ALABAMA POWER COMPA...

2012 ANNUAL REPORT

ALABAMA POWER

A SOUTHERN COMPANY

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Alabama Power Company 2012 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, 2012.

Charles D. McCrary
President and Chief Executive Officer

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

February 27, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
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 The Southern Company) as of December 31, 2012 and 2011, 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, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such financial statements (pages 30 to 78) present fairly, in all material respects, the financial position of Alabama Power Company as of December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Birmingham, Alabama
February 27, 2013

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 territory 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

The Company continues to focus on several key performance 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 customer satisfaction. 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 2012 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. The performance for 2012 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 2012 results compared to its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2012 Target Performance	2012 Actual Performance
Customer Satisfaction	**Top quartile in customer surveys**	**Top quartile**
Peak Season EFOR — fossil/hydro	**4.99% or less**	**0.75%**
Net Income After Dividends on Preferred and Preference Stock	**$701 million**	**$704 million**

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The performance achieved in 2012 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 2012 net income after dividends on preferred and preference stock of $704 million decreased $4 million (0.6%) from the prior year. The decrease was due to decreases in weather-related revenues due to milder weather in 2012 compared to 2011 and an increase in other operations and maintenance expenses. The factors decreasing net income were partially offset by increases in revenues associated with the elimination of a tax-related adjustment under the Company's rate structure effective in the fourth quarter 2011 and an increase in retail sales growth.

The Company's 2011 net income after dividends on preferred and preference stock of $708 million increased $1 million (0.1%) from the prior year. The increase was due to a reduction in other operations and maintenance expenses, an increase in revenues under rate certificated new plant environmental (Rate CNP Environmental) associated with the completion of construction projects related to environmental mandates, and an increase in industrial kilowatt-hour (KWH) sales. The factors increasing net income were partially offset by reductions in wholesale revenues from sales to non-affiliates, decreases in weather-related revenues due to closer to normal weather in 2011 compared to 2010, and a reduction in allowance for funds used during construction (AFUDC) equity.

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

	Amount	Increase (Decrease) from Prior Year	
	2012	**2012**	2011
		(in millions)	
Operating revenues	**$ 5,520**	**$ (182)**	$ (274)
Fuel	**1,503**	**(176)**	(172)
Purchased power	**255**	**(16)**	(9)
Other operations and maintenance	**1,287**	**25**	(156)
Depreciation and amortization	**639**	**2**	31
Taxes other than income taxes	**340**	**1**	7
Total operating expenses	**4,024**	**(164)**	(299)
Operating income	**1,496**	**(18)**	25
Allowance for equity funds used during construction	**19**	**(3)**	(14)
Interest income	**16**	**(2)**	1
Interest expense, net of amounts capitalized	**287**	**(12)**	(4)
Other income (expense), net	**(24)**	**6**	—
Income taxes	**477**	**(1)**	15
Net income	**743**	**(4)**	1
Dividends on preferred and preference stock	**39**	**—**	—
Net income after dividends on preferred and preference stock	**$ 704**	**$ (4)**	$ 1

Operating Revenues

Operating revenues for 2012 were $5.5 billion, reflecting a $182 million decrease from 2011. Details of operating revenues were as follows:

	Amount	
	2012	2011
	(in millions)	
Retail — prior year	**$ 4,972**	$ 5,076
Estimated change in —		
Rates and pricing	**69**	88
Sales growth (decline)	**61**	42
Weather	**(115)**	(147)
Fuel and other cost recovery	**(54)**	(87)
Retail — current year	**4,933**	4,972
Wholesale revenues —		
Non-affiliates	**277**	287
Affiliates	**111**	244
Total wholesale revenues	**388**	531
Other operating revenues	**199**	199
Total operating revenues	**$ 5,520**	$ 5,702
Percent change	**(3.2)%**	(4.6)%

Retail revenues in 2012 were $4.9 billion. These revenues decreased $39 million (0.8%) in 2012 and decreased $104 million (2.0%) in 2011, each as compared to the prior year. The decrease in 2012 was due to milder weather, a reduction in revenues under Rate CNP Environmental, and a reduction in fuel revenues when compared to 2011. The decreases were partially offset by increased revenues associated with the elimination of a tax-related adjustment under the Company's rate structure and weather adjusted sales growth due to higher demand. The decrease in 2011 was due to closer to normal weather in 2011 compared to 2010 and a reduction in fuel revenues. The decreases were partially offset by increased revenues associated with Rate CNP Environmental for the completion of construction projects related to environmental mandates and the elimination of a tax-related adjustment under the Company's rate structure. See FUTURE EARNINGS POTENTIAL – "PSC Matters" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information. See "Energy Sales" 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 – Energy Cost Recovery" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Energy Cost Recovery" for additional information.

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

	2012	2011	2010
		(in millions)	
Unit power sales —			
Capacity	**$ —**	$ —	$ 84
Energy	**—**	6	95
Total	**—**	6	179
Other power sales —			
Capacity and other	**143**	148	148
Energy	**134**	133	138
Total	**277**	281	286
Total non-affiliated	**$ 277**	$ 287	$ 465

Wholesale revenues from sales to non-affiliates will vary depending on the market prices of available wholesale energy compared to the cost of the Company's and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income.

In 2012, wholesale revenues from sales to non-affiliates decreased $10 million (3.5%) reflecting a $5 million decrease in revenue from energy sales and a $5 million decrease in capacity revenues. The price of energy decreased 5.2%, partially offset by a 1.8% increase in KWH sales. In 2011, wholesale revenues from sales to non-affiliates decreased $178 million (38.3%) reflecting a $94 million decrease in revenue from energy sales and an $84 million decrease in capacity revenues. These decreases were primarily due to the expiration of long-term unit power sales contracts in 2010. KWH sales decreased 46.9%, partially offset by a 15.3% increase in the price of energy. 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 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.

In 2012, wholesale revenues from sales to affiliates decreased $133 million (54.5%) primarily due to a $6 million decrease in capacity revenues and a $127 million decrease in energy sales. KWH sales decreased 45% and there was a 17.6% decrease in the price of energy. In 2011, wholesale revenues from sales to affiliates increased $8 million (3.4%). The change from prior year revenues was not material.

In 2012 and 2011, other operating revenues were $199 million. In 2011, the change from prior year revenues was not material.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2012 and the percent change by year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2012	**2012**	2011	**2012**	2011
	(in billions)				
Residential	**17.6**	**(5.6)%**	(8.7)%	**2.6%**	0.6%
Commercial	**14.0**	**(1.5)**	(3.7)	**0.6**	(0.6)
Industrial	**22.1**	**2.3**	5.1	**2.3**	5.1
Other	**0.2**	**—**	(0.9)	**—**	(0.9)
Total retail	**53.9**	**(1.4)**	(2.3)	**1.9%**	2.0%
Wholesale —					
Non-affiliates	**4.6**	**0.6**	(46.9)		
Affiliates	**3.9**	**(44.9)**	15.3		
Total wholesale	**8.5**	**(26.9)**	(21.3)		
Total energy sales	**62.4**	**(5.9)%**	(6.2)%		

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 2012 were 1.4% less than in 2011. Residential and commercial sales decreased 5.6% and 1.5%, respectively, due primarily to milder weather in 2012. Weather-adjusted residential sales increased 2.6%, primarily due to an increase in customer demand. Industrial sales increased 2.3% in 2012 as a result of increased customer demand, primarily in the pipelines, primary metals, chemicals, and automotive and plastics sectors, due to a recovering economy, partially offset by decreases in the textiles, and stone, clay and glass sectors.

Retail energy sales in 2011 were 2.3% less than in 2010. Residential and commercial sales decreased 8.7% and 3.7%, respectively, due primarily to closer to normal weather in 2011 compared to 2010. Industrial sales increased 5.1% in 2011 as a result of increased customer demand, primarily in the primary metals and chemicals sectors, due to a recovering economy.

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.

Details of the Company's generation and purchased power were as follows:

	2012	2011	2010
Total generation *(billions of KWHs)*	**59.9**	64.8	69.2
Total purchased power *(billions of KWHs)*	**5.4**	4.7	5.0
Sources of generation *(percent)* —			
Coal	**53**	56	61
Nuclear	**25**	22	19
Gas	**18**	17	15
Hydro	**4**	5	5
Cost of fuel, generated *(cents per net KWH)* —			
Coal	**3.30**	3.16	3.02
Nuclear	**0.80**	0.66	0.60
Gas	**3.06**	3.92	4.47
Average cost of fuel, generated *(cents per net KWH)**	**2.61**	2.70	2.76
Average cost of purchased power *(cents per net KWH)***	**4.86**	6.04	6.42

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

** Average cost of purchased power includes fuel purchased by the Company for tolling agreements where power is generated by the provider.

Fuel and purchased power expenses were $1.8 billion in 2012, a decrease of $192 million (9.8%) compared to 2011. The decrease was primarily due to a $143 million decrease related to lower KWHs generated due to milder weather in 2012 compared to 2011 and a $92 million decrease in the cost of natural gas and the average cost of purchased power, partially offset by increases in the cost of coal and nuclear fuel.

Fuel and purchased power expenses were $2.0 billion in 2011, a decrease of $181 million (8.5%) compared to 2010. The decrease was primarily due to a $108 million decrease related to lower KWHs generated as a result of closer to normal weather in 2011 compared to 2010, a reduction in unit power energy sales, and a $56 million decrease in the cost of natural gas and the average cost of purchased power, partially offset by increases in the cost of coal and nuclear fuel.

Fuel and purchased power energy transactions do not have a significant impact on earnings, since energy expenses are generally offset by energy revenues through the Company's Energy Cost Recovery Rate mechanism (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 – Energy Cost Recovery" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Energy Cost Recovery" for additional information.

From an overall global market perspective, coal prices decreased from levels experienced in 2011 due to lower demand. In the U.S., this decrease was due primarily to relatively lower domestic natural gas prices that contributed to displacement of coal generation by natural gas-fueled generating units. Lower domestic natural gas prices in 2012 were driven by continued robust supplies, including production from shale gas, and only modest increases in overall U.S. consumption.

Uranium prices began to decrease during the second half of 2012 as extended reactor shutdowns in Europe and Asia caused global demand for uranium to drop below the level of previous years, while production increased. Changes in the cost of fuel for nuclear generation tend to lag behind changes in uranium market prices. Even though uranium prices decreased slightly during 2012, the cost of fuel for nuclear generation increased in 2012, reflecting the higher uranium prices from previous years when the uranium was purchased.

Fuel

Fuel expenses were $1.5 billion in 2012, a decrease of $176 million (10.5%) compared to 2011. This decrease was primarily due to a 21.9% decrease in the average cost of KWHs generated by natural gas, which excludes fuel associated with tolling agreements, and a 13.7% decrease in KWHs generated by coal, partially offset by 20.2% and 4.6% increases in the average cost of KWHs generated by nuclear fuel and coal, respectively. Fuel expenses were $1.7 billion in 2011, a decrease of $172 million (9.3%) compared to 2010. This decrease was primarily due to a 13.1% decrease in KWHs generated by coal and a 12.4% decrease in the average cost of KWHs generated by natural gas, which excludes fuel associated with tolling agreements, partially offset by a 10.7% increase in the average cost of KWHs generated by nuclear.

Purchased Power - Non-Affiliates

In 2012 and 2011, purchased power from non-affiliates was $73 million. In 2011, purchased power from non-affiliates increased $1 million. The increase over prior year costs was not material.

Energy purchases from non-affiliates will vary depending on the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation.

Purchased Power - Affiliates

Purchased power from affiliates was $182 million in 2012, a decrease of $16 million (8.1%) compared to 2011. This decrease was primarily due to a 9.6% decrease in the average cost per KWH, partially offset by a 1.7% increase in the amount of energy purchased. Purchased power from affiliates was $198 million in 2011, a decrease of $10 million (4.8%) compared to 2010. This decrease was primarily due to an 18.9% decrease in the average cost per KWH, partially offset by a 6.9% increase in the amount of energy purchased.

Energy purchases from affiliates will vary depending on demand for energy and the availability and cost of generating resources at each company within the Southern Company system. These purchases are made in accordance with the IIC or other contractual agreements, as approved by the FERC.

Other Operations and Maintenance Expenses

In 2012, other operations and maintenance expenses increased $25 million (2.0%) as compared to the prior year. Administrative and general expenses increased $45 million primarily related to pension and other benefit-related expenses and injuries and damages expenses. Nuclear production expenses increased $23 million primarily related to the amortization of nuclear outage expenses of $35 million due to a change in the nuclear maintenance outage accounting process associated with routine refueling activities, as approved by the Alabama PSC in 2010. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Nuclear Outage Accounting Order" herein for additional information. The increase in nuclear production expenses was partially offset by a decrease in operations costs related to labor expense. Other power generation expenses increased $6 million primarily related to scheduled outage costs and maintenance costs related to increases in labor and materials expenses. Transmission and distribution expenses decreased $32 million primarily related to a reduction in accruals to the natural disaster reserve (NDR). Steam production expenses decreased $22 million primarily related to a change in scheduled outage maintenance.

In 2011, other operations and maintenance expenses decreased $156 million (11.0%) as compared to the prior year. Transmission and distribution expenses decreased $79 million primarily related to vegetation management, reliability projects, and a reduction in accruals to the NDR. Nuclear production expenses decreased $33 million primarily related to the change in the nuclear maintenance outage accounting process in 2010 which resulted in no nuclear maintenance outage expenses being recognized in 2011, reducing nuclear production expense by approximately $50 million compared to the prior year. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Nuclear Outage Accounting Order" herein for additional information. The decrease in nuclear production expenses was partially offset by an increase in operations costs related to labor expense. Administrative and general expenses decreased $28 million primarily related to injuries and damages expenses, affiliated service companies' expenses, and property insurance.

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

Depreciation and Amortization

Depreciation and amortization increased $2 million (0.3%) in 2012 and $31 million (5.1%) in 2011, each as compared to the prior year. The increase in 2012 was not material. The increase in 2011 was primarily due to additions to property, plant, and equipment related to environmental mandates (which are 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.

In 2011, the Company submitted a depreciation study to FERC and received authorization to use the recommended rates beginning in January 2012.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $1 million (0.3%) in 2012 and $7 million (2.1%) in 2011, each as compared to the prior year. The increase in 2012 was not material. The increase in 2011 was primarily due to increases in state and municipal public utility license tax bases and an increase in local use tax.

Allowance for Funds Used During Construction Equity

AFUDC equity decreased $3 million (13.6%) in 2012 as compared to the prior year primarily due to a decrease in capital expenditures associated with general plant projects and nuclear-related fuel and facilities. These decreases were primarily offset by increases in transmission and hydro generating facilities. AFUDC equity decreased $14 million (38.9%) in 2011 as compared to the prior year primarily due to the completion of construction projects related to environmental mandates at Plants Barry, Gaston, and Miller. 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 decreased $12 million (4.0%) in 2012 and $4 million (1.3%) in 2011, each as compared to the prior year. The decrease in 2012 was primarily due to a decrease in interest on long term debt. The decrease in 2011 was not material.

Other Income (Expense), Net

Other income (expense), net increased $6 million (20.0%) in 2012 as compared to the prior year primarily due to an increase in non-operating income of $3 million, an increase in sales of property of $2 million, and a decrease in other deductions of $1 million. Other income (expense), net remained flat in 2011 as compared to the prior year.

Income Taxes

Income taxes decreased $1 million (0.2%) in 2012 and increased $15 million (3.2%) in 2011, each as compared to the prior year. The decrease in 2012 was not material. The increase in 2011 was primarily due to higher pre-tax income, an increase in the tax expense associated with a decrease in AFUDC equity, and prior year tax return actualization.

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 territory. 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 federal and state 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 differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Environmental Matters" for additional information.

New Source Review Actions

In 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including the Company, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by the Company and three coal-fired generating facilities operated by Georgia Power Company (Georgia Power). The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The case against Georgia Power was administratively closed in 2001 and has not been reopened. After the Company was dismissed from the original action, the EPA filed a separate action in 2001 against the Company in the U.S. District Court for the Northern District of Alabama.

In 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree, resolving claims relating to the alleged NSR violations at Plant Miller. In 2010, the EPA dismissed five of its eight remaining claims against the Company, leaving only three claims, including one relating to a unit co-owned by Mississippi Power Company (Mississippi Power). In March 2011, the U.S. District Court for the Northern District of Alabama granted the Company summary judgment on all remaining claims and dismissed the case with prejudice. That judgment is on appeal to the U.S. Court of Appeals for the Eleventh Circuit. On February 23, 2012, the EPA filed a motion in the U.S. District Court for the Northern District of Alabama seeking vacatur of the judgment and recusal of the judge in the case involving the Company.

The Company believes it complied with applicable laws and regulations 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, depending on the date of the alleged violation. An adverse outcome could require substantial 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.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit 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 allege 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 (including Southern Company) 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. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. In May 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the plaintiffs' amended complaint. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. The Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2012, the Company had invested approximately $3.0 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $62 million, $34 million, and $130 million for 2012, 2011, and 2010, respectively. The Company expects that base level capital expenditures to comply with existing statutes and regulations, including capital expenditures and compliance costs associated with the EPA's final Mercury and Air Toxics Standards (MATS) rule, will be a total of approximately $1.0 billion from 2013 through 2015, with annual totals of approximately $195 million, $424 million, and $411 million for 2013, 2014, and 2015, respectively.

The Company continues to monitor the development of the EPA's proposed water and coal combustion byproducts rules and to evaluate compliance options. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein for the Company's anticipated incremental compliance costs related to the proposed water and coal combustion byproducts rules for 2013 through 2015. The ultimate capital expenditures and compliance costs with respect to these proposed rules, including additional expenditures required after 2015, will be dependent on the requirements of the final rules and regulations adopted by the EPA and the outcome of any legal challenges to these rules. See "Water Quality" and "Coal Combustion Byproducts" herein for additional information.

The Company's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations and regulations relating to global climate change that are promulgated, including the proposed environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time.

Southern Electric Generating Company (SEGCO), a subsidiary of the Company, is jointly owned with Georgia Power. As part of its environmental compliance strategy, SEGCO plans to add natural gas as the primary fuel source for its generating units in 2015. The capacity of SEGCO's units is sold equally to the Company and Georgia Power through a power purchase agreement (PPA). The impact of SEGCO's ultimate compliance strategy on such PPA costs cannot be determined at this time; however, if such costs cannot continue to be recovered through retail rates, they could have a material financial impact on the Company's financial statements. See Note 4 to the Company's financial statements for additional information.

Compliance with any new federal or state legislation or regulations relating to air quality, water, coal combustion byproducts, global climate change, 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. Since 1990, the Company has spent approximately $2.7 billion in reducing and monitoring emissions pursuant to the Clean Air Act. 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. In 2008, the EPA adopted a more stringent eight-hour ozone National Ambient Air Quality Standard, which it began to implement in September 2011. On May 21, 2012, the EPA published its final determination of nonattainment areas based on the 2008 eight-hour ozone air quality standards. No areas within the Company's service territory were determined to be in nonattainment of this standard.

The EPA regulates fine particulate matter concentrations on an annual and 24-hour average basis. All areas within the Company's service territory have achieved attainment with the 1997 and 2006 particulate matter National Ambient Air Quality Standards and, in January 2013, the EPA officially redesignated the Birmingham area as attainment under both the annual and 24-hour standards. On January 15, 2013, the EPA published a final rule that increases the stringency of the annual fine particulate matter standard. The new standard could result in the designation of new nonattainment areas within the Company's service territory.

Final revisions to the National Ambient Air Quality Standard for sulfur dioxide (SO_2), including the establishment of a new one-hour standard, became effective in 2010. The EPA plans to issue area designations under this new standard in June 2013, and areas within the Company's service territory could ultimately be designated as nonattainment. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

Revisions to the National Ambient Air Quality Standard for nitrogen dioxide (NO_2), which established a new one-hour standard, became effective in 2010. On February 29, 2012, the new NO_2 standard became effective. The EPA designated the entire country as "unclassifiable/attainment" under the new standard, with no nonattainment areas designated. However, the new NO_2 standard could result in significant additional compliance and operational costs for units that require new source permitting.

In 2008, the EPA approved a revision to Alabama's State Implementation Plan (SIP) requirements related to opacity, which granted some flexibility to affected sources while requiring compliance with Alabama's stringent opacity limits through use of continuous opacity monitoring system data. In April 2011, the EPA attempted to rescind its previous approval of the Alabama SIP revision. This decision impacts facilities operated by the Company, including units co-owned by Mississippi Power. The Company filed an appeal of that decision with the U.S. Court of Appeals for the Eleventh Circuit. The EPA's rescission has affected unit availability and increased maintenance and compliance costs. Unless the court resolves the Company's appeal in its favor, the EPA's rescission will continue to affect the Company's operations.

The Company's service territory is subject to the requirements of the Clean Air Interstate Rule (CAIR), which calls for phased reductions in SO_2 and nitrogen oxide (NO_x) emissions from power plants in 28 eastern states. In 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued decisions invalidating CAIR, but left CAIR compliance requirements in place while the EPA developed a new rule. In August 2011, the EPA adopted the Cross State Air Pollution Rule (CSAPR) to replace CAIR effective January 1, 2012. However, in December 2011, the U. S. Court of Appeals for the District of Columbia Circuit stayed the rule and, on August 21, 2012, vacated CSAPR in its entirety and directed the EPA to continue to administer CAIR pending the EPA's development of a valid replacement. On January 24, 2013, the U.S. Court of Appeals for the District of Columbia Circuit denied requests by the EPA and other parties for rehearing.

The EPA finalized the Clean Air Visibility Rule (CAVR) in 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. In 2005, the EPA determined that compliance with CAIR satisfies BART obligations under CAVR, but, on June 7, 2012, the EPA issued a final rule replacing CAIR with CSAPR as an alternative means of satisfying BART obligations. The vacatur of CSAPR creates additional uncertainty with respect to whether additional controls may be required for CAVR and BART compliance.

On February 16, 2012, the EPA published the final MATS rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015, unless a one-year compliance extension is granted by the state or local air permitting agency.

Numerous petitions for administrative reconsideration of the MATS rule, including a petition by the Company, have been filed with the EPA. On November 30, 2012, the EPA proposed a reconsideration of certain new source and startup/shutdown issues. The EPA plans to complete its reconsideration rulemaking by March 2013. Challenges to the final rule have also been filed in the U.S. District Court for the District of Columbia by numerous states, environmental organizations, industry groups, and others.

On August 29, 2012, the EPA published proposed revisions to the New Source Performance Standard (NSPS) for Stationary Combustion Turbines (CTs). If finalized as proposed, the revisions would apply the NSPS to all new, reconstructed, and modified CTs (including CTs at combined cycle units), during all periods of operation, including startup and shutdown, and alter the criteria for determining when an existing CT has been reconstructed.

On February 12, 2013, the EPA proposed a rule that would require certain states to revise the provisions of their SIPs relating to the regulation of excess emissions at industrial facilities, including fossil-fuel fired generating facilities, during periods of startup, shut-down, or malfunction (SSM). The EPA proposes a determination that the SSM provisions in the SIPs for 36 states, including Alabama, do not meet the requirements of the Clean Air Act and must be revised within 18 months of the date on which the EPA publishes the final rule. If finalized as proposed, this new requirement could result in significant additional compliance and operational costs.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the existing and new environmental requirements discussed above. As part of this strategy, the Company has developed a compliance plan for the MATS rule which includes the construction of baghouses to provide an additional level of control on the emissions of mercury and particulates from certain generating units, the use of additives or other injection technology, and the use of existing or additional natural gas capability. Additionally, certain transmission system upgrades may be required. SEGCO, jointly owned by the Company and Georgia Power, plans to add natural gas capability.

The impacts of the eight-hour ozone, fine particulate matter, SO_2 and NO_2 standards, CAIR and any future replacement rule, CAVR, the MATS rule, the NSPS for CTs, and the SSM rule on the Company cannot be determined at this time and will depend on the specific provisions of recently finalized and future rules, the resolution of pending and future legal challenges, and the development and implementation of rules at the state level. These 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.

Water Quality

In April 2011, the EPA published a proposed rule that establishes standards for reducing effects on fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. The rule also addresses cooling water intake structures for new units at existing facilities. Compliance with the proposed rule could require changes to existing cooling water intake structures at certain of the Company's generating facilities, and new generating units constructed at existing plants would be required to install closed cycle cooling towers. The EPA has entered into an amended settlement agreement to extend the deadline for issuing a final rule until June 27, 2013. If finalized as proposed, some of the Company's facilities may be subject to significant additional capital expenditures and compliance costs 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. The ultimate outcome of this rulemaking will depend on the final rule and the outcome of any legal challenges and cannot be determined at this time.

The EPA has announced its determination that revision of the current effluent guidelines for steam electric power plants is warranted and has stated that it intends to propose such revisions by April 2013 and finalize the revisions by May 2014. New advanced wastewater treatment requirements are expected and may result in the installation of additional controls on certain of the Company's facilities, which could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. The impact of the revised guidelines will depend on the specific technology requirements of the final rule and, therefore, cannot be determined at this time. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" for additional information regarding estimated compliance costs for 2013 through 2015.

Coal Combustion Byproducts

The Company currently operates six electric generating plants with on-site coal combustion byproducts 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. Historically, individual states have regulated coal combustion byproducts and the State of Alabama has its 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 continues to evaluate the regulatory program for coal combustion byproducts, including coal ash and gypsum, under federal solid and hazardous waste laws. In 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. Environmental groups and other parties have filed lawsuits in the U.S. District Court for the District of Columbia seeking to require the EPA to complete its rulemaking process and issue final regulations pertaining to the regulation of coal combustion byproducts.

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. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" for additional information regarding estimated compliance costs for 2013 through 2015.

Global Climate Issues

The EPA currently regulates greenhouse gases under the Prevention of Significant Deterioration and Title V operating permit programs of the Clean Air Act. In addition, over the past several years, the U.S. Congress has considered many proposals to reduce greenhouse gas emissions, mandate renewable or clean energy, and impose energy efficiency standards. Such proposals are expected to continue to be considered by the U.S. Congress. International climate change negotiations under the United Nations Framework Convention on Climate Change are also continuing.

On April 13, 2012, the EPA published proposed regulations to establish standards of performance for greenhouse gas emissions from new fossil fuel steam electric generating units. The EPA has also announced plans to develop federal guidelines for states to establish greenhouse gas emissions performance standards for existing sources. The impact of this rulemaking will depend on the scope and specific requirements of the final rule and the outcome of any legal challenges and, therefore, cannot be determined at this time.

Although the outcome of federal, state, and international initiatives cannot be determined at this time, additional restrictions on the Company's greenhouse gas emissions or requirements relating to renewable energy or energy efficiency at the federal or state level could result in significant additional compliance costs, including 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.

The EPA's greenhouse gas reporting rule requires annual reporting of carbon dioxide equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company reported 2011 greenhouse gas emissions of approximately 42 million metric tons of carbon dioxide equivalent. The preliminary estimate of the Company's 2012 greenhouse gas emissions on the same basis is approximately 38 million metric tons of carbon dioxide equivalent. The level of greenhouse gas emissions from year to year will depend 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.

FERC Matters

In 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 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 annual licenses for the Coosa River developments and the Warrior River developments in 2007. These annual licenses are automatically renewed each year 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. Though the Coosa application remains pending before FERC, in 2010, the FERC issued a new 30 year license to the Company for the Warrior River developments. In 2010, the Smith Lake Improvement and Stakeholders' Association filed a request for rehearing of the FERC order granting the new Warrior license. On November 15, 2012, the FERC denied the Smith Lake Improvement and Stakeholders' Association's request for rehearing. On December 17, 2012, the Smith Lake Improvement and Stakeholders' Association filed for rehearing of the November 15, 2012 order and on January 16, 2013, the FERC denied the request.

In 2006, the Company initiated the process of developing an application to relicense the Martin Dam Project located on the Tallapoosa River. The current Martin license will expire on June 8, 2013. In June 2011, the Company filed an application with the FERC to relicense the Martin Dam Project.

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 no later than August 31, 2013.

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

In July 2011, the Alabama PSC issued an order to eliminate a tax-related adjustment under the Company's rate structure effective with October 2011 billings. The elimination of this adjustment resulted in additional revenues of approximately $31 million for 2011. In accordance with the order, the Company made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to such additional 2011 revenues. The NDR was impacted as a result of operations and maintenance expenses incurred in connection with the April 2011 storms in Alabama. See "Natural Disaster Reserve" below for additional information. The elimination of this adjustment resulted in additional revenues of approximately $106 million for 2012.

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 (ROE) is projected to be between 13.0% and 14.5%. If the Company's actual retail ROE 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 ROE fall below the allowed equity return range.

In 2011 and 2012, retail rates under Rate RSE remained unchanged from 2010. On November 30, 2012, the Company made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2013; projected earnings were within the specified return range, and, therefore, retail rates under Rate RSE remained unchanged for 2013. Under the terms of Rate RSE, the maximum possible increase for 2014 is 5.00%. However, the Company is working with the Alabama PSC to develop a plan that will potentially preclude the need for a Rate RSE increase in 2014. The ultimate outcome of this matter cannot be determined at this time.

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 under rate certificated new plant (Rate CNP). The Company may also recover retail costs associated with certificated PPAs under rate certificated new plant (Rate CNP PPA). Effective April 2011, Rate CNP PPA was reduced by approximately $5 million annually. On March 6, 2012, the Alabama PSC issued a consent order that the Company leave in effect the current Rate CNP PPA factor for billings for the period April 1, 2012 through March 31, 2013. It is anticipated that no adjustment will be made to Rate CNP PPA in 2013. As of December 31, 2012, the Company had an under recovered certificated PPA balance of $9 million, $7 million of which is included in deferred under recovered regulatory clause revenues and $2 million of which is included in under recovered regulatory clause revenues in the balance sheet.

On September 17, 2012, the Alabama PSC approved and certificated a PPA for the purchase of approximately 200 megawatts (MWs) of the approximately 400 MWs of energy from wind-powered generating facilities and all associated environmental attributes, including renewable energy credits. The terms of this PPA and a previously approved and certificated PPA permit the Company to use the energy and retire the associated environmental attributes in service of its customers or to sell environmental attributes, separately or bundled with energy, to third parties. Approximately 200 MWs of energy from wind-powered generating facilities was operational in December 2012.

Rate CNP Environmental also allows for the recovery of the Company's retail costs associated with environmental laws, regulations, or other such mandates. Rate CNP Environmental 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. There was no adjustment to Rate CNP Environmental to recover environmental costs in 2011 or 2012. On November 26, 2012, the Company submitted calculations associated with its cost of complying with environmental mandates, as provided under Rate CNP Environmental. The filing reflected a projected unrecovered retail revenue requirement for environmental compliance of less than $1 million, which is to be recovered in the billing months of January 2013 through December 2013. On December 4, 2012, the Alabama PSC issued a consent order that the Company leave in effect for 2013 the factors associated with the Company's environmental compliance costs for the year 2012. Any unrecovered amounts associated with 2013 will be reflected in the 2014 filing. As of December 31, 2012, the Company had an under recovered environmental clause balance of $21 million which is included in under recovered regulatory clause revenues in the balance sheet.

Environmental Accounting Order

Proposed and final environmental regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions. In September 2011, the Alabama PSC approved an order allowing for the establishment of a regulatory asset to record the unrecovered investment costs associated with any such decisions, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure. These costs would be amortized over the affected unit's remaining useful life, as established prior to the decision regarding early retirement. See "Environmental Matters – Environmental Statutes and Regulations" herein for additional information regarding environmental regulations.

Compliance and Pension Cost Accounting Order

On November 6, 2012, the Alabama PSC approved an accounting order for certain compliance-related operation and maintenance expenditures for the years 2013 through 2017, as well as the incremental increase in operation expense related to pension cost for 2013. Under the accounting order, expenses from January 2013 through December 2017 related to compliance with standards addressing Critical Infrastructure Protection issued by the North American Electric Reliability Corporation and cyber security requirements issued by the Nuclear Regulatory Commission (NRC) will be deferred to a regulatory asset account and amortized over a three-year period beginning in January 2015. Expenses from January 2013 through December 2017 related to compliance with NRC guidance addressing the readiness at nuclear facilities within the U.S., as prompted by the earthquake and tsunami that struck Japan in March 2011, also will be deferred as a regulatory asset and recovered over the same amortization period. The compliance-related expenses to be afforded regulatory asset treatment over the five-year period are currently estimated to be approximately $43 million. See "Other Matters" herein for information regarding the NRC's guidance issued as a result of the earthquake and tsunami that struck Japan in 2011. In addition, the accounting order authorizes the Company to defer an incremental increase in its pension cost for 2013. That increased pension cost is estimated to be approximately $17 million. During 2013, the actual incremental increase will be deferred to a regulatory asset account and will be amortized over a three-year period beginning in January 2015. Pursuant to the accounting order, the Company has the ability to accelerate the amortization of the regulatory assets.

Energy Cost Recovery

The Company has established energy 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. On December 4, 2012, the Alabama PSC issued a consent order that the Company leave in effect the energy cost recovery rates which began in April 2011 for 2013. Therefore, the Rate ECR factor as of January 1, 2013 remained at 2.681 cents per KWH. Effective with billings beginning in January 2014, the Rate ECR factor will be 5.910 cents per KWH, absent a further order from the Alabama PSC.

As of December 31, 2012 and 2011, the Company had under recovered fuel balances of approximately $4 million and $31 million, respectively, which are included in deferred under recovered regulatory clause revenues in the balance sheets. This classification is 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 recovery of the 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 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 the authority, based on an order from the Alabama PSC, to accrue certain additional amounts as circumstances warrant. The order 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.

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.

During the first half of 2011, multiple storms caused varying degrees of damage to the Company's transmission and distribution facilities. The most significant storms occurred in April 2011, causing over 400,000 of the Company's 1.4 million customers to be without electrical service. The cost of repairing the damage to facilities and restoring electrical service to customers as a result of these storms was $42 million for operations and maintenance expenses and $161 million for capital-related expenditures.

In accordance with the order that was issued by the Alabama PSC in July 2011 to eliminate a tax-related adjustment under the Company's rate structure that resulted in additional revenues, the Company made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to the additional 2011 revenues, which were approximately $31 million.

The accumulated balances in the NDR for the years ended December 31, 2012 and December 31, 2011 were approximately $103 million and $110 million, respectively. Any accruals to the NDR are included in the balance sheets under other regulatory liabilities, deferred and are reflected as other operations and maintenance expenses in the statements of income.

Nuclear Outage Accounting Order

In 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 at Plant Farley during the 18-month cycle for the outages. In accordance with the 2010 order, nuclear outage expenses are deferred when the charges actually occur and then amortized over the subsequent 18-month period.

The initial result of implementation of the accounting order was that no nuclear maintenance outage expenses were recognized from January 2011 through December 2011, which decreased nuclear outage operations and maintenance expenses in 2011 from 2010 by approximately $50 million. During the fall of 2011, approximately $38 million of actual nuclear outage expenses associated with one unit at Plant Farley was deferred to a regulatory asset account; beginning in January 2012, these deferred costs are being amortized to nuclear operations and maintenance expenses over an 18-month period. During the spring of 2012, approximately $31 million of actual nuclear outage expenses associated with the second unit at Plant Farley was deferred to a regulatory asset account; beginning in July 2012, these deferred costs are being 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 pursuant to the existing order.

Income Tax Matters

Bonus Depreciation

In 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (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 production-period projects placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term production-period projects to be placed in service in 2013), which will have a positive impact on the future cash flows of the Company through 2013.

On January 2, 2013, the American Taxpayer Relief Act of 2012 (ATRA) was signed into law. The ATRA retroactively extended several tax credits through 2013 and extended 50% bonus depreciation for property to be placed in service in 2013 (and for certain long-term production-period projects to be placed in service in 2014). The extension of 50% bonus depreciation will have a positive impact on the future cash flows of the Company through 2014.

Consequently, the Company's positive cash flow benefit is estimated to be between $110 million and $120 million in 2013.

Other Matters

In accordance with accounting standards related to employers' accounting for pensions, the Company recorded pension costs of $6 million in 2012 and recorded non-cash pre-tax pension income of $21 million and $19 million in 2011 and 2010, respectively. Postretirement benefit costs for the Company were $10 million, $11 million, and $14 million in 2012, 2011, and 2010, 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 air quality and water standards, has increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by carbon dioxide and other emissions, coal combustion byproducts, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, 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 or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

In March 2011, a major earthquake and tsunami struck Japan and caused substantial damage to the nuclear generating units at the Fukushima Daiichi generating plant. The events in Japan have created uncertainties that may affect future costs for operating nuclear plants. Specifically, the NRC is performing additional operational and safety reviews of nuclear facilities in the U.S., which could potentially impact future operations and capital requirements. On March 12, 2012, the NRC issued three orders and a request for information based on the July 2011 NRC task force report recommendations that included, among other items, additional mitigation strategies for beyond-design-basis events, enhanced spent fuel pool instrumentation capabilities, hardened vents for certain classes of containment structures, site specific evaluations for seismic and flooding hazards, and various plant evaluations to ensure adequate coping capabilities during station blackout and other conditions. On August 29, 2012, the NRC staff issued the final interim staff guidance document, which offers acceptable approaches to meeting the requirements of the NRC's orders before the December 31, 2016 compliance deadline. The interim staff guidance is not mandatory, but licensees would be required to obtain NRC approval for taking an approach other than as outlined in the interim staff guidance. The final form and the resulting impact of any changes to safety requirements for nuclear reactors will be dependent on further review and action by the NRC. See "PSC Matters – Compliance and Pension Cost Accounting Order" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Compliance and Pension Cost Accounting Order" for additional information on the Company's PSC approved accounting order, which allows the deferral of certain compliance-related operations and maintenance expenditures related to compliance with the NRC guidance.

See RISK FACTORS of the Company in Item 1A of the Form 10-K for a discussion of certain risks associated with the operation of nuclear generating units, including potential impacts that could result from a major incident at a nuclear facility anywhere in the world. The ultimate outcome of these events cannot be determined at this time.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with generally accepted accounting principles (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. 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 any requirement to refund these regulatory 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 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.

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, healthcare 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 (discount rate, salaries, or long-term return on plan assets) would result in a $7 million or less change in total annual benefit expense and a $96 million or less change in projected obligations.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2012. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to comply with environmental regulations and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2013 through 2015, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Projected capital expenditures in that period include investments to add environmental equipment for existing generating units and to expand and improve transmission and distribution facilities. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt and equity issuances. 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," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan and the nuclear decommissioning trust funds increased in value as of December 31, 2012 as compared to December 31, 2011. No contributions to the qualified pension plan were made for the year ended December 31, 2012. 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 totaled $1.4 billion for 2012, a decrease of $672 million as compared to 2011. The decrease in cash provided from operating activities was primarily due to an increase in fossil fuel stock, a decrease in deferred income taxes, and the timing of income tax payments and refunds associated with bonus depreciation. Net cash provided from operating activities in 2011 totaled $2.1 billion, an increase of $675 million as compared to 2010. The increase in cash provided from operating activities was primarily due to accrued taxes and deferred income taxes related to benefits associated with bonus depreciation, other current liabilities, accounts payable, and depreciation and amortization.

Net cash used for investing activities totaled $0.9 billion for 2012 and $1.0 billion for 2011 and 2010, primarily due to gross property additions to utility plant of $0.9 billion, $1.0 billion, and $0.9 billion for 2012, 2011, and 2010, respectively. In 2012, these additions were primarily due to gross property additions related to nuclear fuel and transmission, distribution, and steam generating equipment. In the prior years, gross property 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 $649 million in 2012 primarily due to issuances, redemptions, and a maturity of senior notes, and payment of common stock dividends to Southern Company. Net cash used for financing activities totaled $869 million in 2011 primarily due to issuances, redemptions, and a maturity of debt securities and payment of higher common stock dividends. Net cash used for financing activities totaled $600 million in 2010 primarily due to the payment of common stock dividends. 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 2012 include increases of $297 million in long-term debt, $269 million in property, plant, and equipment associated with routine property additions, $147 million in accumulated deferred income taxes related to bonus depreciation, $89 million in other regulatory assets, deferred, and $131 million in fossil fuel stock, at average cost, partially offset by decreases of $250 million of securities due within one year and $207 million in cash and cash equivalents.

The Company's ratio of common equity to total capitalization, including short-term debt, was 44.0% in 2012 and 43.9% in 2011. 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 in the Southern Company system.

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.

At December 31, 2012, the Company had approximately $137 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2012 were as follows:

Expires[a]					Executable Term-Loans		Due Within One Year	
2013	2014	2016	Total	Unused	One Year	Two Years	Term Out	Not Term Out
			(in millions)					
$ 158	$ 350	$ 800	$ 1,308	$ 1,308	$ 56	$ —	$ 56	$ 102

(a) No credit arrangements expire in 2015.

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

Most of these arrangements contain covenants that limit debt levels and contain cross default provisions that are restricted only to the indebtedness (including guarantee obligations) of the Company. The Company is currently in compliance with all such covenants. The Company expects to renew its credit arrangements as needed, prior to expiration.

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. These credit arrangements provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper borrowings. As of December 31, 2012, the Company had $793 million of outstanding pollution control revenue bonds requiring liquidity support.

The Company may meet short-term cash needs through its commercial paper program. 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. The obligations of each company under these arrangements are several and there is no cross-affiliate credit support.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period [a]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		(in millions)		(in millions)
December 31, 2012:					
Commercial paper	**$ —**	**—%**	**$ 6**	**0.2%**	**$ 57**
December 31, 2011:					
Commercial paper	$ —	—%	$ 20	0.2%	$ 255
December 31, 2010:					
Commercial paper	$ —	—%	$ 7	0.2%	$ 135

(a) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2012, 2011, and 2010.

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 January 2012, the Company issued $250 million aggregate principal amount of Series 2012A 4.10% Senior Notes due January 15, 2042. The proceeds were used for general corporate purposes, including the Company's continuous construction program. The Company settled $100 million of interest rate swaps related to this issuance at a cost of $1 million. The cost is being amortized to interest expense, in earnings, over 10 years.

In March 2012, the Company redeemed approximately $1 million aggregate principal amount of The Industrial Development Board of the Town of West Jefferson Solid Waste Disposal Revenue Bonds (Alabama Power Company Miller Plant Project), Series 2008.

In April 2012, the Company redeemed $250 million aggregate principal amount of its Series 2007B 5.875% Senior Notes due April 1, 2047.

In October 2012, the Company issued $400 million aggregate principal amount of Series 2012B 0.550% Senior Notes due October 15, 2015. The proceeds were used to redeem $200 million aggregate principal amount of Series 2007C 6.00% Senior Insured Monthly Notes due October 15, 2037, and for general corporate purposes, including the Company's continuous construction program.

In December 2012, the Company issued $350 million aggregate principal amount of Series 2012C 3.85% Senior Notes due December 1, 2042. The proceeds, together with other funds of the Company, were used to pay, at maturity, $500 million aggregate amount of the Company's Series 2007D 4.85% Senior Notes due December 15, 2012. The Company settled $300 million of interest rate swaps related to the issuance of the Series 2012C Senior Notes at a cost of $35 million. The cost is being amortized to interest expense, in earnings, over 10 years.

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, 2012, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $273 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 and the variable rate pollution control revenue bond 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 $984 million of long-term variable interest rate exposure that has not been hedged at January 1, 2013 was 0.80%. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $10 million at January 1, 2013. See Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements for additional information.

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, 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. The Company had no material change in market risk exposure for the year ended December 31, 2012 when compared to the December 31, 2011 reporting period.

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, substantially all of which are composed of regulatory hedges, for the years ended December 31 were as follows:

	2012 Changes	2011 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (48)**	$ (38)
Contracts realized or settled	**46**	37
Current period changes[(a)]	**(11)**	(47)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (13)**	$ (48)

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

The changes in the fair value positions of the energy-related derivative contracts, which are substantially all attributable to both the volume and the price of natural gas, for the years ended December 31 were as follows:

	2012 Changes	2011 Changes
	Fair Value	
	(in millions)	
Natural gas swaps	**$ 30**	$ (5)
Natural gas options	**5**	(5)
Other energy-related derivatives	**—**	—
Total changes	**$ 35**	$ (10)

The net hedge volumes of energy-related derivative contracts, for the years ended December 31 were as follows:

	2012	2011
	mmBtu* Volume	
	(in millions)	
Commodity – Natural gas swaps	**45**	30
Commodity – Natural gas options	**12**	9
Total hedge volume	**57**	39

*million British thermal units (mmBtu)

The weighted average swap contract cost above market prices was approximately $0.30 per mmBtu as of December 31, 2012 and $1.45 per mmBtu as of December 31, 2011. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. The majority of the natural gas hedge gains and losses are recovered through the Company's retail energy cost recovery clause.

At December 31, 2012 and 2011, 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 energy 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 market observable, and thus fall into Level 2. See Note 10 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2012 were as follows:

	Fair Value Measurements December 31, 2012		
	Total	Maturity	
	Fair Value	Year 1	Years 2&3
		(in millions)	
Level 1	$ —	$ —	$ —
Level 2	(13)	(12)	(1)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$ (13)	$ (12)	$ (1)

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, Inc. and Standard & Poor's Ratings Services, 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.

Capital Requirements and Contractual Obligations

The Company's construction program consists of a base level capital investment and capital expenditures to comply with existing environmental statutes and regulations, including the MATS rule. Over the next three years, the Company estimates spending, as part of its base level capital investment, $553 million on Plant Farley (including nuclear fuel), $895 million on distribution facilities, and $698 million on transmission additions. These base level capital investment amounts also include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. Proposed water and coal combustion byproducts rules are not included in the construction program base level capital investment. The Company's base level construction program investments including investments to comply with existing environmental statutes and regulations and the estimated incremental compliance costs related to the proposed water and coal combustion byproducts rules over the 2013 through 2015 three-year period, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule, are estimated as follows:

	2013	2014	2015
Construction program:		*(in millions)*	
Base capital	$ 954	$ 1,117	$ 1,171
Existing environmental statutes and regulations, including the MATS rule	195	424	411
Total construction program base level capital investment	**$ 1,149**	**$ 1,541**	**$ 1,582**
Potential incremental environmental compliance investments:			
Proposed water and coal combustion byproducts rules	$ 5	$ 10	$ 160

See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information.

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; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in the expected environmental compliance program; 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.

In addition to the funds required for the Company's construction program, approximately $704 million will be required by the end of 2015 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.

As a result of NRC 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." 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, 2, 5, 6, 7, and 11 to the financial statements for additional information.

Contractual Obligations

	2013	2014-2015	2016-2017	After 2017	Uncertain Timing[(d)]	Total
			(in millions)			
Long-term debt[(a)] —						
Principal	$ 250	$ 454	$ 761	$ 4,717	$ —	$ 6,182
Interest	250	472	457	3,420	—	4,599
Preferred and preference stock dividends[(b)]	39	79	79	—	—	197
Financial derivative obligations[(c)]	14	4	—	—	—	18
Operating leases	20	20	13	9	—	62
Unrecognized tax benefits[(d)]	—	—	—	—	31	31
Purchase commitments —						
Capital[(e)]	1,028	2,754	—	—	—	3,782
Fuel[(f)]	1,385	2,088	646	560	—	4,679
Purchased power[(g)]	39	106	112	525	—	782
Other[(h)]	43	82	38	32	—	195
Pension and other postretirement benefit plans[(i)]	18	36	—	—	—	54
Total	$ 3,086	$ 6,095	$ 2,106	$ 9,263	$ 31	$ 20,581

(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, 2013, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk.

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

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

(d) The timing related to the realization of $31 million in unrecognized tax benefits 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 under "Unrecognized Tax Benefits" for additional information.

(e) The Company provides estimated capital expenditures for a three-year period, including estimated capital expenditures and compliance costs associated with existing environmental regulations, including the MATS rule. Such amounts exclude the Company's estimates of potential incremental environmental compliance investment to comply with proposed water and coal combustion byproducts rules, which are approximately $5 million, $10 million, and $160 million for years 2013, 2014, and 2015, respectively. These amounts also exclude contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements, which are reflected separately. At December 31, 2012, significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information.

(f) Includes commitments to purchase coal, nuclear fuel, and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2012.

(g) Estimated minimum long-term obligations for various long-term commitments for the purchase of capacity and energy. Amounts are related to the Company's certificated PPAs which include MWs purchased from gas-fired and wind-powered facilities.

(h) Includes long-term service agreements and contracts for the procurement of limestone. Long-term service agreements include price escalation based on inflation indices.

(i) The Company forecasts contributions to the pension and other postretirement benefit plans over a three-year period. The Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from the Company's corporate assets. 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 2012 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales, retail rates, customer growth, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related estimated expenditures, access to sources of capital, projections for the qualified pension plan, postretirement benefit plan, and nuclear decommissioning trust fund contributions, financing activities, filings with state and federal regulatory authorities, impact of the Tax Relief Act, impact of the ATRA, 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, environmental laws including regulation of water, 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, pending EPA civil action against the Company, and Internal Revenue Service and state tax audits;
- 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), the effects of energy conservation measures, and any potential economic impacts resulting from federal fiscal decisions;
- 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;
- the inherent risks involved in operating nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, or financial risks;
- 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, including cyber intrusion;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the impacts of any potential U.S. credit rating downgrade or other sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and

- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

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

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STATEMENTS OF INCOME
For the Years Ended December 31, 2012, 2011, and 2010
Alabama Power Company 2012 Annual Report

	2012	2011	2010
		(in millions)	
Operating Revenues:			
Retail revenues	$ 4,933	$ 4,972	$ 5,076
Wholesale revenues, non-affiliates	277	287	465
Wholesale revenues, affiliates	111	244	236
Other revenues	199	199	199
Total operating revenues	5,520	5,702	5,976
Operating Expenses:			
Fuel	1,503	1,679	1,851
Purchased power, non-affiliates	73	73	72
Purchased power, affiliates	182	198	208
Other operations and maintenance	1,287	1,262	1,418
Depreciation and amortization	639	637	606
Taxes other than income taxes	340	339	332
Total operating expenses	4,024	4,188	4,487
Operating Income	1,496	1,514	1,489
Other Income and (Expense):			
Allowance for equity funds used during construction	19	22	36
Interest income	16	18	17
Interest expense, net of amounts capitalized	(287)	(299)	(303)
Other income (expense), net	(24)	(30)	(30)
Total other income and (expense)	(276)	(289)	(280)
Earnings Before Income Taxes	1,220	1,225	1,209
Income taxes	477	478	463
Net Income	743	747	746
Dividends on Preferred and Preference Stock	39	39	39
Net Income After Dividends on Preferred and Preference Stock	$ 704	$ 708	$ 707

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2012, 2011, and 2010
Alabama Power Company 2012 Annual Report

	2012	2011	2010
		(in millions)	
Net Income	**$ 743**	$ 747	$ 746
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of \$(7), \$(5), and \$-, respectively	**(11)**	(9)	—
Reclassification adjustment for amounts included in net income, net of tax of \$1, \$(1), and \$(1), respectively	**2**	(2)	(2)
Total other comprehensive income (loss)	**(9)**	(11)	(2)
Comprehensive Income	**$ 734**	$ 736	$ 744

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2012, 2011, and 2010
Alabama Power Company 2012 Annual Report

	2012	2011	2010
		(in millions)	
Operating Activities:			
Net income	**$ 743**	$ 747	$ 746
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	**767**	749	694
Deferred income taxes	**164**	459	410
Allowance for equity funds used during construction	**(19)**	(22)	(36)
Pension, postretirement, and other employee benefits	**(11)**	(32)	(15)
Pension and postretirement funding	**(10)**	(9)	(55)
Stock based compensation expense	**9**	6	5
Natural disaster reserve	**3**	34	52
Other, net	**(27)**	(41)	(27)
Changes in certain current assets and liabilities —			
-Receivables	**23**	18	(29)
-Fossil fuel stock	**(132)**	47	(1)
-Materials and supplies	**(21)**	(33)	(20)
-Other current assets	**(4)**	(6)	(4)
-Accounts payable	**(77)**	11	(54)
-Accrued taxes	**(12)**	157	(140)
-Accrued compensation	**(3)**	(12)	28
-Other current liabilities	**(17)**	(25)	(181)
Net cash provided from operating activities	**1,376**	2,048	1,373
Investing Activities:			
Property additions	**(867)**	(977)	(903)
Investment in restricted cash from pollution control bonds	**1**	4	—
Distribution of restricted cash from pollution control bonds	**—**	13	18
Nuclear decommissioning trust fund purchases	**(194)**	(350)	(237)
Nuclear decommissioning trust fund sales	**193**	349	236
Cost of removal net of salvage	**(33)**	(28)	(44)
Change in construction payables	**12**	(9)	(45)
Other investing activities	**(46)**	9	(12)
Net cash used for investing activities	**(934)**	(989)	(987)
Financing Activities:			
Proceeds —			
Capital contributions from parent company	**27**	12	28
Senior notes issuances	**1,000**	700	250
Redemptions —			
Pollution control revenue bonds	**(1)**	(4)	—
Senior notes	**(950)**	(750)	(250)
Payment of preferred and preference stock dividends	**(39)**	(39)	(39)
Payment of common stock dividends	**(684)**	(774)	(586)
Other financing activities	**(2)**	(14)	(3)
Net cash used for financing activities	**(649)**	(869)	(600)
Net Change in Cash and Cash Equivalents	**(207)**	190	(214)
Cash and Cash Equivalents at Beginning of Year	**344**	154	368
Cash and Cash Equivalents at End of Year	**$ 137**	$ 344	$ 154
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $7, $9 and $14 capitalized, respectively)	**$ 273**	$ 286	$ 288
Income taxes (net of refunds)	**309**	(139)	188
Noncash transactions - accrued property additions at year-end	**31**	19	28

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

BALANCE SHEETS
At December 31, 2012 and 2011
Alabama Power Company 2012 Annual Report

Assets	**2012**	2011
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 137**	$ 344
Restricted cash	**—**	1
Receivables —		
Customer accounts receivable	**321**	332
Unbilled revenues	**138**	126
Under recovered regulatory clause revenues	**23**	—
Other accounts and notes receivable	**42**	35
Affiliated companies	**55**	79
Accumulated provision for uncollectible accounts	**(8)**	(10)
Fossil fuel stock, at average cost	**475**	344
Materials and supplies, at average cost	**395**	375
Vacation pay	**61**	59
Prepaid expenses	**81**	74
Other regulatory assets, current	**24**	44
Other current assets	**13**	11
Total current assets	**1,757**	1,814
Property, Plant, and Equipment:		
In service	**21,407**	20,809
Less accumulated provision for depreciation	**7,761**	7,344
Plant in service, net of depreciation	**13,646**	13,465
Nuclear fuel, at amortized cost	**354**	330
Construction work in progress	**438**	374
Total property, plant, and equipment	**14,438**	14,169
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**53**	62
Nuclear decommissioning trusts, at fair value	**605**	540
Miscellaneous property and investments	**78**	73
Total other property and investments	**736**	675
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**525**	532
Prepaid pension costs	**—**	59
Deferred under recovered regulatory clause revenues	**11**	48
Other regulatory assets, deferred	**1,083**	994
Other deferred charges and assets	**162**	186
Total deferred charges and other assets	**1,781**	1,819
Total Assets	**$ 18,712**	$ 18,477

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

Liabilities and Stockholder's Equity	2012	2011
	(in millions)	
Current Liabilities:		
Securities due within one year	$ **250**	$ 500
Accounts payable —		
Affiliated	**191**	203
Other	**318**	322
Customer deposits	**85**	85
Accrued taxes —		
Accrued income taxes	**5**	32
Other accrued taxes	**33**	34
Accrued interest	**62**	63
Accrued vacation pay	**50**	48
Accrued compensation	**94**	95
Liabilities from risk management activities	**14**	54
Other regulatory liabilities, current	**3**	18
Other current liabilities	**38**	38
Total current liabilities	**1,143**	1,492
Long-Term Debt (See accompanying statements)	**5,929**	5,632
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**3,404**	3,257
Deferred credits related to income taxes	**79**	83
Accumulated deferred investment tax credits	**141**	149
Employee benefit obligations	**321**	343
Asset retirement obligations	**589**	553
Other cost of removal obligations	**759**	703
Other regulatory liabilities, deferred	**183**	156
Other deferred credits and liabilities	**81**	82
Total deferred credits and other liabilities	**5,557**	5,326
Total Liabilities	**12,629**	12,450
Redeemable Preferred Stock (See accompanying statements)	**342**	342
Preference Stock (See accompanying statements)	**343**	343
Common Stockholder's Equity (See accompanying statements)	**5,398**	5,342
Total Liabilities and Stockholder's Equity	$ **18,712**	$ 18,477
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2012 and 2011
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	2012	2011	2012	2011
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term debt payable to affiliated trusts —				
Variable rate (3.41% at 1/1/13) due 2042	**$ 206**	$ 206		
Long-term notes payable —				
4.85% due 2012	**—**	500		
5.80% due 2013	**250**	250		
0.55% due 2015	**400**	—		
5.20% due 2016	**200**	200		
5.50% to 5.55% due 2017	**525**	525		
3.375% to 6.125% due 2019-2047	**3,450**	3,300		
Total long-term notes payable	**4,825**	4,775		
Other long-term debt —				
Pollution control revenue bonds —				
0.58% to 5.00% due 2034	**367**	367		
Variable rate (0.13% at 1/1/13) due 2015	**54**	54		
Variable rates (0.13% to 0.17% at 1/1/13) due 2017	**36**	36		
Variable rates (0.08% to 0.20% at 1/1/13) due 2021-2038	**694**	694		
Total other long-term debt	**1,151**	1,151		
Unamortized debt premium (discount), net	**(3)**	—		
Total long-term debt (annual interest requirement — $250 million)	**6,179**	6,132		
Less amount due within one year	**250**	500		
Long-term debt excluding amount due within one year	**5,929**	5,632	**49.4%**	48.4%

STATEMENTS OF CAPITALIZATION (continued)
At December 31, 2012 and 2011
Alabama Power Company 2012 Annual Report

		2012		2011	2012	2011
		(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 million)		**294**		294		
Total redeemable preferred stock		**342**		342	**2.8**	2.9
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 million)		**343**		343	**2.9**	2.9
Common Stockholder's Equity:						
Common stock, par value $40 per share —						
Authorized: 40,000,000 shares						
Outstanding: 30,537,500 shares		**1,222**		1,222		
Paid-in capital		**2,227**		2,182		
Retained earnings		**1,976**		1,956		
Accumulated other comprehensive income (loss)		**(27)**		(18)		
Total common stockholder's equity		**5,398**		5,342	**44.9**	45.8
Total Capitalization	**$**	**12,012**	$	11,659	**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, 2012, 2011, and 2010
Alabama Power Company 2012 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, 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
Net income after dividends on preferred and preference stock	—	—	—	708	—	708
Capital contributions from parent company	—	—	26	—	—	26
Other comprehensive income (loss)	—	—	—	—	(11)	(11)
Cash dividends on common stock	—	—	—	(774)	—	(774)
Balance at December 31, 2011	**31**	**1,222**	**2,182**	**1,956**	**(18)**	**5,342**
Net income after dividends on preferred and preference stock	—	—	—	**704**	—	**704**
Capital contributions from parent company	—	—	**45**	—	—	**45**
Other comprehensive income (loss)	—	—	—	—	**(9)**	**(9)**
Cash dividends on common stock	—	—	—	**(684)**	—	**(684)**
Balance at December 31, 2012	**31**	**$ 1,222**	**$ 2,227**	**$ 1,976**	**$ (27)**	**$ 5,398**

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 The Southern Company (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 territory located in the State of Alabama in addition to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, 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 primarily for Southern Company's investments in leveraged leases. Southern Nuclear operates and provides services to the Southern Company system'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 (VIEs) 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 $340 million, $347 million, and $371 million during 2012, 2011, and 2010, respectively. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the Securities and Exchange Commission (SEC). Subsequently, additional cost allocation methodologies have been reported to the FERC 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, $215 million, and $218 million during 2012, 2011, and 2010, 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 $12 million in 2012, $12 million in 2011, and $11 million in 2010. Also, Mississippi Power reimburses the Company for any direct fuel purchases delivered from one of the Company's transfer facilities, which were $28 million in 2012, $21 million in 2011, and $16 million in 2010. See Note 4 for additional information.

Due to the expiration of the Plant Harris power purchase agreement (PPA) with Southern Power in 2010, no purchased power costs or fuel costs were recognized in 2012 or 2011 associated with this PPA. Additionally, the Company recorded no prepaid capacity expenses in 2012 or 2011. The Company's purchased power costs from Plant Harris in 2010 totaled $15 million. The Company also provided the fuel, at cost, associated with the PPA totaling $21 million in 2010. See Note 7 under "Fuel and Purchased Power Agreements" 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 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 \$38 million in 2012, \$22 million in 2013, and \$29 million in 2014. The Company expects to recover a majority of these costs through a tariff with Gulf Power until 2023. The remainder of these costs will be recovered through normal rate mechanisms.

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 material services to or from affiliates in 2012, 2011, or 2010.

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

The traditional operating companies, including the Company and Southern Power, may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

New Accounting Pronouncements

In June 2011, the Financial Accounting Standards Board (FASB) issued guidance, ASU 2011-05, *Presentation of Comprehensive Income*, requiring companies to present the total of comprehensive income, the components of net income, and the components of other comprehensive income, in a single continuous statement of comprehensive income or in two separate but consecutive statements. In October 2012, the FASB issued additional guidance, ASU 2012-04, *Technical Corrections and Improvements* (ASU 2012-04), in which it clarified that those companies presenting consecutive statements must begin the statement of comprehensive income with net income. The Company retroactively adopted the guidance in ASU 2012-04 beginning with its financial statements for the three years ended December 31, 2012, 2011, and 2010.

Regulatory Assets and Liabilities

The Company is subject to the provisions of the FASB 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:

	2012	2011	Note
	(in millions)		
Deferred income tax charges	**$ 525**	$ 532	(a,k)
Loss on reacquired debt	**93**	84	(b)
Vacation pay	**61**	59	(c,j)
Under/(over) recovered regulatory clause revenues	**34**	47	(d)
Fuel hedging (realized and unrealized) losses	**18**	48	(e)
Other regulatory assets	**51**	46	(f,l)
Asset retirement obligations	**(64)**	(35)	(a)
Other cost of removal obligations	**(759)**	(703)	(a)
Deferred income tax credits	**(79)**	(83)	(a)
Fuel hedging (realized and unrealized) gains	**(5)**	(1)	(e)
Mine reclamation and remediation	**(8)**	(8)	(g)
Nuclear outage	**33**	38	(d)
Natural disaster reserve	**(103)**	(110)	(h)
Other regulatory liabilities	**(5)**	(20)	(d,l)
Retiree benefit plans	**911**	822	(i,j)
Total regulatory assets (liabilities), net	**$ 703**	$ 716	

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 do not exceed three years. Upon final settlement, actual costs incurred are recovered through the energy cost recovery clause.

(f) Recorded as accepted by the Alabama PSC. Capitalized upon initialization of related construction projects, if applicable.

(g) Recorded as accepted by the Alabama PSC. Mine reclamation and remediation liabilities will be settled following completion of the related activities.

(h) Utilized as storm restoration and potential reliability-related expenses are incurred, as approved by the Alabama PSC.

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

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

(k) 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.

(l) Recovered and amortized as approved or accepted by the Alabama PSC over the life of the contract.

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 to income or reclassify to accumulated other comprehensive income (OCI) related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are reflected in rates. 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 period. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, 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 – Energy Cost Recovery" and "Retail Regulatory Matters – Rate CNP" for additional information.

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

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and 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 any 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 cost of equity funds used during construction.

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

	2012	2011
	(in millions)	
Generation	$ **11,110**	$ 10,982
Transmission	**3,137**	2,998
Distribution	**5,714**	5,517
General	**1,434**	1,300
Plant acquisition adjustment	**12**	12
Total plant in service	$ **21,407**	$ 20,809

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 other operations and maintenance expense as incurred or performed with the exception of nuclear refueling costs, which are recorded in accordance with specific Alabama PSC orders.

In 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.

During 2011, the Company deferred $38 million of nuclear outage expenses associated with the fall 2011 outage and began the first 18-month amortization cycle for expenses in January 2012. The Company deferred an additional $31 million of nuclear outage expenses associated with the spring 2012 outage and began the second amortization cycle in July 2012. The total unamortized deferred nuclear outage expense balance of $33 million is included in the 2012 balance sheet as a regulatory asset.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.2% in 2012, 3.3% in 2011, and 3.3% in 2010. Depreciation studies are conducted periodically to update the composite rates and the information is provided to the Alabama PSC and the FERC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

In 2011, the Company submitted a depreciation study to the FERC and received authorization to use the recommended rates beginning January 2012. The study was also provided to the Alabama PSC.

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 for asset retirement obligations primarily relates to the decommissioning of 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" herein for additional information on amounts included in rates.

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

	2012	2011
	(in millions)	
Balance at beginning of year	**$ 553**	$ 520
Liabilities incurred	**—**	—
Liabilities settled	**(1)**	(2)
Accretion	**37**	35
Balance at end of year	**$ 589**	$ 553

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 (Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. 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 that the Funds' managers may not invest in any securities of the utility for which it manages funds or its affiliates, except for investments tied to market indices or other mutual funds. 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 management of the Company. The Funds' managers are authorized, within certain investment guidelines, 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, as management believes that fair value best represents the nature of the Funds. 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, 2012, investment securities in the Funds totaled $604 million consisting of equity securities of $438 million, debt securities of $156 million, and $10 million of other securities. At December 31, 2011, investment securities in the Funds totaled $539 million consisting of equity securities of $382 million, debt securities of $146 million, and $11 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 $193 million, $349 million, and $236 million in 2012, 2011, and 2010, respectively, all of which were reinvested. For 2012, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $70 million, of which $4 million related to realized gains and $50 million related to unrealized gains related to securities held in the Funds at December 31, 2012. For 2011, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $6 million, of which $41 million related to realized gains and $51 million related to unrealized losses related to securities held in the Funds at December 31, 2011. 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. 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 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, 2012, the accumulated provisions for decommissioning were as follows:

	(in millions)
External trust funds	$ 604
Internal reserves	22
Total	$ 626

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

Decommissioning periods:	
Beginning year	2037
Completion year	2065

		(in millions)
Site study costs:		
Radiated structures	$	1,060
Non-radiated structures		72
Total site study costs	$	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 Funds 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

In accordance with regulatory treatment, the Company records allowance for funds used during construction (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, AFUDC 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 2012, 9.2% in 2011, and 9.4% in 2010. AFUDC, net of income taxes, as a percent of net income after dividends on preferred and preference stock was 3.3% in 2012, 3.9% in 2011, and 6.3% in 2010.

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 Natural Disaster Reserve (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 the authority, based on an order from the Alabama PSC, to accrue certain additional amounts as circumstances warrant. The order 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.

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. See Note 3 under "Natural Disaster Reserve" herein for additional information.

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 cost of coal, natural gas, oil, transportation, and emissions allowances. Fuel is charged to inventory when purchased and then expensed, at weighted average cost, as used and recovered by the Company through energy 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 material 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 had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2012.

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

Comprehensive Income

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

Variable Interest Entities

The primary beneficiary of a VIE is required to consolidate the VIE when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE.

The Company has established a wholly-owned trust to issue preferred securities. See Note 6 under "Long-Term Debt Payable to an Affiliated Trust" for additional information. However, the Company is not considered the primary beneficiary of the trust. Therefore, the investment in the trust is reflected as other investments, and the related loan from the trust is 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). No contributions to the qualified pension plan were made for the year ended December 31, 2012. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2013. 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, 2013, other postretirement trust contributions are expected to total approximately $4 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 2009 for the 2010 plan year using discount rates for the pension plans and the other postretirement benefit plans of 5.93% and 5.84%, respectively, and an annual salary increase of 4.18%.

	2012	2011	2010
Discount rate:			
Pension plans	**4.27%**	4.98%	5.52%
Other postretirement benefit plans	**4.06**	4.88	5.41
Annual salary increase	**3.59**	3.84	3.84
Long-term return on plan assets:			
Pension plans	**8.20**	8.45	8.45
Other postretirement benefit plans	**7.19**	7.39	7.43

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) is the weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2012 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate Is Reached
Pre-65	8.00%	5.00%	2020
Post-65 medical	6.00	5.00	2020
Post-65 prescription	6.00	5.00	2020

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, 2012 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$ 32	$ (27)
Service and interest costs	2	(1)

Pension Plans

The total accumulated benefit obligation for the pension plans was $2.0 billion at December 31, 2012 and $1.8 billion at December 31, 2011. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2012 and 2011 were as follows:

	2012	2011
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 1,932**	$ 1,779
Service cost	**44**	43
Interest cost	**94**	96
Benefits paid	**(90)**	(88)
Actuarial loss	**238**	102
Balance at end of year	**2,218**	1,932
Change in plan assets		
Fair value of plan assets at beginning of year	**1,885**	1,933
Actual return on plan assets	**274**	32
Employer contributions	**8**	8
Benefits paid	**(90)**	(88)
Fair value of plan assets at end of year	**2,077**	1,885
Accrued liability	**$ (141)**	$ (47)

At December 31, 2012, the projected benefit obligations for the qualified and non-qualified pension plans were $2.1 billion and $121 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2012 and 2011 related to the Company's pension plans consist of the following:

	2012	2011
	(in millions)	
Prepaid pension costs	$ —	$ 59
Other regulatory assets, deferred	822	727
Other current liabilities	(8)	(7)
Employee benefit obligations	(133)	(99)

Presented below are the amounts included in regulatory assets at December 31, 2012 and 2011 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 2013.

	2012	2011	Estimated Amortization in 2013
		(in millions)	
Prior service cost	$ 26	$ 33	$ 7
Net (gain) loss	796	694	52
Other regulatory assets, deferred	$ 822	$ 727	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2012 and 2011 are presented in the following table:

	Regulatory Assets
	(in millions)
Balance at December 31, 2010	$ 497
Net (gain) loss	243
Change in prior service costs	—
Reclassification adjustments:	
Amortization of prior service costs	(9)
Amortization of net gain (loss)	(4)
Total reclassification adjustments	(13)
Total change	230
Balance at December 31, 2011	$ 727
Net (gain) loss	125
Change in prior service costs	—
Reclassification adjustments:	
Amortization of prior service costs	(7)
Amortization of net gain (loss)	(23)
Total reclassification adjustments	(30)
Total change	95
Balance at December 31, 2012	$ 822

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

	2012	2011	2010
		(in millions)	
Service cost	$ 44	$ 43	$ 41
Interest cost	94	96	97
Expected return on plan assets	(162)	(173)	(168)
Recognized net (gain) loss	23	4	2
Net amortization	7	9	9
Net periodic pension cost (income)	$ 6	$ (21)	$ (19)

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, 2012, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2013	$ 99
2014	104
2015	108
2016	112
2017	117
2018 to 2022	637

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2012 and 2011 were as follows:

	2012	2011
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$ 470	$ 454
Service cost	5	5
Interest cost	22	24
Benefits paid	(24)	(27)
Actuarial loss	15	11
Plan amendments	—	—
Retiree drug subsidy	2	3
Balance at end of year	490	470
Change in plan assets		
Fair value of plan assets at beginning of year	315	323
Actual return on plan assets	39	5
Employer contributions	11	11
Benefits paid	(22)	(24)
Fair value of plan assets at end of year	343	315
Accrued liability	$ (147)	$ (155)

Amounts recognized in the balance sheets at December 31, 2012 and 2011 related to the Company's other postretirement benefit plans consist of the following:

	2012	2011
	(in millions)	
Regulatory assets	$ 89	$ 96
Employee benefit obligations	(147)	(155)

Presented below are the amounts included in regulatory assets at December 31, 2012 and 2011 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 2013.

	2012	2011	Estimated Amortization in 2013
		(in millions)	
Prior service cost	$ 22	$ 26	$ 4
Net (gain) loss	67	68	2
Transition obligation	—	2	—
Regulatory assets	$ 89	$ 96	

The changes in the balance of regulatory assets related to the other postretirement benefit plans for the plan years ended December 31, 2012 and 2011 are presented in the following table:

	Regulatory Assets
	(in millions)
Balance at December 31, 2010	$ 72
Net (gain) loss	31
Change in prior service costs/transition obligation	—
Reclassification adjustments:	
Amortization of transition obligation	(3)
Amortization of prior service costs	(4)
Amortization of net gain (loss)	—
Total reclassification adjustments	(7)
Total change	24
Balance at December 31, 2011	$ 96
Net (gain) loss	**(1)**
Change in prior service costs/transition obligation	—
Reclassification adjustments:	
Amortization of transition obligation	**(2)**
Amortization of prior service costs	**(4)**
Amortization of net gain (loss)	—
Total reclassification adjustments	**(6)**
Total change	**(7)**
Balance at December 31, 2012	**$ 89**

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

	2012	2011	2010
		(in millions)	
Service cost	**$ 5**	$ 5	$ 6
Interest cost	**22**	24	26
Expected return on plan assets	**(23)**	(25)	(25)
Net amortization	**6**	7	7
Net postretirement cost	**$ 10**	$ 11	$ 14

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 Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

	Benefit Payments	Subsidy Receipts	Total
		(in millions)	
2013	$ 30	$ (3)	$ 27
2014	32	(4)	28
2015	33	(4)	29
2016	34	(4)	30
2017	35	(5)	30
2018 to 2022	176	(26)	150

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). 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, 2012 and 2011, along with the targeted mix of assets for each plan, is presented below:

	Target	**2012**	2011
Pension plan assets:			
Domestic equity	26%	**28%**	29%
International equity	25	**24**	25
Fixed income	23	**27**	23
Special situations	3	**1**	—
Real estate investments	14	**13**	14
Private equity	9	**7**	9
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	44%	**46%**	41%
International equity	20	**20**	14
Domestic fixed income	24	**28**	38
Special situations	1	**—**	—
Real estate investments	8	**4**	4
Private equity	3	**2**	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 generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Trust-owned life insurance (TOLI).*** Investments of the Company's taxable trusts aimed at minimizing the impact of taxes on the portfolio.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments 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, 2012 and 2011. The fair values presented are prepared in accordance with GAAP. 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.

Valuation methods of the primary fair value measurements disclosed in the following tables are as follows:

- **Investments in equity securities:** Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- **Investments in fixed income securities:** Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- **Investments in TOLI**: Investments in TOLI policies are classified as Level 2 investments and are valued based on the underlying investments held in the policy's separate account. The underlying assets are equity and fixed income pooled funds that are comprised of Level 1 and Level 2 securities.
- **Investments in private equity and real estate:** Investments in private equity and real estate are generally classified as Level 3 as the underlying assets typically do not have observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. In the case of private equity, techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, and discounted cash flow analysis. Real estate managers generally use prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals to value underlying real estate investments. The fair value of partnerships is determined by aggregating the value of the underlying assets.

The fair values of pension plan assets as of December 31, 2012 and 2011 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2012:	**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*	$ 304	$ 175	$ —	$ 479
International equity*	238	256	—	494
Fixed income:				
U.S. Treasury, government, and agency bonds	—	135	—	135
Mortgage- and asset-backed securities	—	33	—	33
Corporate bonds	—	230	1	231
Pooled funds	—	104	—	104
Cash equivalents and other	1	143	—	144
Real estate investments	67	—	220	287
Private equity	—	—	155	155
Total	$ 610	$ 1,076	$ 376	$ 2,062

* 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, 2011:	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*	$ 320	$ 148	$ —	$ 468
International equity*	329	94	—	423
Fixed income:				
U.S. Treasury, government, and agency bonds	—	120	—	120
Mortgage- and asset-backed securities	—	37	—	37
Corporate bonds	—	232	1	233
Pooled funds	—	105	—	105
Cash equivalents and other	—	39	—	39
Real estate investments	61	—	217	278
Private equity	—	—	161	161
Total	$ 710	$ 775	$ 379	$ 1,864

* 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, 2012 and 2011 were as follows:

	2012		2011	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
	(in millions)			
Beginning balance	**$ 217**	**$ 161**	$ 191	$ 180
Actual return on investments:				
Related to investments held at year end	**2**	**—**	16	(3)
Related to investments sold during the year	**1**	**2**	6	9
Total return on investments	**3**	**2**	22	6
Purchases, sales, and settlements	**—**	**(8)**	4	(25)
Transfers into/out of Level 3	**—**	**—**	—	—
Ending balance	**$ 220**	**$ 155**	$ 217	$ 161

The fair values of other postretirement benefit plan assets as of December 31, 2012 and 2011 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

As of December 31, 2012:	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	$ 9	$ —	$ 71
International equity*	12	13	—	25
Fixed income:				
U.S. Treasury, government, and agency bonds	—	7	—	7
Mortgage- and asset-backed securities	—	2	—	2
Corporate bonds	—	11	—	11
Pooled funds	—	5	—	5
Cash equivalents and other	—	19	—	19
Trust-owned life insurance	—	178	—	178
Real estate investments	4	—	11	15
Private equity	—	—	8	8
Total	$ 78	$ 244	$ 19	$ 341

* 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, 2011:	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*	$ 57	$ 8	$ —	$ 65
International equity*	17	5	—	22
Fixed income:				
U.S. Treasury, government, and agency bonds	—	9	—	9
Mortgage- and asset-backed securities	—	2	—	2
Corporate bonds	—	12	—	12
Pooled funds	—	5	—	5
Cash equivalents and other	—	19	—	19
Trust-owned life insurance	—	160	—	160
Real estate investments	4	—	11	15
Private equity	—	—	8	8
Total	$ 78	$ 220	$ 19	$ 317

* 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, 2012 and 2011 were as follows:

	2012		2011	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
		(in millions)		
Beginning balance	$ 11	$ 8	$ 10	$ 9
Actual return on investments:				
Related to investments held at year end	—	—	1	—
Related to investments sold during the year	—	—	—	—
Total return on investments	—	—	1	—
Purchases, sales, and settlements	—	—	—	(1)
Transfers into/out of Level 3	—	—	—	—
Ending balance	$ 11	$ 8	$ 11	$ 8

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2012, 2011, and 2010 were $19 million, $18 million, and $18 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment, 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 air quality and water standards, has increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by carbon dioxide and other emissions, coal combustion byproducts, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, 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 ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

In 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including the Company, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by the Company and three coal-fired generating facilities operated by Georgia Power. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The case against Georgia Power was administratively closed in 2001 and has not been reopened. After the Company was dismissed from the original action, the EPA filed a separate action in 2001 against the Company in the U.S. District Court for the Northern District of Alabama.

In 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree, resolving claims relating to the alleged NSR violations at Plant Miller. In 2010, the EPA dismissed five of its eight remaining claims against the Company, leaving only three claims, including one relating to a unit co-owned by Mississippi Power. In March 2011, the U.S. District Court for the Northern District of Alabama granted the Company summary judgment on all remaining claims and dismissed the case with prejudice. That judgment is on appeal to the U.S. Court of Appeals for the Eleventh Circuit. On February 23, 2012, the EPA filed a motion in the U.S. District Court for the Northern District of Alabama seeking vacatur of the judgment and recusal of the judge in the case involving the Company.

The Company believes it complied with applicable laws and regulations 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, depending on the date of the alleged violation. An adverse outcome could require substantial 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.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit 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 allege 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 (including Southern Company) 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. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. While Southern Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether the Company will incur any liability in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. In May 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the plaintiffs' amended complaint. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. The Company believes that these claims are without merit. While the Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether the Company will incur any liability in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

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 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.

Nuclear Fuel Disposal Costs

Acting through the U.S. Department of Energy (DOE) and pursuant to the Nuclear Waste Policy Act of 1982, the U.S. government entered into a contract with the Company that requires the DOE to dispose of spent nuclear fuel and high level radioactive waste generated at Plant Farley. The DOE failed to timely perform and has yet to commence the performance of its contractual and statutory obligation to dispose of spent nuclear fuel beginning no later than January 31, 1998. Consequently, the Company has pursued and continues to pursue legal remedies against the U.S. government for its partial breach of contract.

As a result of the first lawsuit, the Company recovered approximately $17 million, representing substantially all of the Company's direct costs of the expansion of spent nuclear fuel storage facilities at Plant Farley from 1998 through 2004. In April 2012, the award was credited to cost of service for the benefit of customers.

In 2008, the Company filed a second lawsuit against the U.S. government for the costs of continuing to store spent nuclear fuel at Plant Farley. Damages are being sought for the period from January 1, 2005 through December 31, 2010. Damages will continue to accrue until the issue is resolved or storage is provided. No amounts have been recognized in the financial statements as of December 31, 2012 for any potential recoveries from the second lawsuit. The final outcome of this matter cannot be determined at this time; however, no material impact on the Company's net income is expected.

At Plant Farley, on-site dry spent fuel storage facilities are operational and can be expanded to accommodate spent fuel through the expected life of the plant.

Retail Regulatory Matters

Retail Rate Adjustments

In July 2011, the Alabama PSC issued an order to eliminate a tax-related adjustment under the Company's rate structure effective with October 2011 billings. The elimination of this adjustment resulted in additional revenues of approximately $31 million for 2011. In accordance with the order, the Company made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to such additional 2011 revenues. The NDR was impacted as a result of operations and maintenance expenses incurred in connection with the April 2011 storms in Alabama. See "Natural Disaster Reserve" below for additional information. The elimination of this adjustment resulted in additional revenues of approximately $106 million for 2012.

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 (ROE) is projected to be between 13.0% and 14.5%. If the Company's actual retail ROE 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 ROE fall below the allowed equity return range.

In 2011 and 2012, retail rates under Rate RSE remained unchanged from 2010. On November 30, 2012, the Company made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2013; projected earnings were within the specified return range, and, therefore, retail rates under Rate RSE remained unchanged for 2013. Under the terms of Rate RSE, the maximum possible increase for 2014 is 5.00%. However, the Company is working with the Alabama PSC to develop a plan that will potentially preclude the need for a Rate RSE increase in 2014. The ultimate outcome of this matter cannot be determined at this time.

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 under rate certificated new plant (Rate CNP). The Company may also recover retail costs associated with certificated PPAs under rate certificated new plant (Rate CNP PPA). Effective April 2011, Rate CNP PPA was reduced by approximately $5 million annually. On March 6, 2012, the Alabama PSC issued a consent order that the Company leave in effect the current Rate CNP PPA factor for billings for the period April 1, 2012 through March 31, 2013. It is anticipated that no adjustment will be made to Rate CNP PPA in 2013. As of December 31, 2012, the Company had an under recovered certificated PPA balance of $9 million, $7 million of which is included in deferred under recovered regulatory clause revenues and $2 million of which is included in under recovered regulatory clause revenues in the balance sheet.

On September 17, 2012, the Alabama PSC approved and certificated a PPA for the purchase of approximately 200 megawatts (MWs) of the approximately 400 MWs of energy from wind-powered generating facilities and all associated environmental attributes, including renewable energy credits. The terms of this PPA and a previously approved and certificated PPA permit the Company to use the energy and retire the associated environmental attributes in service of its customers or to sell environmental attributes, separately or bundled with energy, to third parties. Approximately 200 MWs of energy from wind-powered generating facilities was operational in December 2012.

Rate certificated new plant environmental (Rate CNP Environmental) also allows for the recovery of the Company's retail costs associated with environmental laws, regulations, or other such mandates. Rate CNP Environmental 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. There was no adjustment to Rate CNP Environmental to recover environmental costs in 2011 or 2012. On November 26, 2012, the Company submitted calculations associated with its cost of complying with environmental mandates, as provided under Rate CNP Environmental. The filing reflected a projected unrecovered retail revenue requirement for environmental compliance of less than $1 million, which is to be recovered in the billing months of January 2013 through December 2013. On December 4, 2012, the Alabama PSC issued a consent order that the Company leave in effect for 2013 the factors associated with the Company's environmental compliance costs for the year 2012. Any unrecovered amounts associated with 2013 will be reflected in the 2014 filing. As of December 31, 2012, the Company had an under recovered environmental clause balance of $21 million which is included in under recovered regulatory clause revenues in the balance sheet.

Environmental Accounting Order

Proposed and final environmental regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions. In September 2011, the Alabama PSC approved an order allowing for the establishment of a regulatory asset to record the unrecovered investment costs associated with any such decisions, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure. These costs would be amortized over the affected unit's remaining useful life, as established prior to the decision regarding early retirement.

Compliance and Pension Cost Accounting Order

On November 6, 2012, the Alabama PSC approved an accounting order for certain compliance-related operation and maintenance expenditures for the years 2013 through 2017, as well as the incremental increase in operation expense related to pension cost for 2013. Under the accounting order, expenses from January 2013 through December 2017 related to compliance with standards addressing Critical Infrastructure Protection issued by the North American Electric Reliability Corporation and cyber security requirements issued by the NRC will be deferred to a regulatory asset account and amortized over a three-year period beginning in January 2015. Expenses from January 2013 through December 2017 related to compliance with NRC guidance addressing the readiness at nuclear facilities within the U.S., as prompted by the earthquake and tsunami that struck Japan in March 2011, also will be deferred as a regulatory asset and recovered over the same amortization period. The compliance-related expenses to be afforded regulatory asset treatment over the five-year period are currently estimated to be approximately $43 million. In addition, the accounting order authorizes the Company to defer an incremental increase in its pension cost for 2013. That increased pension cost is estimated to be approximately $17 million. During 2013, the actual incremental increase will be deferred to a regulatory asset account and will be amortized over a three-year period beginning in January 2015. Pursuant to the accounting order, the Company has the ability to accelerate the amortization of the regulatory assets.

Energy Cost Recovery

The Company has established energy cost recovery rates under the Company's energy cost recovery rate (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). On December 4, 2012, the Alabama PSC issued a consent order that the Company leave in effect the energy cost recovery rates which began in April 2011 for 2013. Therefore, the Rate ECR factor as of January 1, 2013 remained at 2.681 cents per KWH. Effective with billings beginning in January 2014, the Rate ECR factor will be 5.910 cents per KWH, absent a further order from the Alabama PSC.

As of December 31, 2012 and 2011, the Company had under recovered fuel balances of approximately $4 million and $31 million, respectively, which are included in deferred under recovered regulatory clause revenues in the balance sheets. This classification is 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 recovery of the 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 the authority, based on an order from the Alabama PSC, to accrue certain additional amounts as circumstances warrant. The order 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.

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.

During the first half of 2011, multiple storms caused varying degrees of damage to the Company's transmission and distribution facilities. The most significant storms occurred in April 2011, causing over 400,000 of the Company's 1.4 million customers to be without electrical service. The cost of repairing the damage to facilities and restoring electrical service to customers as a result of these storms was $42 million for operations and maintenance expenses and $161 million for capital-related expenditures.

In accordance with the order that was issued by the Alabama PSC in July 2011 to eliminate a tax-related adjustment under the Company's rate structure that resulted in additional revenues, the Company made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to the additional 2011 revenues, which were approximately $31 million.

The accumulated balances in the NDR for the years ended December 31, 2012 and December 31, 2011 were approximately $103 million and $110 million, respectively. Any accruals to the NDR are included in the balance sheets under other regulatory liabilities, deferred and are reflected as other operations and maintenance expenses in the statements of income.

Nuclear Outage Accounting Order

In 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 at Plant Farley during the 18-month cycle for the outages. In accordance with the 2010 order, nuclear outage expenses are deferred when the charges actually occur and then amortized over the subsequent 18-month period.

The initial result of implementation of the accounting order was that no nuclear maintenance outage expenses were recognized from January 2011 through December 2011, which decreased nuclear outage operations and maintenance expenses in 2011 from 2010 by approximately $50 million. During the fall of 2011, approximately $38 million of actual nuclear outage expenses associated with one unit at Plant Farley was deferred to a regulatory asset account; beginning in January 2012, these deferred costs are being amortized to nuclear operations and maintenance expenses over an 18-month period. During the spring of 2012, approximately $31 million of actual nuclear outage expenses associated with the second unit at Plant Farley was deferred to a regulatory asset account; beginning in July 2012, these deferred costs are being 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 pursuant to the existing order.

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 MWs, as well as associated transmission facilities. The capacity of these units is sold equally to the Company and Georgia Power under a power contract. The Company and Georgia Power make payments sufficient to provide for the operating expenses, taxes, interest expense, and a return on equity. The Company's share of purchased power totaled $109 million in 2012, $142 million in 2011, and $101 million in 2010, 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. These senior notes mature on May 15, 2013. 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, 2012, the capitalization of SEGCO consisted of $82 million of equity and $75 million of long-term debt on which the annual interest requirement is $3 million. In addition, SEGCO had short-term debt outstanding of $45 million. SEGCO paid dividends of $14 million in 2012, $15 million in 2011, and $5 million in 2010, of which one-half of each was paid to the Company. In addition, the Company recognizes 50% of SEGCO's net income.

SEGCO plans to add natural gas as the primary fuel source in 2015 for 1,000 MWs of its generating capacity. It is currently planning and developing the necessary natural gas pipeline. The Company, which owns and operates a generating unit adjacent to the SEGCO generating units, has entered into a joint ownership agreement with SEGCO for the ownership of the gas pipeline. The Company will own 14% of the pipeline with the remaining 86% owned by SEGCO. At December 31, 2012, the Company's portion of the construction work in progress associated with the construction of the pipeline is $0.1 million.

In addition to the Company's ownership of SEGCO and joint ownership of the natural gas pipeline, the Company's percentage ownership and investment in jointly-owned coal-fired generating plants at December 31, 2012 were as follows:

Facility	Total Megawatt Capacity	Company Ownership	Plant in Service	Accumulated Depreciation	Construction Work in Progress
			(in millions)		
Greene County	500	60.00% (1)	$ 151	$ 89	$ 9
Plant Miller					
Units 1 and 2	1,320	91.84% (2)	1,401	551	8

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

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

On behalf of the Company, Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama, Georgia, and Mississippi. In addition, the Company files a separate company income tax return for the State of Tennessee. 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 current 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 federal tax liability.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2012	2011	2010
		(in millions)	
Federal —			
Current	$ 262	$ 20	$ 52
Deferred	137	377	333
	399	397	385
State —			
Current	51	(1)	1
Deferred	27	82	77
	78	81	78
Total	$ 477	$ 478	$ 463

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:

	2012	2011
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation	$ 2,989	$ 2,820
Property basis differences	420	439
Premium on reacquired debt	36	33
Employee benefit obligations	218	217
Under recovered energy clause	16	26
Regulatory assets associated with employee benefit obligations	378	343
Regulatory assets associated with asset retirement obligations	248	233
Other	114	94
Total	4,419	4,205
Deferred tax assets —		
Federal effect of state deferred taxes	194	186
State effect of federal deferred taxes	—	—
Unbilled fuel revenue	39	38
Storm reserve	34	38
Employee benefit obligations	408	373
Other comprehensive losses	19	14
Asset retirement obligations	248	233
Other	98	97
Total	1,040	979
Total deferred tax liabilities, net	3,379	3,226
Portion included in current assets (liabilities), net	25	31
Accumulated deferred income taxes	$ 3,404	$ 3,257

At December 31, 2012, the Company's tax-related regulatory assets to be recovered from customers were $525 million. These assets are primarily 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.

At December 31, 2012, the Company's tax-related regulatory liabilities to be credited to customers were $79 million. These liabilities are primarily 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 2012, 2011, and 2010. At December 31, 2012, all investment tax credits available to reduce federal income taxes payable had been utilized.

In 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (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 production-period projects placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term production-period projects to be placed in service in 2013). The application of the bonus depreciation provisions in the Tax Relief Act 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:

	2012	2011	2010
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**4.1**	4.3	4.2
Non-deductible book depreciation	**0.9**	0.8	0.8
Differences in prior years' deferred and current tax rates	**(0.1)**	(0.1)	(0.1)
AFUDC equity	**(0.5)**	(0.6)	(1.0)
Other	**(0.3)**	(0.4)	(0.6)
Effective income tax rate	**39.1%**	39.0%	38.3%

The increase in the Company's 2012 effective tax rate was not material.

The increase in the Company's 2011 effective tax rate was due to a decrease in the tax benefit of AFUDC equity 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" for additional information.

Unrecognized Tax Benefits

For 2012, the total amount of unrecognized tax benefits decreased by $1 million, resulting in a balance of $31 million as of December 31, 2012.

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

	2012	2011	2010
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ 32**	$ 43	$ 6
Tax positions from current periods	**5**	6	6
Tax positions from prior periods	**(4)**	(17)	31
Reductions due to settlements	**(2)**	—	—
Balance at end of year	**$ 31**	$ 32	$ 43

The tax positions from current periods for 2012 relate primarily to the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein 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 tax positions decrease from prior periods and the reductions due to settlements for 2012 relate to a settlement with the IRS of the calculation methodology for the production activities deduction.

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

	2012	2011	2010
		(in millions)	
Tax positions impacting the effective tax rate	**$ —**	$ 5	$ 6
Tax positions not impacting the effective tax rate	**31**	27	37
Balance of unrecognized tax benefits	**$ 31**	$ 32	$ 43

The tax positions not impacting the effective tax rate for 2012 relate to the timing difference associated with the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

Accrued interest for unrecognized tax benefits was as follows:

	2012	2011	2010
		(in millions)	
Interest accrued at beginning of year	**$ 1.9**	$ 1.5	$ 0.3
Interest reclassified due to settlements	**(1.9)**	—	—
Interest accrued during the year	**—**	0.4	1.2
Balance at end of year	**$ —**	$ 1.9	$ 1.5

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 12 months. The resolution of the tax accounting method change for repairs-generation assets, as well as the conclusion or settlement of state audits, could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has audited and closed all of Southern Company's consolidated federal income tax returns prior to 2009 and has settled its audits of Southern Company's consolidated federal income tax returns for 2009 and 2010, in principle, pending final approval. Additionally, the IRS has audited and closed Southern Company's 2011 consolidated federal income tax return. For tax years 2010 through 2013, Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2007.

Tax Method of Accounting for Repairs

Southern Company submitted a tax accounting method change related to the deductibility of repair costs associated with its subsidiaries' generation, transmission, and distribution systems effective for the 2009 consolidated federal income tax return in 2010. In August 2011, the IRS issued a revenue procedure, which provides a safe harbor method of accounting that taxpayers may use to determine eligible repair costs for transmission and distribution property. The IRS continues to work with the utility industry in an effort to define eligible repair costs for generation assets in a consistent manner for all utilities. The IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2014. The utility industry anticipates more detailed guidance concerning these regulations. Due to the uncertainty regarding the ultimate resolution of the repair costs for generation assets, an unrecognized tax position has been recorded for the tax accounting method change for repairs-generation assets. The ultimate outcome of this matter cannot be determined at this time; however, it is not expected to materially impact net income.

6. FINANCING

Long-Term Debt Payable to an Affiliated Trust

The Company has formed a wholly-owned trust subsidiary 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 as of December 31, 2012 and December 31, 2011, which constitute substantially all of the assets of this trust 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 trust's payment obligations with respect to these securities. At December 31, 2012 and 2011, trust preferred securities of $200 million were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for this trust and the related securities.

Securities Due Within One Year

At December 31, 2012 and 2011, the Company had scheduled maturities of senior notes due within one year totaling $250 million and $500 million, respectively.

Maturities of senior notes and pollution control revenue bonds through 2017 applicable to total long-term debt are as follows: $250 million in 2013; $454 million in 2015; $200 million in 2016; and $561 million in 2017. There are no scheduled maturities in 2014.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds or installment purchases of pollution control and 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 2012. In 2012, the Company redeemed approximately $0.7 million of The Industrial Development Board of the Town of West Jefferson Solid Waste Disposal Revenue Bonds (Alabama Power Company Miller Plant Project), Series 2008. The amount of tax-exempt pollution control revenue bonds outstanding at both December 31, 2012 and 2011 was $1.2 billion. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

Senior Notes

The Company issued a total of $1.0 billion of unsecured senior notes in 2012. The proceeds of these issuances were used for general corporate purposes, including the Company's continuous construction program, to redeem $450 million of unsecured senior notes in 2012, and to pay at maturity $500 million of unsecured senior notes in 2012.

At both December 31, 2012 and 2011, the Company had $4.8 billion of senior notes outstanding. These senior notes are effectively subordinated to all secured debt of the Company which amounted to approximately $153 million at December 31, 2012.

Preferred, Preference, and Common Stock

In 2012, the Company issued no new shares of preferred stock, 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 and 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.

The Company's preferred stock is subject to redemption at a price equal to the par value plus a premium. The Company's Class A preferred stock is subject to redemption at a price equal to the stated capital. Certain series of the Company's preference stock are subject to redemption at a price equal to the stated capital plus a make-whole premium based on the present value of the liquidation amount and future dividends to the first stated capital redemption date and the other series of preference stock are subject to redemption at a price equal to the stated capital. Certain series of the Company's preferred stock are subject to redemption at the option of the Company on or after a specified date. Information for each outstanding series is in the table below:

Preferred/Preference Stock	Par Value/ Stated Capital Per Share	Shares Outstanding	First Call Date	Redemption Price Per Share
4.92% Preferred Stock	$100	80,000	*	$103.23
4.72% Preferred Stock	$100	50,000	*	$102.18
4.64% Preferred Stock	$100	60,000	*	$103.14
4.60% Preferred Stock	$100	100,000	*	$104.20
4.52% Preferred Stock	$100	50,000	*	$102.93
4.20% Preferred Stock	$100	135,115	*	$105.00
5.83% Class A Preferred Stock	$25	1,520,000	8/1/2008	Stated Capital
5.20% Class A Preferred Stock	$25	6,480,000	8/1/2008	Stated Capital
5.30% Class A Preferred Stock	$25	4,000,000	4/1/2009	Stated Capital
5.625% Preference Stock	$25	6,000,000	1/1/2012	Stated Capital
6.450% Preference Stock	$25	6,000,000	*	**
6.500% Preference Stock	$25	2,000,000	*	**

* Redemption permitted any time after issuance

** Prior to 10/01/2017: Stated Value Plus Make-Whole Premium; after 10/01/2017: Stated Capital

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, 2012. 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

At December 31, 2012, committed credit arrangements with banks were as follows:

Expires[a]					Executable Term-Loans		Due Within One Year	
2013	2014	2016	Total	Unused	One Year	Two Years	Term Out	No Term Out
			(in millions)					
$ 158	$ 350	$ 800	$ 1,308	$ 1,308	$ 56	$ —	$ 56	$ 102

(a) No credit arrangements expire in 2015.

The Company expects to renew its credit agreements as needed, prior to expiration. Most of the credit arrangements require payment of a commitment fee based on the unused portion of the commitments or the maintenance of compensating balances with the banks. Commitment fees average less than 1/4 of 1% for the Company. Compensating balances are not legally restricted from withdrawal.

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, 2012, the Company was in compliance with the debt limit covenants.

In addition, the credit arrangements typically contain cross default provisions that are restricted to indebtedness (including guaranteed obligations) of the Company. The Company is currently in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowings.

A portion of the unused credit with banks is allocated to provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper program. During 2012, the Company remarketed $207 million of pollution control revenue bonds. The amount of variable rate pollution control revenue bonds requiring liquidity support was $793 million as of December 31, 2012.

The Company borrows through commercial paper programs that have the liquidity support of committed bank credit arrangements. The Company may also make short-term borrowings through various other arrangements with banks. At December 31, 2012 and 2011, there was no short-term debt outstanding. At December 31, 2012, the Company had regulatory approval to have outstanding up to $2.3 billion of short-term borrowings.

7. COMMITMENTS

Fuel and Purchased Power Agreements

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 which are not recognized on the balance sheets. In 2012, 2011, and 2010, the Company incurred fuel expense of $1.5 billion, $1.7 billion, and $1.9 billion, respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

In addition, the Company has entered into various long-term commitments for the purchase of capacity and electricity, some of which are accounted for as operating leases. Total expense under PPAs accounted for as operating leases was $33 million, $33 million, and $30 million for 2012, 2011, and 2010, respectively. Total estimated minimum long-term obligations at December 31, 2012 were as follows:

	Commitments Non-Affiliated *(in millions)*
2013	$ 31
2014	37
2015	38
2016	39
2017	40
2018 and thereafter	223
Total commitments	$ 408

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

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 credit rating of Southern Power is currently below that 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.

Operating Leases

The Company has entered into rental agreements for coal railcars, vehicles, and other equipment with various terms and expiration dates. Total rent expense was $24 million in 2012, $23 million in 2011, and $25 million in 2010. Of these amounts, $19 million, $18 million, and $20 million for 2012, 2011, and 2010, respectively, relate to the railcar leases and are recoverable through the Company's Rate ECR. As of December 31, 2012, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Railcars	Vehicles & Other	Total
	(in millions)		
2013	$ 16	$ 4	$ 20
2014	10	2	12
2015	8	—	8
2016	8	1	9
2017	4	—	4
2018 and thereafter	9	—	9
Total	$ 55	$ 7	$ 62

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. These leases have terms expiring through 2018 with maximum obligations under these leases of $21 million in 2013, $8 million in 2014, $5 million in 2015, $4 million in 2016, none in 2017, and $12 million in 2018 and thereafter. At the termination of the leases, the lessee may either exercise its purchase option, or the property can be sold to a third party. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligations.

Guarantees

At December 31, 2012, 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 Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2012, there were 1,057 current and former employees of the Company participating in the stock option program, and there were 39 million shares of Southern Company common stock remaining available for awards under the Omnibus Incentive Compensation Plan. 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 Omnibus Incentive Compensation Plan. For certain stock option awards, a change in control will provide accelerated vesting.

The estimated fair values of stock options granted 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	2012	2011	2010
Expected volatility	**17.7%**	17.5%	17.4%
Expected term *(in years)*	**5.0**	5.0	5.0
Interest rate	**0.9%**	2.3%	2.4%
Dividend yield	**4.2%**	4.8%	5.6%
Weighted average grant-date fair value	**$ 3.39**	$ 3.23	$ 2.23

The Company's activity in the stock option program for 2012 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2011	7,191,786	$ 33.63
Granted	1,099,315	44.44
Exercised	(2,226,269)	32.43
Cancelled	(4,280)	38.74
Outstanding at December 31, 2012	**6,060,552**	**$ 36.02**
Exercisable at December 31, 2012	**3,884,089**	**$ 33.84**

The number of stock options vested, and expected to vest in the future, as of December 31, 2012 was not significantly different from the number of stock options outstanding at December 31, 2012 as stated above. As of December 31, 2012, 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 $43 million and $35 million, respectively.

As of December 31, 2012, 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 11 months.

For the years ended December 31, 2012, 2011, and 2010, total compensation cost for stock option awards recognized in income was $4 million, $3 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, 2012, 2011, and 2010 was $28 million, $23 million, and $12 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $11 million, $9 million, and $4 million for the years ended December 31, 2012, 2011, and 2010, respectively.

Performance Shares

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

The fair value of performance share awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period. The Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. The expected volatility was based on the historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate 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 following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of performance share award units granted:

Year Ended December 31	**2012**	2011	2010
Expected volatility	**16.0%**	19.2%	20.7%
Expected term *(in years)*	**3.0**	3.0	3.0
Interest rate	**0.4%**	1.4%	1.4%
Annualized dividend rate	**$1.89**	$1.82	$1.75
Weighted average grant-date fair value	**$41.99**	$35.97	$30.13

Total unvested performance share units outstanding as of December 31, 2011 were 287,720. During 2012, 131,820 performance share units were granted, 134,054 performance share units were vested, and 4,950 performance share units were forfeited resulting in 280,536 unvested units outstanding at December 31, 2012. In January 2013, the vested performance share award units were converted into 180,997 shares outstanding at a share price of $43.05 for the three-year performance and vesting period ended December 31, 2012.

For the years ended December 31, 2012, 2011, and 2010, total compensation cost for performance share units recognized in income was $5 million, $3 million, and $1 million, respectively, with the related tax benefit also recognized in income of $2 million, $1 million, and $1 million, respectively. As of December 31, 2012, there was $5 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 11 months.

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 $2.25 billion for losses in excess of the $500 million primary coverage. This excess insurance is also provided by NEIL.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. The Company purchases the maximum limit allowed by NEIL 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. In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers, would be borne by the Company and could have a material effect on the Company's financial condition and results of operations.

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

10. FAIR VALUE MEASUREMENTS

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

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

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

As of December 31, 2012, 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, 2012:	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	$ —	$ 5	$ —	$ 5
Nuclear decommissioning trusts:[(a)]				
Domestic equity	291	64	—	355
Foreign equity	28	55	—	83
U.S. Treasury and government agency securities	—	29	—	29
Corporate bonds	—	101	—	101
Mortgage and asset backed securities	—	26	—	26
Other investments	—	10	—	10
Total	$ 319	$ 290	$ —	$ 609
Liabilities:				
Energy-related derivatives	$ —	$ 18	$ —	$ 18

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

As of December 31, 2011, 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, 2011:	**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:				
Nuclear decommissioning trusts:[(a)]				
Domestic equity	$ 253	$ 57	$ —	$ 310
Foreign equity	24	48	—	72
U.S. Treasury and government agency securities	17	8	—	25
Corporate bonds	—	93	—	93
Mortgage and asset backed securities	—	28	—	28
Other investments	—	11	—	11
Cash equivalents and restricted cash	209	—	—	209
Total	$ 503	$ 245	$ —	$ 748
Liabilities:				
Energy-related derivatives	$ —	$ 48	$ —	$ 48
Interest rate derivatives	—	18	—	18
Total	$ —	$ 66	$ —	$ 66

(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 (LIBOR) interest rates. Interest rate derivatives are also standard over-the-counter financial products valued using the market approach. Inputs for interest rate derivatives include LIBOR interest rates, interest rate futures contracts, and occasionally implied volatility of interest rate options. 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 evaluated by management in its 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, 2012 and 2011, 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:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
As of December 31, 2012:	*(in millions)*			
Nuclear decommissioning trusts:				
Equity-commingled funds	$55	None	Daily/Monthly	Daily/7 days
Trust-owned life insurance	96	None	Daily	15 days
As of December 31, 2011:				
Nuclear decommissioning trusts:				
Equity-commingled funds	$48	None	Daily/Monthly	Daily/7 days
Trust-owned life insurance	87	None	Daily	15 days
Cash equivalents and restricted cash:				
Money market funds	209	None	Daily	Not applicable

The nuclear decommissioning trust includes investments in 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 may 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, 2012 and 2011, 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:		
2012	**$6,179**	**$6,899**
2011	$6,132	$6,874

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates offered to the Company.

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 and are presented on a gross basis.

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, 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 energy 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, 2012, 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)		
57	2017	—

* mmBtu – million British thermal units

For cash flow hedges, the amounts expected to be reclassified from OCI to revenue and fuel expense for the 12-month period ending December 31, 2013 are immaterial.

Interest Rate Derivatives

The Company may also enter 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, 2012, there were no interest rate derivatives outstanding.

For the year ended December 31, 2012, the Company had realized net losses of $36 million upon termination of certain interest rate derivatives at the same time the related debt was issued. The effective portion of these losses has been deferred in OCI and is being amortized to interest expense over the life of the original interest rate derivative, reflecting the period in which the forecasted hedged transaction affects earnings.

The estimated pre-tax losses that will be reclassified from OCI to interest expense for the 12-month period ending December 31, 2013 are $3 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, 2012 and 2011, 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**	**2012**	2011	**Balance Sheet Location**	**2012**	2011
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	$ 2	$ —	Liabilities from risk management activities	$ 14	$ 36
	Other deferred charges and assets	3	—	Other deferred credits and liabilities	4	12
Total derivatives designated as hedging instruments for regulatory purposes		$ 5	$ —		$ 18	$ 48
Derivatives designated as hedging instruments in cash flow hedges						
Interest rate derivatives:	Other current assets	$ —	$ —	Liabilities from risk management activities	$ —	$ 18
Total		$ 5	$ —		$ 18	$ 66

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

At December 31, 2012 and 2011, 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**	**2012**	2011	**Balance Sheet Location**	**2012**	2011
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	$ (14)	$ (36)	Other current liabilities	$ 2	$ —
	Other regulatory assets, deferred	(4)	(12)	Other regulatory liabilities, deferred	3	—
Total energy-related derivative gains (losses)		$ (18)	$ (48)		$ 5	$ —

For the years ended December 31, 2012, 2011, and 2010, 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	**2012**	2011	2010	**Statements of Income Location**	**2012**	2011	2010
		(in millions)				*(in millions)*	
Interest rate derivatives	**$ (18)**	$ (14)	$ —	Interest expense, net of amounts capitalized	**$ (3)**	$3	$ 3

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

For the years ended December 31, 2012, 2011, and 2010, 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, 2012, the fair value of derivative liabilities with contingent features was $2 million.

At December 31, 2012, 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, were $15 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 2012 and 2011 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
		(in millions)	
March 2012	**$ 1,216**	**$ 291**	**$ 126**
June 2012	**1,377**	**390**	**185**
September 2012	**1,637**	**544**	**280**
December 2012	**1,290**	**271**	**113**
March 2011	$ 1,320	$ 329	$ 152
June 2011	1,440	404	190
September 2011	1,671	523	264
December 2011	1,271	258	102

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

SELECTED FINANCIAL AND OPERATING DATA 2008-2012
Alabama Power Company 2012 Annual Report

	2012	2011	2010	2009	2008
Operating Revenues (in millions)	$ 5,520	$ 5,702	$ 5,976	$ 5,529	$ 6,077
Net Income After Dividends on Preferred and Preference Stock (in millions)	$ 704	$ 708	$ 707	$ 670	$ 616
Cash Dividends on Common Stock (in millions)	$ 684	$ 774	$ 586	$ 523	$ 491
Return on Average Common Equity (percent)	13.10	13.19	13.31	13.27	13.30
Total Assets (in millions)	$ 18,712	$ 18,477	$ 17,994	$ 17,524	$ 16,536
Gross Property Additions (in millions)	$ 940	$ 1,016	$ 956	$ 1,323	$ 1,533
Capitalization (in millions):					
Common stock equity	$ 5,398	$ 5,342	$ 5,393	$ 5,237	$ 4,854
Preference stock	343	343	343	343	343
Redeemable preferred stock	342	342	342	342	342
Long-term debt	5,929	5,632	5,987	6,082	5,605
Total (excluding amounts due within one year)	$ 12,012	$ 11,659	$ 12,065	$ 12,004	$ 11,144
Capitalization Ratios (percent):					
Common stock equity	44.9	45.8	44.7	43.6	43.6
Preference stock	2.9	2.9	2.9	2.9	3.1
Redeemable preferred stock	2.8	2.9	2.8	2.8	3.0
Long-term debt	49.4	48.4	49.6	50.7	50.3
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	1,237,730	1,231,574	1,235,128	1,229,134	1,220,046
Commercial	196,177	196,270	197,336	198,642	211,119
Industrial	5,839	5,844	5,770	5,912	5,906
Other	748	746	782	780	775
Total	1,440,494	1,434,434	1,439,016	1,434,468	1,437,846
Employees (year-end)	6,778	6,632	6,552	6,842	6,997

SELECTED FINANCIAL AND OPERATING DATA 2008-2012 (continued)
Alabama Power Company 2012 Annual Report

	2012	2011	2010	2009	2008
Operating Revenues (in millions):					
Residential	**$ 2,068**	$ 2,144	$ 2,283	$ 1,962	$ 1,998
Commercial	**1,491**	1,495	1,535	1,430	1,459
Industrial	**1,346**	1,306	1,231	1,080	1,381
Other	**28**	27	27	25	24
Total retail	**4,933**	4,972	5,076	4,497	4,862
Wholesale — non-affiliates	**277**	287	465	620	712
Wholesale — affiliates	**111**	244	236	237	308
Total revenues from sales of electricity	**5,321**	5,503	5,777	5,354	5,882
Other revenues	**199**	199	199	175	195
Total	**$ 5,520**	$ 5,702	$ 5,976	$ 5,529	$ 6,077
Kilowatt-Hour Sales (in millions):					
Residential	**17,612**	18,650	20,417	18,071	18,380
Commercial	**13,963**	14,173	14,719	14,186	14,551
Industrial	**22,158**	21,666	20,622	18,555	22,075
Other	**214**	214	216	218	201
Total retail	**53,947**	54,703	55,974	51,030	55,207
Wholesale — non-affiliates	**4,196**	4,330	8,655	14,317	15,204
Wholesale — affiliates	**4,279**	7,211	6,074	6,473	5,256
Total	**62,422**	66,244	70,703	71,820	75,667
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**11.74**	11.50	11.18	10.86	10.87
Commercial	**10.68**	10.55	10.43	10.08	10.03
Industrial	**6.07**	6.03	5.97	5.82	6.26
Total retail	**9.14**	9.09	9.07	8.81	8.81
Wholesale	**4.58**	4.60	4.76	4.12	4.99
Total sales	**8.52**	8.31	8.17	7.45	7.77
Residential Average Annual Kilowatt-Hour Use Per Customer	**14,252**	15,138	16,570	14,716	15,162
Residential Average Annual Revenue Per Customer	**$ 1,674**	$ 1,740	$ 1,853	$ 1,597	$ 1,648
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**12,222**	12,222	12,222	12,222	12,222
Maximum Peak-Hour Demand (megawatts):					
Winter	**10,285**	11,553	11,349	10,701	10,747
Summer	**11,096**	11,500	11,488	10,870	11,518
Annual Load Factor (percent)	**61.3**	60.6	62.6	59.8	60.9
Plant Availability (percent)*:					
Fossil-steam	**88.6**	88.7	92.9	88.5	90.1
Nuclear	**94.5**	94.7	88.4	93.3	94.1
Source of Energy Supply (percent):					
Coal	**48.2**	52.5	56.6	53.4	58.5
Nuclear	**22.6**	20.8	17.7	18.6	17.8
Hydro	**4.1**	4.6	5.0	7.9	2.9
Gas	**16.8**	15.3	14.0	11.8	9.2
Purchased power —					
From non-affiliates	**2.0**	0.9	1.6	2.0	2.9
From affiliates	**6.3**	5.9	5.1	6.3	8.7
Total	**100.0**	100.0	100.0	100.0	100.0

* Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

DIRECTORS AND OFFICERS
Alabama Power Company 2012 Annual Report

Directors

Whit Armstrong
Managing Member
Creeke Capital Investments, LLC

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

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

Thomas A. Fanning
Chairman, President and CEO,
Southern Company

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

Patricia M. King
President,
Sunny King Automotive Group

James K. Lowder
Chairman,
The Colonial Company

Charles D. McCrary
President and CEO,
Alabama Power Company

Malcolm Portera
Retired Chancellor, The University of Alabama System

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

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.

Officers

Charles D. McCrary
President and Chief Executive Officer

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

Zeke W. Smith
Executive Vice President

Steve R. Spencer
Executive Vice President

Jim Heilbron[1]
Senior Vice President &
Senior Production Officer

Theodore J. McCullough[2]
Senior Vice President &
Senior Production Officer

Gordon G. Martin
Senior Vice President and
General Counsel

Greg Barker
Senior Vice President

Anita Allcorn-Walker
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

Mark S. Crews
Vice President

Daniel K. Glover
Vice President

R. Myrk Harkins
Vice President

John O. Hudson, III
Vice President

Richard O. Hutto
Vice President

Stacy R. Kilcoyne
Vice President

Barbara J. Knight
Vice President

Richard J. Mandes, Jr.[3]
Vice President

R. Scott Moore[4]
Vice President

Kenneth F. Novak
Vice President

Leigh Davis-Perry[5]
Vice President

Quentin P. Riggins
Vice President

Leslie L. Sanders
Vice President

R. Michael Saxon
Vice President

Don A. Scivley
Vice President

Julia H. Segars
Vice President

Nicholas C. Sellers
Vice President

Donna D. Smith
Vice President

Robert L. Weaver
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
Assistant Treasurer

1 **Effective 3/13**
2 **Resigned 3/13**
3 **Resigned 8/12**
4 **Elected 8/12**
5 **Resigned 7/12**

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 2012, retail energy sales accounted for 86 percent of the Company's total sales of 62 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 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
Computershare Shareowner Services, LLC
P.O. Box 43006
Providence, RI 02940-3006
(800) 554-7626

www.computershare.com/investor

Number of Preferred Shareholders of record as of December 31, 2012 was 1,564.

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) 257-4416.

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