts up to $48 million, $108 million, and $354 million for 2011, 2012, and 2013, respectively. These potential incremental investments are not included in the approved construction program. See Note 7 to the financial statements under "Construction Program" for additional details. The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; changes in generating plants, including unit retirements and replacements, to meet new regulatory requirements; changes in FERC rules and regulations; Alabama PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

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 $950 million will be required by the end of 2013 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 detailed in the contractual obligations table that follows. See Notes 1, 6, 7, and 11 to the financial statements for additional information.

Contractual Obligations

	2011	2012-2013	2014-2015	After 2015	Uncertain Timing [d]	Total
			(in millions)			
Long-term debt[a] –						
Principal	$ 200	$ 750	$ 54	$ 5,182	$ -	$ 6,186
Interest	290	536	483	4,308	-	5,617
Preferred and preference stock dividends[b]	39	79	79	-	-	197
Energy-related derivative obligations[c]	31	9	-	-	-	40
Operating leases	20	29	13	8	-	70
Unrecognized tax benefits and interest[d]	-	-	-	-	45	45
Purchase commitments[e] –						
Capital[f]	834	1,900	-	-	-	2,734
Limestone[g]	16	33	28	49	-	126
Coal	1,304	1,441	861	579	-	4,185
Nuclear fuel	83	94	86	222	-	485
Natural gas[h]	288	402	280	147	-	1,117
Purchased power	30	62	75	270		437
Long-term service agreements[i]	23	41	35	18		117
Pension and other postretirement benefit plans[j]	9	17	-	-	-	26
Total	$3,167	$5,393	$1,994	$10,783	$45	$21,382

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2011, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts (shown separately).

(b) Preferred and preference stock 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 $45 million in unrecognized tax benefits and corresponding interest payments in individual years beyond 12 months cannot be reasonably and reliably estimated due to uncertainties in the timing of the effective settlement of tax positions. 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 2010, 2009, and 2008 were $1.4 billion, $1.2 billion, and $1.3 billion, respectively.

(f) The Company provides forecasted capital expenditures for a three-year period. Amounts represent current estimates of total expenditures, excluding those amounts related to contractual purchase commitments for nuclear fuel. Such amounts exclude the Company's estimates of potential incremental investments to comply with anticipated new environmental regulations of up to $48 million, $108 million, and $354 million for 2011, 2012, and 2013, respectively. At December 31, 2010, significant purchase commitments were outstanding in connection with the construction program.

(g) As part of the Company's program to reduce SO_2 emissions from 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, 2010.

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

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

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2010 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales and retail rates, customer growth, economic recovery, storm damage cost recovery and repairs, fuel cost recovery and other rate actions, environmental regulations and expenditures, access to sources of capital, projections for the qualified pension plan, postretirement benefit plan, and nuclear decommissioning trust fund 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 recent healthcare legislation, impact of the Small Business Jobs and Credit Act of 2010, impact of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, estimated sales and purchases under new power sale and purchase agreements, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, implementation of the Energy Policy Act of 2005, environmental laws including regulation of water quality, coal combustion byproducts, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including FERC matters and the pending EPA civil action against the Company;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the recent recession, population 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 trust funds;
- 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, 2010, 2009, and 2008

Alabama Power Company 2010 Annual Report

	2010	2009	2008
		(in millions)	
Operating Revenues:			
Retail revenues	**$5,076**	$4,497	$4,862
Wholesale revenues, non-affiliates	**465**	620	712
Wholesale revenues, affiliates	**236**	237	308
Other revenues	**199**	175	195
Total operating revenues	**5,976**	5,529	6,077
Operating Expenses:			
Fuel	**1,851**	1,824	2,184
Purchased power, non-affiliates	**72**	88	179
Purchased power, affiliates	**208**	219	359
Other operations and maintenance	**1,418**	1,211	1,259
Depreciation and amortization	**606**	545	520
Taxes other than income taxes	**332**	322	307
Total operating expenses	**4,487**	4,209	4,808
Operating Income	**1,489**	1,320	1,269
Other Income and (Expense):			
Allowance for equity funds used during construction	**36**	79	46
Interest income	**17**	17	19
Interest expense, net of amounts capitalized	**(303)**	(298)	(279)
Other income (expense), net	**(30)**	(25)	(32)
Total other income and (expense)	**(280)**	(227)	(246)
Earnings Before Income Taxes	**1,209**	1,093	1,023
Income taxes	**463**	384	368
Net Income	**746**	709	655
Dividends on Preferred and Preference Stock	**39**	39	39
Net Income After Dividends on Preferred and Preference Stock	**$ 707**	$ 670	$ 616

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2010, 2009, and 2008
Alabama Power Company 2010 Annual Report

	2010	2009	2008
		(in millions)	
Operating Activities:			
Net income	**$ 746**	$ 709	$ 655
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization, total	**694**	637	600
Deferred income taxes	**410**	(66)	127
Allowance for equity funds used during construction	**(36)**	(79)	(46)
Pension, postretirement, and other employee benefits	**(15)**	(8)	-
Pension and postretirement funding	**(55)**	(17)	(26)
Stock based compensation expense	**5**	4	3
Natural disaster reserve	**52**	55	16
Other, net	**(27)**	8	12
Changes in certain current assets and liabilities --			
-Receivables	**(29)**	310	(32)
-Fossil fuel stock	**(1)**	(77)	(134)
-Materials and supplies	**(20)**	(22)	(18)
-Other current assets	**(4)**	(16)	(1)
-Accounts payable	**(54)**	(19)	(9)
-Accrued taxes	**(140)**	24	37
-Accrued compensation	**28**	(32)	(5)
-Other current liabilities	**(181)**	193	-
Net cash provided from operating activities	**1,373**	1,604	1,179
Investing Activities:			
Property additions	**(903)**	(1,234)	(1,478)
Investment in restricted cash from pollution control bonds	**-**	(6)	(96)
Distribution of restricted cash from pollution control bonds	**18**	49	36
Nuclear decommissioning trust fund purchases	**(237)**	(245)	(301)
Nuclear decommissioning trust fund sales	**236**	244	300
Cost of removal net of salvage	**(44)**	(38)	(42)
Change in construction payables	**(45)**	26	42
Other investing activities	**(12)**	(25)	(61)
Net cash used for investing activities	**(987)**	(1,229)	(1,600)
Financing Activities:			
Increase (decrease) in notes payable, net	**-**	(25)	25
Proceeds --			
Common stock issued to parent	**-**	203	300
Capital contributions from parent company	**28**	24	21
Pollution control revenue bonds	**-**	79	265
Senior notes issuances	**250**	500	850
Redemptions --			
Preferred stock	**-**	-	(125)
Pollution control revenue bonds	**-**	-	(11)
Senior notes	**(250)**	(250)	(410)
Payment of preferred and preference stock dividends	**(39)**	(39)	(41)
Payment of common stock dividends	**(586)**	(523)	(491)
Other financing activities	**(3)**	(4)	(8)
Net cash provided from (used for) financing activities	**(600)**	(35)	375
Net Change in Cash and Cash Equivalents	**(214)**	340	(46)
Cash and Cash Equivalents at Beginning of Year	**368**	28	74
Cash and Cash Equivalents at End of Year	**$ 154**	$ 368	$ 28
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $14, $33 and $20 capitalized, respectively)	**$288**	$255	$259
Income taxes (net of refunds)	**188**	426	214
Noncash transactions - accrued property additions at year-end	**28**	74	107

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

BALANCE SHEETS

At December 31, 2010 and 2009

Alabama Power Company 2010 Annual Report

Assets	**2010**	2009
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 154**	$ 368
Restricted cash	**18**	37
Receivables --		
Customer accounts receivable	**362**	322
Unbilled revenues	**153**	135
Under recovered regulatory clause revenues	**5**	37
Other accounts and notes receivable	**35**	34
Affiliated companies	**57**	62
Accumulated provision for uncollectible accounts	**(10)**	(10)
Fossil fuel stock, at average cost	**391**	395
Materials and supplies, at average cost	**346**	326
Vacation pay	**55**	54
Prepaid expenses	**208**	111
Other regulatory assets, current	**38**	34
Other current assets	**10**	6
Total current assets	**1,822**	1,911
Property, Plant, and Equipment:		
In service	**19,966**	18,575
Less accumulated provision for depreciation	**6,931**	6,559
Plant in service, net of depreciation	**13,035**	12,016
Nuclear fuel, at amortized cost	**283**	253
Construction work in progress	**547**	1,256
Total property, plant, and equipment	**13,865**	13,525
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**64**	60
Nuclear decommissioning trusts, at fair value	**552**	490
Miscellaneous property and investments	**71**	69
Total other property and investments	**687**	619
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**488**	387
Prepaid pension costs	**257**	133
Deferred under recovered regulatory clause revenues	**4**	-
Other regulatory assets, deferred	**675**	750
Other deferred charges and assets	**196**	199
Total deferred charges and other assets	**1,620**	1,469
Total Assets	**$17,994**	$17,524

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

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

Liabilities and Stockholder's Equity	**2010**	2009
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 200**	$ 100
Accounts payable --		
Affiliated	**210**	195
Other	**273**	328
Customer deposits	**86**	87
Accrued taxes --		
Accrued income taxes	**2**	15
Other accrued taxes	**32**	32
Accrued interest	**63**	65
Accrued vacation pay	**45**	45
Accrued compensation	**99**	71
Liabilities from risk management activities	**31**	38
Over recovered regulatory clause revenues	**22**	182
Other current liabilities	**41**	40
Total current liabilities	**1,104**	1,198
Long-Term Debt (See accompanying statements)	**5,987**	6,082
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**2,747**	2,293
Deferred credits related to income taxes	**85**	89
Accumulated deferred investment tax credits	**157**	165
Employee benefit obligations	**311**	388
Asset retirement obligations	**520**	491
Other cost of removal obligations	**701**	668
Other regulatory liabilities, deferred	**217**	169
Deferred over recovered regulatory clause revenues	**-**	22
Other deferred credits and liabilities	**87**	37
Total deferred credits and other liabilities	**4,825**	4,322
Total Liabilities	**11,916**	11,602
Redeemable Preferred Stock (See accompanying statements)	**342**	342
Preference Stock (See accompanying statements)	**343**	343
Common Stockholder's Equity (See accompanying statements)	**5,393**	5,237
Total Liabilities and Stockholder's Equity	**$17,994**	$17,524
Commitments and Contingent Matters (See notes)		

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

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

	2010	2009	**2010**	2009
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term debt payable to affiliated trusts --				
Variable rate (3.39% at 1/1/11) due 2042	**$ 206**	$ 206		
Long-term notes payable --				
4.70% due 2010	**-**	100		
5.10% due 2011	**200**	200		
4.85% due 2012	**500**	500		
5.80% due 2013	**250**	250		
3.375% to 6.375% due 2016-2047	**3,875**	3,775		
Total long-term notes payable	**4,825**	4,825		
Other long-term debt --				
Pollution control revenue bonds --				
1.40% to 5.00% due 2030-2038	**367**	554		
Variable rates (0.26% to 0.44% at 1/1/11) due 2015-2038	**788**	601		
Total other long-term debt	**1,155**	1,155		
Unamortized debt premium (discount), net	**1**	(4)		
Total long-term debt (annual interest requirement -- $290.4 million)	**6,187**	6,182		
Less amount due within one year	**200**	100		
Long-term debt excluding amount due within one year	**5,987**	6,082	**49.6%**	50.7%

STATEMENTS OF CAPITALIZATION (continued)
At December 31, 2010 and 2009
Alabama Power Company 2010 Annual Report

	2010	2009	**2010**	2009
	(in millions)		*(percent of total)*	
Redeemable Preferred Stock:				
Cumulative redeemable preferred stock				
$100 par or stated value -- 4.20% to 4.92%				
Authorized - 3,850,000 shares				
Outstanding - 475,115 shares	**48**	48		
$1 par value -- 5.20% to 5.83%				
Authorized - 27,500,000 shares				
Outstanding - 12,000,000 shares: $25 stated value				
(annual dividend requirement -- $18.1 million)	**294**	294		
Total redeemable preferred stock	**342**	342	**2.8**	2.8
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				
(annual dividend requirement -- $21.4 million)	**343**	343	**2.9**	2.9
Common Stockholder's Equity:				
Common stock, par value $40 per share --				
Authorized: 40,000,000 shares				
Outstanding: 30,537,500 shares	**1,222**	1,222		
Paid-in capital	**2,156**	2,119		
Retained earnings	**2,022**	1,901		
Accumulated other comprehensive income (loss)	**(7)**	(5)		
Total common stockholder's equity	**5,393**	5,237	**44.7**	43.6
Total Capitalization	**$12,065**	$12,004	**100.0%**	100.0%

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

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2010, 2009, and 2008
Alabama Power Company 2010 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
				(in millions)		
Balance at December 31, 2007	18	$719	$2,065	$1,631	$(4)	$4,411
Net income after dividends on preferred and preference stock	-	-	-	616	-	616
Issuance of common stock	7	300	-	-	-	300
Capital contributions from parent company	-	-	26	-	-	26
Other comprehensive income (loss)	-	-	-	-	(6)	(6)
Cash dividends on common stock	-	-	-	(491)	-	(491)
Other	-	-	-	(2)	-	(2)
Balance at December 31, 2008	25	1,019	2,091	1,754	(10)	4,854
Net income after dividends on preferred and preference stock	-	-	-	670	-	670
Issuance of common stock	5	203	-	-	-	203
Capital contributions from parent company	-	-	28	-	-	28
Other comprehensive income (loss)	-	-	-	-	5	5
Cash dividends on common stock	-	-	-	(523)	-	(523)
Other	1	-	-	-	-	-
Balance at December 31, 2009	**31**	**1,222**	**2,119**	**1,901**	**(5)**	**5,237**
Net income after dividends on preferred and preference stock	**-**	**-**	**-**	**707**	**-**	**707**
Capital contributions from parent company	**-**	**-**	**37**	**-**	**-**	**37**
Other comprehensive income (loss)	**-**	**-**	**-**	**-**	**(2)**	**(2)**
Cash dividends on common stock	**-**	**-**	**-**	**(586)**	**-**	**(586)**
Balance at December 31, 2010	**31**	**$1,222**	**$2,156**	**$2,022**	**$(7)**	**$5,393**

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

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

	2010	2009	2008
		(in millions)	
Net income after dividends on preferred and preference stock	**$707**	$670	$616
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $-, $(2), and $(4), respectively	**-**	(3)	(8)
Reclassification adjustment for amounts included in net income, net of tax of $(1), $5, and $1, respectively	**(2)**	8	2
Total other comprehensive income (loss)	**(2)**	5	(6)
Comprehensive Income	**$705**	$675	$610

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

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

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations and power pool transactions. Costs for these services amounted to $371 million, $325 million, and $321 million during 2010, 2009, and 2008, respectively. Cost allocation methodologies used by SCS were approved by the Securities and Exchange Commission (SEC) 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 $218 million, $183 million, and $196 million during 2010, 2009, and 2008, 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 $11 million in 2010, $10 million in 2009, and $11 million in 2008. 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 million in

2008. In addition, the Company purchased synthetic fuel from AFP for use at several of the Company's plants. Synthetic fuel purchases totaled $6 million in 2008.

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 2010, 2009, and 2008, the Company billed Southern Power $1 million, $1 million, and $1 million, respectively, under these agreements. Under a power purchase agreement (PPA) with Southern Power, the Company's purchased power costs from Plant Harris in 2010, 2009, and 2008 totaled $15 million, $62 million, and $63 million, respectively. The Company also provides the fuel, at cost, associated with the PPA. The fuel cost recognized by the Company was $21 million in 2010, $63 million in 2009, and $120 million in 2008. The Company recorded no prepaid capacity expenses in 2010 due to the expiration of the PPA with Southern Power in May 2010. 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 and 2008. See Note 3 under "Retail Regulatory Matters" and Note 7 under "Purchased Power Commitments" for additional information.

The Company has an agreement with Gulf Power under which the Company will make transmission system upgrades to ensure firm delivery of energy under a non-affiliate PPA. In March 2009, Gulf Power entered into a PPA for the capacity and energy from a combined cycle plant located in Autauga County, Alabama. The total cost committed by the Company related to the upgrades is approximately $82 million over the next four years. The Company expects to recover a majority of these costs from Gulf Power over the next ten years.

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

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:

	2010	2009	Note
	(in millions)		
Deferred income tax charges	**$ 488**	$ 387	(a, j, l)
Loss on reacquired debt	**74**	74	(b)
Vacation pay	**55**	54	(c, k)
Under/(over) recovered regulatory clause revenues	**(13)**	(166)	(d)
Fuel-hedging (realized and unrealized) losses	**39**	45	(e)
Other assets	**30**	8	(f, g)
Asset retirement obligations	**(77)**	(43)	(a)
Other cost of removal obligations	**(701)**	(668)	(a)
Deferred income tax credits	**(85)**	(89)	(a)
Fuel-hedging (realized and unrealized) gains	**(1)**	(1)	(e)
Mine reclamation and remediation	**(10)**	(12)	(h)
Nuclear outage	**-**	(27)	(d)
Deferred purchased power	**-**	(8)	(g)
Natural disaster reserve	**(127)**	(75)	(i)
Other liabilities	**(3)**	(3)	(d)
Retiree benefit plans	**569**	657	(j, k)
Total assets (liabilities), net	**$ 238**	$ 133	

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 income 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 13.5 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 and potential reliability-related expenses are incurred, as approved by the Alabama PSC.

(j) Recovered and amortized over the average remaining service period which may range up to 15 years. See Note 2 for additional information.

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

(l) Included in the deferred income tax charges is $21 million for the retiree Medicare drug subsidy, which is recovered and amortized, as approved by the Alabama PSC, over the average remaining service period which may range up to 15 years. See Note 5 for additional information.

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off or reclassify to accumulated other comprehensive income (OCI) related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters" for additional information.

Revenues

Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract periods. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, 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:

	2010	2009
	(in millions)	
Generation	**$10,598**	$ 9,627
Transmission	**2,826**	2,702
Distribution	**5,267**	5,046
General	**1,262**	1,187
Plant acquisition adjustment	**12**	12
Total plant in service	**$19,965**	$18,574

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. During 2010, the Company accrued estimated nuclear refueling outage costs in advance of the unit’s next refueling outage. The refueling cycle is 18 months for each unit. During 2010, the Company accrued $53 million for the applicable refueling cycles and paid $80 million for outages at Plant Farley Units 1 and 2. At December 31, 2010, the reserve balance was zero.

On August 17, 2010, the Alabama PSC approved the Company's request to stop accruing for nuclear refueling outage costs in advance of the refueling outages when the most recent 18-month cycle ended in December 2010 and to begin deferring nuclear outage expenses. The amortization will begin after each outage has occurred and the associated outage expenses are known. The first 18-month amortization cycle for expenses associated with the fall 2011 outage will begin in January 2012. The second cycle will begin in July 2012 for expenses associated with the spring 2012 outage.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.3% in 2010 and 3.2% in 2009 and 2008. 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 are removed from the balance sheet accounts and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

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. In addition, the Company has retirement obligations related to various landfill sites, 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:

	2010	2009
	(in millions)	
Balance at beginning of year	**$491**	$461
Liabilities incurred	**-**	-
Liabilities settled	**(2)**	(1)
Accretion	**33**	31
Cash flow revisions [(a)]	**(2)**	-
Balance at end of year	**$520**	$491

(a) Updated based on results from the 2009 Nuclear Interim 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 and its affiliates are not allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the Company's management. The Funds' managers are authorized, within broad limits, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

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

At December 31, 2010, investment securities in the Funds totaled $552 million consisting of equity securities of $406 million, debt securities of $139 million, and $7 million of other securities. At December 31, 2009, investment securities in the Funds totaled $488 million consisting of equity securities of $346 million, debt securities of $134 million, and $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 $236 million, $244 million, and $300 million in 2010, 2009, and 2008, respectively, all of which were reinvested. For 2010, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $65 million, of which $31 million related to securities held in the Funds at December 31, 2010. For 2009, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $96 million, of which $80 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) million. While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of and purpose for which the securities were acquired.

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 Funds will provide the minimum funding amounts prescribed by the NRC.

At December 31, 2010, the accumulated provisions for decommissioning were as follows:

	(in millions)
External trust funds	$553
Internal reserves	24
Total	$577

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. 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 9.4% in 2010 and 9.2% in 2009 and 2008. AFUDC, net of income taxes, as a percent of net income after dividends on preferred and preference stock was 6.3% in 2010, 14.9% in 2009, and 9.4% in 2008.

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 expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate Natural Disaster Reserve (Rate NDR) charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. The second component of the Rate 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 Rate 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.

As revenue from the Rate NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, the Rate NDR charge will not have an effect on net income but will impact operating cash flows.

On August 20, 2010, the Alabama PSC approved an order enhancing the NDR that eliminated the $75 million authorized limit and allows the Company to make additional accruals to the NDR. The order also allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million. The Company may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance the Company's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear. The structure of the monthly Rate NDR charge to customers is not altered and continues to include a component to maintain the reserve.

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 excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the Alabama PSC-approved fuel hedging program. This results in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts are marked to market through current period income and are recorded on a net basis in the statements of income. See Note 11 for additional information.

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

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

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income after dividends on preferred and preference stock, 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 reflected as long-term debt in the balance sheets.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). In December 2010, the Company contributed approximately $38 million to the qualified pension plan. No contributions to the qualified pension plan are expected for the year ending December 31, 2011. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the Alabama PSC and the FERC. For the year ending December 31, 2011, other postretirement trust contributions are expected to total approximately $9 million.

Actuarial Assumptions

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

	2010	2009	2008
Discount rate:			
Pension plans	**5.52%**	5.93%	6.75%
Other postretirement benefit plans	**5.41**	5.84	6.75
Annual salary increase	**3.84**	4.18	3.75
Long-term return on plan assets:			
Pension plans	**8.75**	8.50	8.50
Other postretirement benefit plans	**7.43**	7.52	7.66

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

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

	1 Percent Increase	**1 Percent Decrease**
	(in millions)	
Benefit obligation	$32	$28
Service and interest costs	2	1

Pension Plans

The total accumulated benefit obligation for the pension plans was $1.7 billion in 2010 and $1.6 billion in 2009. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2010 and 2009 were as follows:

	2010	2009
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$1,675**	$1,460
Service cost	**41**	34
Interest cost	**97**	96
Benefits paid	**(81)**	(77)
Actuarial loss (gain)	**47**	162
Balance at end of year	**1,779**	1,675
Change in plan assets		
Fair value of plan assets at beginning of year	**1,712**	1,539
Actual return (loss) on plan assets	**258**	245
Employer contributions	**44**	5
Benefits paid	**(81)**	(77)
Fair value of plan assets at end of year	**1,933**	1,712
Prepaid pension asset, net	**$ 154**	$ 37

At December 31, 2010, the projected benefit obligations for the qualified and non-qualified pension plans were $1.7 billion and $103 million, respectively. All pension plan assets are related to the qualified pension plan.

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

	2010	2009
	(in millions)	
Prepaid pension costs	**$257**	$133
Other regulatory assets, deferred	**497**	549
Other current liabilities	**(7)**	(6)
Employee benefit obligations	**(96)**	(90)

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

	2010	2009	**Estimated Amortization in 2011**
		(in millions)	
Prior service cost	**$ 41**	$ 50	**$ 9**
Net (gain) loss	**456**	499	**4**
Other regulatory assets, deferred	**$497**	$549	

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

	Regulatory Assets
	(in millions)
Balance at December 31, 2008	$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
Net gain	**(42)**
Change in prior service costs	**1**
Reclassification adjustments:	
Amortization of prior service costs	**(9)**
Amortization of net gain	**(2)**
Total reclassification adjustments	**(11)**
Total change	**(52)**
Balance at December 31, 2010	**$497**

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

	2010	2009	2008
		(in millions)	
Service cost	**$ 41**	$ 34	$ 35
Interest cost	**97**	96	87
Expected return on plan assets	**(168)**	(164)	(160)
Recognized net (gain) loss	**2**	1	2
Net amortization	**9**	9	10
Net periodic pension cost (income)	**$ (19)**	$ (24)	$ (26)

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

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2010, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2011	$ 90
2012	95
2013	99
2014	103
2015	108
2016 to 2020	596

Other Postretirement Benefits

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

	2010	2009
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 461**	$ 446
Service cost	**6**	6
Interest cost	**26**	29
Benefits paid	**(26)**	(26)
Actuarial loss (gain)	**(16)**	19
Plan amendments	**-**	(15)
Retiree drug subsidy	**3**	2
Balance at end of year	**454**	461
Change in plan assets		
Fair value of plan assets at beginning of year	**295**	252
Actual return (loss) on plan assets	**35**	47
Employer contributions	**16**	20
Benefits paid	**(23)**	(24)
Fair value of plan assets at end of year	**323**	295
Accrued liability	**$(131)**	$(166)

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

	2010	2009
	(in millions)	
Regulatory assets	**$ 72**	$ 108
Employee benefit obligations	**(131)**	(166)

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

	2010	2009	Estimated Amortization in 2011
		(in millions)	
Prior service cost	**$ 30**	$ 33	**$ 4**
Net (gain) loss	**37**	67	**-**
Transition obligation	**5**	8	**3**
Regulatory assets	**$ 72**	$108	

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

	Regulatory Assets
	(in millions)
Balance at December 31, 2008	$135
Net gain	(4)
Change in prior service costs/transition obligation	(15)
Reclassification adjustments:	
Amortization of transition obligation	(4)
Amortization of prior service costs	(4)
Amortization of net gain	-
Total reclassification adjustments	(8)
Total change	(27)
Balance at December 31, 2009	108
Net gain	**(29)**
Change in prior service costs/transition obligation	**-**
Reclassification adjustments:	
Amortization of transition obligation	**(3)**
Amortization of prior service costs	**(4)**
Amortization of net gain	**-**
Total reclassification adjustments	**(7)**
Total change	**(36)**
Balance at December 31, 2010	**$ 72**

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

	2010	2009	2008
		(in millions)	
Service cost	**$ 6**	$ 6	$ 7
Interest cost	**26**	29	29
Expected return on plan assets	**(25)**	(24)	(22)
Net amortization	**7**	8	9
Net postretirement cost	**$ 14**	$ 19	$ 23

The Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (Medicare Act) provides a 28% prescription drug subsidy for Medicare eligible retirees. The effect of the subsidy reduced the Company's expenses for the years ended December 31, 2010, 2009, and 2008 by approximately $8 million, $9 million, and $11 million, respectively, and is expected to have a similar impact on future expenses.

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

	Benefit Payments	**Subsidy Receipts**	**Total**
		(in millions)	
2011	$ 29	$ (3)	$ 26
2012	31	(3)	28
2013	33	(3)	30
2014	35	(3)	32
2015	36	(4)	32
2016 to 2020	184	(22)	162

Benefit Plan Assets

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). In 2009, in determining the optimal asset allocation for the pension fund, the Company performed an extensive study based on projections of both assets and liabilities over a 10-year forward horizon. The primary goal of the study was to maximize plan funded status. The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

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

	Target	**2010**	2009
Pension plan assets:			
Domestic equity	29%	**29%**	33%
International equity	28	**27**	29
Fixed income	15	**22**	15
Special situations	3	**-**	-
Real estate investments	15	**13**	13
Private equity	10	**9**	10
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	47%	**41%**	42%
International equity	12	**16**	16
Domestic fixed income	32	**36**	35
Special situations	1	**-**	-
Real estate investments	5	**4**	4
Private equity	3	**3**	3
Total	100%	**100%**	100%

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

Investment Strategies

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

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

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

Benefit Plan Asset Fair Values

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

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

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

	Fair Value Measurements Using			
As of December 31, 2010:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Domestic equity*	$358	$144	$ -	$ 502
International equity*	361	125	-	486
Fixed income:				
U.S. Treasury, government, and agency bonds	-	86	-	86
Mortgage- and asset-backed securities	-	70	-	70
Corporate bonds	-	168	1	169
Pooled funds	-	57	-	57
Cash equivalents and other	1	135	-	136
Special situations	-	-	-	-
Real estate investments	52	-	191	243
Private equity	-	-	180	180
Total	$772	$785	$372	$1,929

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

As of December 31, 2009:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$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.

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

	2010		2009	
	Real Estate Investments	**Private Equity**	**Real Estate Investments**	**Private Equity**
		(in millions)		
Beginning balance	**$166**	**$169**	$254	$148
Actual return on investments:				
Related to investments held at year end	**14**	**9**	(72)	13
Related to investments sold during the year	**3**	**3**	(20)	3
Total return on investments	**17**	**12**	(92)	16
Purchases, sales, and settlements	**8**	**(1)**	4	5
Transfers into/out of Level 3	**-**	**-**	-	-
Ending balance	**$191**	**$180**	$166	$169

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

As of December 31, 2010:	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*	$62	$ 7	$ -	$ 69
International equity*	19	6	-	25
Fixed income:				
U.S. Treasury, government, and agency bonds	-	5	-	5
Mortgage- and asset-backed securities	-	4	-	4
Corporate bonds	-	9	-	9
Pooled funds	-	3	-	3
Cash equivalents and other	-	24	-	24
Trust-owned life insurance	-	159	-	159
Special situations	-	-	-	-
Real estate investments	3	-	10	13
Private equity	-	-	9	9
Total	$84	$217	$19	$320

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

As of December 31, 2009:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$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.

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

	2010		2009	
	Real Estate Investments	**Private Equity**	**Real Estate Investments**	**Private Equity**
		(in millions)		
Beginning balance	**$ 9**	**$10**	$15	$8
Actual return on investments:				
Related to investments held at year end	**1**	**-**	(5)	2
Related to investments sold during the year	**-**	**-**	(1)	-
Total return on investments	**1**	**-**	(6)	2
Purchases, sales, and settlements	**-**	**(1)**	-	-
Transfers into/out of Level 3	**-**	**-**	-	-
Ending balance	**$10**	**$ 9**	$9	$10

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2010, 2009, and 2008 were $18 million, $19 million, and $18 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as opacity and air and water quality standards, has increased generally throughout the U.S. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

In November 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including the Company, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. 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. The separate action against the Company is ongoing.

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. On September 2, 2010, the EPA dismissed five of its eight remaining claims against the Company, leaving only three claims for summary disposition or trial, including the claim relating to a facility co-owned by Mississippi Power. The parties each filed motions for summary judgment on September 30, 2010. The court has set a trial date for October 2011 for any remaining claims.

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures or affect the timing of currently budgeted capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

Carbon Dioxide Litigation

New York Case

In July 2004, three environmental groups and attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed complaints in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. The complaints allege that the companies' emissions of carbon dioxide, a greenhouse gas, contribute to global warming, which the plaintiffs assert is a public nuisance. Under common law public and private nuisance theories, the plaintiffs seek a judicial order (1) holding each defendant jointly and severally liable for creating, contributing to, and/or maintaining global warming and (2) requiring each of the defendants to cap its emissions of carbon dioxide and then reduce those emissions by a specified percentage each year for at least a decade. The plaintiffs have not, however, requested that damages be awarded in connection with their claims. Southern Company believes these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2005, the U.S. District Court for the Southern District of New York granted Southern Company's and the other defendants' motions to dismiss these cases. The plaintiffs filed an appeal to the U.S. Court of Appeals for the Second Circuit in October 2005, and, in September 2009, the U.S. Court of Appeals for the Second Circuit reversed the district court's ruling, vacating the dismissal of the plaintiffs' claim, and remanding the case to the district court. On December 6, 2010, the U.S. Supreme Court granted the defendants' petition for writ of certiorari. The ultimate outcome of these matters cannot be determined at this time.

Kivalina Case

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

Other Litigation

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

Environmental Remediation

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

Nuclear Fuel Disposal Costs

The Company has a contract with the U.S., 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, which the U.S. Court of Appeals for the Federal Circuit granted in April 2008. On May 5, 2010, the U.S. Court of Appeals for the Federal Circuit lifted the stay.

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

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.

Income Tax Matters

Tax Method of Accounting for Repairs

The Company submitted a change in the tax accounting method for repair costs associated with the Company's generation, transmission, and distribution systems with the filing of the 2009 federal income tax return in September 2010. The new tax method resulted in net positive cash flow in 2010 of approximately $141 million for the Company. Although IRS approval of this change is considered automatic, the amount claimed is subject to review because the IRS will be issuing final guidance on this matter. Currently, the IRS is working with the utility industry in an effort to resolve this matter in a consistent manner for all utilities. Due to uncertainty concerning the ultimate resolution of this matter, an unrecognized tax benefit has been recorded for the change in the tax accounting method for repair costs. See Note 5 under "Unrecognized Tax Benefits" for additional information. The ultimate outcome of this matter cannot be determined at this time.

Retail Regulatory Matters

Rate RSE

Rate stabilization and equalization plan (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% 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.

The Rate RSE increase for 2010 was 3.24%, or $152 million annually, and was effective in January 2010. In December 2010, the Company made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2011 and earnings were within the specified return range. Consequently, the retail rates will remain unchanged in 2011 under Rate RSE. Under the terms of Rate RSE, the maximum increase for 2012 cannot exceed 5.00%.

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 certificated new plant (Rate CNP). There was no adjustment to the Rate CNP to recover certificated PPA costs in 2008 or 2009. Effective April 2010, Rate CNP was reduced by 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. It is estimated that there will be a slight decrease to the current Rate CNP effective April 2011.

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 certain invested capital. Retail rates increased approximately 2.4% in January 2008 and 4.3% in January 2010 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, 2010, the Company submitted calculations associated with its cost of complying with environmental mandates, as provided under rate certificated new plant environmental. The filing reflects an incremental increase in the revenue requirement associated with such environmental compliance, which would be recoverable in the billing months of January 2011 through December 2011. In order to afford additional rate stability to customers as the economy continues to recover from the recession, the Alabama PSC ordered on January 4, 2011 that the Company leave in effect for 2011 the factors associated with the Company's environmental compliance costs for the year 2010. Any recoverable amounts associated with 2011 will be reflected in the 2012 filing. The ultimate outcome of this matter cannot be determined at this time.

Fuel Cost Recovery

The Company has established fuel cost recovery rates under rate energy cost recovery (Rate ECR) as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. The Company, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on the Company's net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per kilowatt-hour (KWH) sales. The Rate ECR factor as of January 1, 2011 is 2.403 cents per KWH. Effective with billings beginning in April 2011, the Rate ECR factor will be 2.681 cents per KWH.

As of December 31, 2010, the Company had an under recovered fuel balance of approximately $4 million which is included in deferred under recovered regulatory clause revenues in the balance sheets. As of December 31, 2009, the Company had an over recovered fuel balance of approximately $200 million, of which approximately $22 million was included in deferred over 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 expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate NDR charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. The second component of the Rate 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 Rate 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.

As revenue from the Rate NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, the Rate NDR charge will not have an effect on net income but will impact operating cash flows.

On August 20, 2010, the Alabama PSC approved an order enhancing the NDR that eliminated the \$75 million authorized limit and allows the Company to make additional accruals to the NDR. The order also allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds \$75 million. The Company may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance the Company's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear. The structure of the monthly Rate NDR charge to customers is not altered and continues to include a component to maintain the reserve.

For the year ended December 31, 2010, the Company accrued an additional \$48 million to the NDR, resulting in an accumulated balance of approximately \$127 million. For the year ended December 31, 2009, the Company accrued an additional \$40 million to the NDR, resulting in an accumulated balance of approximately \$75 million. These accruals are included in the balance sheets under other regulatory liabilities, deferred and are reflected as operations and maintenance expense in the statements of income.

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 \$101 million in 2010, \$82 million in 2009, and \$124 million in 2008, 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 \$25 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, 2010, the capitalization of SEGCO consisted of \$90 million of equity and \$75 million of long-term debt on which the annual interest requirement is \$3 million. SEGCO paid dividends of \$5 million in 2010, none in 2009, and \$8 million in 2008, 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, 2010 is as follows:

Facility	Total Megawatt Capacity	Company Ownership	Amount of Investment	Accumulated Depreciation
			(in millions)	
Greene County	500	60.00% (1)	$ 140	$ 76
Plant Miller				
Units 1 and 2	1,320	91.84% (2)	1,253	477

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

At December 31, 2010, the Company's portion of Plant Miller construction work in progress was $125 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:

	2010	2009	2008
		(in millions)	
Federal –			
Current	**$ 52**	$374	$198
Deferred	**333**	(41)	121
	$385	$333	$319
State –			
Current	**$ 1**	$ 76	$ 43
Deferred	**77**	(25)	6
	78	51	49
Total	**$463**	$384	$368

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2010	2009
	(in millions)	
Deferred tax liabilities:		
Accelerated depreciation	**$2,415**	$2,010
Property basis differences	**396**	376
Premium on reacquired debt	**31**	30
Pension and other benefits	**210**	184
Fuel clause under recovered	**10**	-
Regulatory assets associated with employee benefit obligations	**239**	295
Regulatory assets associated with asset retirement obligations	**220**	208
Other	**85**	82
Total	**3,606**	3,185
Deferred tax assets:		
Federal effect of state deferred taxes	**177**	88
State effect of federal deferred taxes	**50**	107
Unbilled revenue	**41**	29
Storm reserve	**41**	23
Pension and other benefits	**264**	334
Other comprehensive losses	**8**	9
Fuel clause over recovered	**-**	75
Asset retirement obligations	**220**	208
Other	**87**	93
Total	**888**	966
Total deferred tax liabilities, net	**2,718**	2,219
Portion included in current assets (liabilities), net	**29**	74
Accumulated deferred income taxes	**$2,747**	$2,293

At December 31, 2010, the Company's tax-related regulatory assets and liabilities were $488 million and $85 million, respectively. These assets are attributable to tax benefits that flowed through to customers in prior years, to deferred taxes previously recognized at rates lower than the current enacted tax law, and to taxes applicable to capitalized interest. In 2010, the Company deferred $21 million as a regulatory asset related to the impact of the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 (together, the Acts). The Acts eliminated the deductibility of health care costs that are covered by federal Medicare subsidy payments. The Company will amortize the regulatory asset to income tax expense over the average remaining service period which may range up to 15 years, as approved by the Alabama PSC. These liabilities are attributable to unamortized investment tax credits.

In accordance with regulatory requirements, deferred investment tax credits are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $8 million in each of 2010, 2009, and 2008. At December 31, 2010, all investment tax credits available to reduce federal income taxes payable had been utilized.

On September 27, 2010, the Small Business Jobs and Credit Act of 2010 (SBJCA) was signed into law. The SBJCA includes an extension of the 50% bonus depreciation for certain property acquired and placed in service in 2010 (and for certain long-term construction projects to be placed in service in 2011). Additionally, on December 17, 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term construction projects to be placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term construction projects to be placed in service in 2013). The application of the bonus depreciation provisions in these acts in 2010 significantly increased deferred tax liabilities related to accelerated depreciation.

Effective Tax Rate

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

	2010	2009	2008
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**4.2**	3.0	3.1
Non-deductible book depreciation	**0.8**	0.8	0.9
Differences in prior years' deferred and current tax rates	**(0.1)**	(0.2)	(0.1)
AFUDC-equity	**(1.0)**	(2.5)	(1.6)
Production activities deduction	**-**	(0.8)	(0.5)
Other	**(0.6)**	(0.2)	(0.8)
Effective income tax rate	**38.3%**	35.1%	36.0%

State income tax, net of federal deduction increased in 2010 due to a decrease in the state deduction for federal income taxes paid, which is a result of increased bonus depreciation and pension contributions.

The tax benefit of AFUDC-equity decreased in 2010 from prior years due to a decrease in AFUDC, resulting from the completion of construction projects related to environmental mandates at generating facilities. 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 Section 199 of the Internal Revenue Code (production activities deduction). The deduction is equal to a stated percentage of qualified production activities net income. The percentage was phased in over the years 2005 through 2010. For 2008 and 2009, a 6% reduction was available to the Company. Thereafter, the allowed rate is 9%; however, due to increased tax deductions from bonus depreciation and pension contributions there was no domestic production deduction available to the Company for 2010.

Unrecognized Tax Benefits

For 2010, the total amount of unrecognized tax benefits increased by $37 million, resulting in a balance of $43 million as of December 31, 2010.

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

	2010	2009	2008
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ 6**	$3	$5
Tax positions from current periods	**6**	2	1
Tax positions from prior periods	**31**	1	(2)
Reductions due to settlements	**-**	-	(1)
Reductions due to expired statute of limitations	**-**	-	-
Balance at end of year	**$43**	$6	$3

The tax positions increases from current periods and from prior periods relate primarily to the tax accounting method change for repairs and other miscellaneous uncertain tax positions. See Note 3 under "Income Tax Matters – Tax Method of Accounting for Repairs" for additional information.

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

	2010	2009	2008
		(in millions)	
Tax positions impacting the effective tax rate	**$ 6**	$6	$3
Tax positions not impacting the effective tax rate	**37**	-	-
Balance of unrecognized tax benefits	**$43**	$6	$3

The tax positions impacting the effective tax rate primarily relate to the production activities deduction tax position. The tax positions not impacting the effective tax rate relate to the timing difference associated with the tax accounting method change for repairs. These amounts are presented on a gross basis without considering the related federal or state income tax impact. See Note 3 under "Income Tax Matters – Tax Method of Accounting for Repairs" for additional information.

Accrued interest for unrecognized tax benefits was as follows:

	2010	2009	2008
		(in millions)	
Interest accrued at beginning of year	**$0.3**	$0.3	$0.4
Interest reclassified due to settlements	**-**	-	(0.3)
Interest accrued during the year	**1.2**	-	0.2
Balance at end of year	**$1.5**	$0.3	$0.3

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

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

6. FINANCING

Long-Term Debt Payable to Affiliated Trusts

The Company has formed certain wholly-owned trust subsidiaries for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the Company through the issuance of junior subordinated notes totaling $206 million, which constitute substantially all of the assets of these trusts and are reflected in the balance sheets as long-term debt 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, 2010, preferred securities of $200 million were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for these trusts and the related securities.

Securities Due Within One Year

At December 31, 2010 and 2009, the Company had scheduled maturities of senior notes due within one year totaling $200 million and $100 million, respectively.

Maturities of senior notes through 2015 applicable to total long-term debt are as follows: $200 million in 2011; $500 million in 2012; $250 million in 2013; and none in 2014 and 2015.

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 no obligations related to the issuance of pollution control revenue bonds in 2010. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

Senior Notes

The Company issued a total of $250 million of unsecured senior notes in 2010. The proceeds of these issuances were used to redeem $150 million aggregate principle amount of the Company's Series AA 5.625% Senior Notes due April 15, 2034 and for other general corporate purposes, including the Company's continuous construction program.

In December 2010, the Company's $100 million Series R 4.70% Senior Notes due December 1, 2010 matured.

Subsequent to December 31, 2010, the Company's $200 million Series HH 5.10% Senior Notes due February 1, 2011 matured.

At December 31, 2010 and 2009, the Company had $4.8 billion and $4.8 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, 2010.

Preference and Common Stock

In 2010, the Company issued no new shares of preference stock or common stock.

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 contain 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, 2010. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its other subsidiaries.

Bank Credit Arrangements

The Company maintains committed lines of credit in the amount of $1.3 billion, of which $506 million will expire at various times during 2011. $372 million of the credit facilities expiring in 2011 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. During 2010, the Company remarketed $307 million of pollution control revenue bonds. The amount of variable rate pollution control revenue bonds requiring liquidity support is $798 million as of December 31, 2010.

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, 2010, 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, 2010 and 2009, the Company had no commercial paper outstanding. During 2010 and 2009, the maximum amount outstanding for commercial paper was $135 million and $237 million, respectively. The average amount outstanding in 2010 and 2009 was $7 million and $30 million, respectively. The weighted average annual interest rate on commercial paper was 0.22% in 2010 and 0.23% in 2009. Short-term borrowings are included in notes payable in the balance sheets.

At December 31, 2010, the Company had regulatory approval to have outstanding up to $2.0 billion of short-term borrowings.

7. COMMITMENTS

Construction Program

The approved construction program of the Company includes a base level investment of $0.9 billion in 2011, $0.9 billion in 2012, and $1.1 billion in 2013. These amounts include $83 million, $59 million, and $35 million in 2011, 2012, and 2013, respectively, for construction expenditures related to contractual purchase commitments for nuclear fuel included herein under "Fuel Commitments." Also included in the Company's approved construction program are estimated environmental expenditures to comply with existing statutes and regulations of $47 million, $26 million, and $53 million for 2011, 2012, and 2013, respectively. The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; changes in generating plants, including unit retirement and replacement decisions, to meet new regulatory requirements; changes in FERC rules and regulations; Alabama PSC approvals; storm impacts; 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, 2010, significant purchase commitments were outstanding in connection with the ongoing construction program. The Company has no generating plants under construction. Construction of new transmission and distribution facilities and capital improvements, including those 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 $117 million over the remaining life of the agreements, which are currently estimated to range up to six 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 2.6 million tons, equating to approximately $126 million, through 2019. Estimated expenditures (based on minimum contracted obligated dollars) over the next five years are $16 million in 2011, $16 million in 2012, $17 million in 2013, $17 million in 2014, and $11 million in 2015.

Fuel Commitments

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement of fossil and nuclear fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Coal commitments include forward contract purchases for sulfur dioxide 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, 2010. Total estimated minimum long-term commitments at December 31, 2010 were as follows:

	Commitments		
	Natural Gas	Coal	Nuclear Fuel
		(in millions)	
2011	$ 288	$1,304	$ 83
2012	227	832	59
2013	175	609	35
2014	156	424	43
2015	124	437	43
2016 and thereafter	147	579	222
Total commitments	$1,117	$4,185	$485

Additional commitments for fuel will be required to supply the Company's future needs. Total charges for nuclear fuel included in fuel expense amounted to $79 million in 2010, $78 million in 2009, and $70 million in 2008.

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

Purchased Power Commitments

The Company has entered into various long-term commitments for the purchase of capacity and energy. Total estimated minimum long-term obligations at December 31, 2010 were as follows:

	Commitments
	Non-Affiliated
	(in millions)
2011	$ 30
2012	31
2013	31
2014	37
2015	38
2016 and thereafter	270
Total commitments	$437

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 amounted to $25 million in 2010, $27 million in 2009, and $26 million in 2008. Of these amounts, $20 million, $20 million, and $19 million for 2010, 2009, and 2008, respectively, relate to the rail car leases and are recoverable through the Company's Rate ECR.

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

	Minimum Lease Payments		
	Rail Cars	Vehicles & Other	Total
		(in millions)	
2011	$16	$ 4	$20
2012	15	2	17
2013	11	1	12
2014	6	1	7
2015	5	1	6
2016 and thereafter	7	1	8
Total *	$60	$10	$70

* 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 above rental commitments payments, the Company has potential obligations upon expiration of certain leases with respect to the residual value of the leased property. The Company's maximum obligations under these leases are $1 million in 2012, $39 million in 2013, $8 million in 2014, $5 million in 2015, and $4 million in 2016. Upon termination of the leases, the Company has the option to negotiate an extension, exercise its purchase option, or the property can be sold to a third party. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligations.

Guarantees

At December 31, 2010, 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 COMPENSATION

Stock Option Plan

Southern Company provides non-qualified stock options to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2010, there were 1,313 current and former employees of the Company participating in the stock option plan and there were 10 million shares of Southern Company common stock remaining available for awards under this plan and the Performance Share Plan discussed below. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the stock option plan. For certain stock option awards, a change in control will provide accelerated vesting.

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

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

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

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

	Shares Subject to Option	**Weighted Average Exercise Price**
Outstanding at December 31, 2009	8,749,474	$31.74
Granted	1,532,979	31.25
Exercised	(1,512,059)	27.76
Cancelled	(25,410)	31.33
Outstanding at December 31, 2010	**8,744,984**	**$ 32.35**
Exercisable at December 31, 2010	**5,920,732**	**$ 32.61**

The number of stock options vested, and expected to vest in the future, as of December 31, 2010 was not significantly different from the number of stock options outstanding at December 31, 2010 as stated above. As of December 31, 2010, the weighted average remaining contractual term for the options outstanding and options exercisable was approximately six years and five years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $52 million and $33 million, respectively.

As of December 31, 2010, there was $1 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 10 months.

For the years ended December 31, 2010, 2009, and 2008, total compensation cost for stock option awards recognized in income was $3 million, $4 million, and $3 million, respectively, with the related tax benefit also recognized in income of $1 million, $1 million, and $1 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, 2010, 2009, and 2008 was $12 million, $2 million, and $5 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $4 million, $1 million, and $2 million for the years ended December 31, 2010, 2009, and 2008, respectively.

Performance Share Plan

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

The fair value of performance share awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period. The Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. Expected volatility used in the model of 20.7% was based on historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate of 1.4% was based on the U.S. Treasury yield curve in effect at the time of grant that covers the performance period of the award units. The annualized dividend rate at the time of the grant was $1.75. During 2010, 166,725 performance share units were granted to the Company's employees with a weighted-average grant date fair value of $30.13. During 2010, 14,923 performance share units were forfeited by the Company's employees resulting in 151,802 unvested units outstanding at December 31, 2010.

For the year ended December 31, 2010, the Company's total compensation cost for performance share units recognized in income was $1 million, with the related tax benefit also recognized in income of $1 million. As of December 31, 2010, there was $3 million of total unrecognized compensation cost related to performance share award units that will be recognized over the next two years.

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' operating nuclear generating facilities. Additionally, the Company has policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $2.3 billion for losses in excess of the $500 million primary coverage. This excess insurance is also provided by NEIL.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. The Company purchases the maximum limit allowed by NEIL 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 $42 million.

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

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

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes. In the event of a loss, the amount of insurance available may not be adequate to cover property damage and other incurred expenses.

10. FAIR VALUE MEASUREMENTS

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

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

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

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

	Fair Value Measurements Using			
As of December 31, 2010:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Energy-related derivatives	$ -	$ 2	$ -	$ 2
Nuclear decommissioning trusts:[(a)]				
Domestic equity	347	59	-	406
U.S. Treasury and government agency securities	20	7	-	27
Corporate bonds	-	82	-	82
Mortgage and asset backed securities	-	30	-	30
Other	-	7	-	7
Cash equivalents and restricted cash	109	-	-	109
Total	$476	$187	$ -	$663
Liabilities:				
Energy-related derivatives	$ -	$ 40	$ -	$ 40

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

Valuation Methodologies

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

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

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

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

As of December 31, 2010:	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
	(in millions)			
Nuclear decommissioning trusts:				
Trust-owned life insurance	$ 86	None	Daily	15 days
Cash equivalents and restricted cash:				
Money market funds	109	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 through death proceeds, loans against the cash surrender value, and/or the cash surrender value, subject to legal restrictions. The amounts reported in the table 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 SEC 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, 2010 and 2009, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2010	**$6,187**	**$6,463**
2009	$6,182	$6,357

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

11. DERIVATIVES

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

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages fuel-hedging programs, implemented per the guidelines of the Alabama PSC, through the use of financial derivative contracts, and recently has started using financial options, which is expected to continue to mitigate price volatility.

To mitigate residual risks relative to movements in electricity prices, the Company may enter 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 which are mainly used to hedge anticipated purchases and sales and are initially deferred in OCI before being recognized in the statements of 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, 2010, 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:

Gas		
Net Purchased mmBtu*	**Longest Hedge Date**	**Longest Non-Hedge Date**
(in millions)		
34	2015	-

*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, 2011 are immaterial.

Interest Rate Derivatives

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

At December 31, 2010, the Company did not have any interest rate derivatives outstanding. Subsequent to December 31, 2010, the Company entered into forward-starting interest rate swaps to mitigate exposure to interest rate changes related to an anticipated debt issuance. The notional amount of the swaps totaled $200 million.

The estimated pre-tax gains that will be reclassified from OCI to interest expense for the next 12-month period ending December 31, 2011 is $1 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, 2010 and 2009, the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2010**	2009	**Balance Sheet Location**	**2010**	2009
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$1**	$1	Liabilities from risk management activities	**$31**	$34
	Other deferred charges and assets	**1**	-	Other deferred credits and liabilities	**9**	11
Total derivatives designated as hedging instruments for regulatory purposes		**$2**	$1		**$40**	$45
Derivatives designated as hedging instruments in cash flow hedges						
Interest rate derivatives:	Other current assets	**$ -**	$ -	Liabilities from risk management activities	**$ -**	$ 4
Total		**$2**	$1		**$40**	$49

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

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

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2010**	2009	**Balance Sheet Location**	**2010**	2009
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$(31)**	$(34)	Other current liabilities	**$1**	$1
	Other regulatory assets, deferred	**(9)**	(11)	Other regulatory liabilities, deferred	**1**	-
Total energy-related derivative gains (losses)		**$(40)**	$(45)		**$2**	$1

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

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)			Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
					Amount		
Derivative Category	**2010**	2009	2008	**Statements of Income Location**	**2010**	2009	2008
		(in millions)				*(in millions)*	
Interest rate derivatives	**$ -**	$(5)	$(11)	Interest expense, net of amounts capitalized	**$3**	$(12)	$(3)

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

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

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. 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, 2010, the fair value of derivative liabilities with contingent features was $6 million.

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

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

12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

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

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
		(in millions)	
March 2010	**$1,495**	**$399**	**$203**
June 2010	**1,462**	**389**	**190**
September 2010	**1,706**	**497**	**259**
December 2010	**1,313**	**204**	**55**
March 2009	$1,340	$299	$146
June 2009	1,366	349	177
September 2009	1,592	483	261
December 2009	1,231	189	86

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

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

	2010	2009	2008	2007	2006
Operating Revenues (in millions)	**$5,976**	$5,529	$6,077	$5,360	$5,015
Net Income after Dividends					
on Preferred and Preference Stock (in millions)	**$707**	$670	$616	$580	$518
Cash Dividends					
on Common Stock (in millions)	**$586**	$523	$491	$465	$441
Return on Average Common Equity (percent)	**13.31**	13.27	13.30	13.73	13.23
Total Assets (in millions)	**$17,994**	$17,524	$16,536	$15,747	$14,655
Gross Property Additions (in millions)	**$956**	$1,323	$1,533	$1,203	$961
Capitalization (in millions):					
Common stock equity	**$5,393**	$5,237	$4,854	$4,411	$4,032
Preference stock	**343**	343	343	343	147
Redeemable preferred stock	**342**	342	342	340	465
Long-term debt	**5,987**	6,082	5,605	4,750	4,148
Total (excluding amounts due within one year)	**$12,065**	$12,004	$11,144	$9,844	$8,792
Capitalization Ratios (percent):					
Common stock equity	**44.7**	43.6	43.6	44.8	45.9
Preference stock	**2.9**	2.9	3.1	3.5	1.7
Redeemable preferred stock	**2.8**	2.8	3.0	3.4	5.3
Long-term debt	**49.6**	50.7	50.3	48.3	47.1
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**1,235,128**	1,229,134	1,220,046	1,207,883	1,194,696
Commercial	**197,336**	198,642	211,119	216,830	214,723
Industrial	**5,770**	5,912	5,906	5,849	5,750
Other	**782**	780	775	772	766
Total	**1,439,016**	1,434,468	1,437,846	1,431,334	1,415,935
Employees (year-end)	**6,552**	6,842	6,997	6,980	6,796

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

	2010	2009	2008	2007	2006
Operating Revenues (in millions):					
Residential	**$2,283**	$1,962	$1,998	$1,834	$1,664
Commercial	**1,535**	1,430	1,459	1,314	1,172
Industrial	**1,231**	1,080	1,381	1,238	1,140
Other	**27**	25	24	21	20
Total retail	**5,076**	4,497	4,862	4,407	3,996
Wholesale - non-affiliates	**465**	620	712	627	635
Wholesale - affiliates	**236**	237	308	144	215
Total revenues from sales of electricity	**5,777**	5,354	5,882	5,178	4,846
Other revenues	**199**	175	195	182	169
Total	**$5,976**	$5,529	$6,077	$5,360	$5,015
Kilowatt-Hour Sales (in millions):					
Residential	**20,417**	18,071	18,380	18,874	18,633
Commercial	**14,719**	14,186	14,551	14,761	14,355
Industrial	**20,622**	18,555	22,075	22,806	23,187
Other	**216**	218	201	201	199
Total retail	**55,974**	51,030	55,207	56,642	56,374
Wholesale - non-affiliates	**8,655**	14,317	15,204	15,769	15,979
Wholesale - affiliates	**6,074**	6,473	5,256	3,241	5,145
Total	**70,703**	71,820	75,667	75,652	77,498
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**11.18**	10.86	10.87	9.71	8.93
Commercial	**10.43**	10.08	10.03	8.90	8.17
Industrial	**5.97**	5.82	6.26	5.43	4.92
Total retail	**9.07**	8.81	8.81	7.78	7.09
Wholesale	**4.76**	4.12	4.99	4.06	4.03
Total sales	**8.17**	7.45	7.77	6.84	6.25
Residential Average Annual Kilowatt-Hour Use Per Customer	**16,570**	14,716	15,162	15,696	15,663
Residential Average Annual Revenue Per Customer	**$1,853**	$1,597	$1,648	$1,525	$1,399
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**12,222**	12,222	12,222	12,222	12,222
Maximum Peak-Hour Demand (megawatts):					
Winter	**11,349**	10,701	10,747	10,144	10,309
Summer	**11,488**	10,870	11,518	12,211	11,744
Annual Load Factor (percent)	**62.6**	59.8	60.9	59.4	61.8
Plant Availability (percent):					
Fossil-steam	**92.9**	88.5	90.1	88.2	89.6
Nuclear	**88.4**	93.3	94.1	87.5	93.3
Source of Energy Supply (percent):					
Coal	**56.6**	53.4	58.5	60.9	60.2
Nuclear	**17.7**	18.6	17.8	16.5	17.4
Hydro	**5.0**	7.9	2.9	1.8	3.8
Gas	**14.0**	11.8	9.2	8.7	7.6
Purchased power -					
From non-affiliates	**1.6**	2.0	2.9	1.8	2.1
From affiliates	**5.1**	6.3	8.7	10.3	8.9
Total	**100.0**	100.0	100.0	100.0	100.0

DIRECTORS AND OFFICERS
Alabama Power Company 2010 Annual Report

Directors

Whit Armstrong
Chairman,
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

Thomas A. Fanning [1]
Chairman, President and CEO,
Southern Company

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 [2]
Former Chairman, President and CEO,
Southern Company

C. Dowd Ritter
Retired 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 [3]
Chairman,
First Tuskegee Bank

Officers

Charles D. McCrary
President and Chief Executive Officer

Art P. Beattie [4]
Executive Vice President, Chief Financial Officer and Treasurer

Mark A. Crosswhite [5]
Executive Vice President

Philip C. Raymond [6]
Executive Vice President, Chief Financial Officer and Treasurer

Steve R. Spencer
Executive Vice President

Zeke W. Smith[7]
Executive Vice President

Greg Barker [8]
Senior Vice President

Gordon G. Martin
Senior Vice President and General Counsel

Theodore J. McCullough [9]
Senior Vice President

Robert Holmes, Jr. [10]
Senior Vice President

Jerry L. Stewart [11]
Senior Vice President

Terry H. Waters [12]
Senior Vice President

Moses H. Feagin [13]
Vice President and Comptroller

Anita Allcorn-Walker[14]
Vice President and Comptroller

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

Kathleen S. King
Vice President, Chief Information Officer

Matthew W. Bowden
Vice President

Kenneth E. Coleman
Vice President, Southern Division

Mark S. Crews [15]
Vice President, Western Division

Daniel K. Glover
Vice President

R. Myrk Harkins [16]
Vice President

John O. Hudson III [17]
Vice President

Richard O. Hutto[18]
Vice President Southeast Division

Marsha S. Johnson [19]
Vice President

William B. Johnson [20]
Vice President

Stacy R. Kilcoyne [21]
Vice President

Barbara J. Knight
Vice President,
Birmingham Division

Richard J. Mandes, Jr.
Vice President

Kenneth F. Novak [22]
Vice President

Leigh Davis-Perry
Vice President

Myrna J. Pittman
Vice President

Leslie L. Sanders
Vice President

R. Michael Saxon
Vice President, Mobile Division

Julia H. Segars
Vice President, Eastern Division

Nicholas C. Sellers
Vice President

Don A. Scivley [23]
Vice President

Donna D. Smith [24]
Vice President

Robert L. Weaver [25]
Vice President

Ronald Q. Patterson
Assistant Comptroller

Melissa K. Caen
Assistant Secretary and Assistant Treasurer

Ceila H. Shorts
Assistant Secretary

Kay I. Worley
Assistant Secretary

Christopher R. Blake [26]
Assistant Treasurer

Xia Liu [27, 28]
Assistant Treasurer

[1] **Elected 12/10**
[2] **Retired 12/10**
[3] **Deceased 12/10**
[4] **Resigned 8/10**
[5] **Resigned 12/10**
[6] **Elected 8/10**
[7] **Elected 11/10**
[8] **Elected 7/10**
[9] **Elected 6/10**
[10] **Retired 12/10**
[11] **Retired 10/10**
[12] **Retired 8/10**
[13] **Resigned 8/10**
[14] **Elected 8/10**
[15] **Elected 4/10**
[16] **Elected 4/10**
[17] **Elected 5/10**
[18] **Elected 4/10**
[19] **Retired 9/10**
[20] **Retired 7/10**
[21] **Elected 10/10**
[22] **Elected 9/10**
[23] **Elected 9/10**
[24] **Elected 1/11**
[25] **Elected 4/10**
[26] **Appointed 8/10**
[27] **Appointed 4/10**
[28] **Resigned 8/10**

CORPORATE INFORMATION
Alabama Power Company 2010 Annual Report

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

Profile
The Company 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 2010, retail energy sales accounted for 79 percent of the Company's total sales of 71 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 of Preferred and Preference Stock
BNY Mellon Shareowner Services
480 Washington Boulevard
Jersey City, NJ 07310-1900
(800) 554-7626
www.bnymellon.com/shareowner/equityaccess

Number of Preferred Shareholders of record as of December 31, 2010 was 1,402.

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

Alabama Power Company
600 North 18th Street
Birmingham, AL 35203
(205) 257-1000
www.alabamapower.com

Auditors
Deloitte & Touche LLP
417 North 20th Street
Suite 1000
Birmingham, AL 35203

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