

# ALABAMA POWER COMPANY

## 2013 ANNUAL REPORT



A SOUTHERN COMPANY



**MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING**  
**Alabama Power Company 2013 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 (1992)* 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, 2013.



Charles D. McCrary  
President and Chief Executive Officer



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

February 27, 2014

## 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, 2013 and 2012, 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, 2013. 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 27 to 74) present fairly, in all material respects, the financial position of Alabama Power Company as of December 31, 2013 and 2012, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America.

*Deloitte & Touche LLP*

Birmingham, Alabama  
February 27, 2014

## MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

### Alabama Power Company 2013 Annual Report

#### 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, reliability, 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 2013 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 2013 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 2013 results compared to its targets for some of these key indicators are reflected in the following chart:

<b>Key Performance Indicator</b>	<b>2013 Target Performance</b>	<b>2013 Actual Performance</b>
<b>Customer Satisfaction</b>	<b>Top quartile in customer surveys</b>	<b>Top quartile</b>
<b>Peak Season EFOR — fossil/hydro</b>	<b>5.86% or less</b>	<b>3.27%</b>
<b>Net Income After Dividends on Preferred and Preference Stock</b>	<b>\$694 million</b>	<b>\$712 million</b>

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance.

##### Earnings

The Company's 2013 net income after dividends on preferred and preference stock of \$712 million increased \$8 million (1.1%) from the prior year. The increase in net income was due primarily to more favorable weather-related revenues in 2013 compared to 2012, an increase in allowance for funds used during construction (AFUDC) resulting from increased capital expenditures, and a decrease in interest expense resulting from lower interest rates. The factors increasing net income were partially offset by a decrease in revenues related to net investment under rate certificated new plant environmental (Rate CNP Environmental) and a decrease in wholesale revenues to municipalities.

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.

**MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)**  
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**RESULTS OF OPERATIONS**

A condensed income statement for the Company follows:

	Amount		Increase (Decrease) from Prior Year	
	2013	2013	2013	2012
	<i>(in millions)</i>			
Operating revenues	\$ 5,618	\$ 98	\$	(182)
Fuel	1,631	128		(176)
Purchased power	229	(26)		(16)
Other operations and maintenance	1,289	2		25
Depreciation and amortization	645	6		2
Taxes other than income taxes	348	8		1
Total operating expenses	4,142	118		(164)
Operating income	1,476	(20)		(18)
Allowance for equity funds used during construction	32	13		(3)
Interest income	16	—		(2)
Interest expense, net of amounts capitalized	259	(28)		(12)
Other income (expense), net	(36)	(12)		6
Income taxes	478	1		(1)
Net income	751	8		(4)
Dividends on preferred and preference stock	39	—		—
Net income after dividends on preferred and preference stock	\$ 712	\$ 8	\$	(4)

**Operating Revenues**

Operating revenues for 2013 were \$5.6 billion, reflecting a \$98 million increase from 2012. Details of operating revenues were as follows:

	Amount	
	2013	2012
	<i>(in millions)</i>	
Retail — prior year	\$ 4,933	\$ 4,972
Estimated change resulting from —		
Rates and pricing	(18)	69
Sales growth	4	61
Weather	21	(115)
Fuel and other cost recovery	12	(54)
Retail — current year	4,952	4,933
Wholesale revenues —		
Non-affiliates	248	277
Affiliates	212	111
Total wholesale revenues	460	388
Other operating revenues	206	199
Total operating revenues	\$ 5,618	\$ 5,520
Percent change	1.8%	(3.2)%

Retail revenues in 2013 were \$5.0 billion. These revenues increased \$19 million (0.4%) in 2013 and decreased \$39 million (0.8%) in 2012, each as compared to the prior year. The increase in 2013 was due to more favorable weather, increased fuel revenues and

**MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)**  
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increased revenues associated with rate certificated new plant (Rate CNP PPA). The increase in 2013 was partially offset by a reduction in revenues related to net investments under Rate CNP Environmental. The decrease in 2012 was due to milder weather, a reduction in revenues related to net investments under Rate CNP Environmental, and a reduction in fuel revenues when compared to 2011. The decrease in 2012 was 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. 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 – Retail Energy Cost Recovery" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Retail Energy Cost Recovery" for additional information.

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

	2013	2012	2011
	<i>(in millions)</i>		
Capacity and other	\$ 128	\$ 143	\$ 148
Energy	120	134	139
<b>Total non-affiliated</b>	<b>\$ 248</b>	<b>\$ 277</b>	<b>\$ 287</b>

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 2013, wholesale revenues from sales to non-affiliates decreased \$29 million (10.5%) reflecting a \$15 million decrease in capacity revenues and a \$14 million decrease in revenues from energy sales. In 2013, kilowatt-hour (KWH) sales decreased 11.3% primarily from decreased sales to municipalities, partially offset by an 0.8% increase in the price of energy. 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. In 2012, the price of energy decreased 5.2%, partially offset by a 1.8% increase in KWH sales. 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.

Wholesale revenues from sales to affiliated companies will vary depending on demand and the availability and cost of generating resources at each company. These affiliate 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 2013, wholesale revenues from sales to affiliates increased \$101 million (91.0%) primarily due to a \$103 million increase in energy sales, partially offset by a \$2 million decrease in capacity revenues. In 2013, KWH sales increased 88.9% and there was a 1.3% increase in the price of energy. 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. In 2012, KWH sales decreased 45% and there was a 17.6% decrease in the price of energy.

In 2013, other operating revenues were \$206 million compared to \$199 million in 2012. The increase 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 2013 and the percent change by year were as follows:

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	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2013	2013	2012	2013	2012
	<i>(in billions)</i>				
Residential	17.9	1.7%	(5.6)%	(1.1)%	2.6%
Commercial	13.9	(0.5)	(1.5)	0.5	0.6
Industrial	22.9	3.4	2.3	3.4	2.3
Other	0.2	(1.4)	—	(1.4)	—
Total retail	54.9	1.8	(1.4)	1.1 %	1.9%
Wholesale —					
Non-affiliates	4.1	(10.8)	0.6		
Affiliates	7.3	88.9	(44.9)		
Total wholesale	11.4	34.5	(26.9)		
Total energy sales	66.3	6.3%	(5.9)%		

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 2013 were 1.8% more than in 2012. Residential sales increased 1.7%, due primarily to more favorable weather in 2013. Weather-adjusted residential sales decreased 1.1%, primarily due to a decrease in customer demand. Commercial sales and weather-adjusted commercial sales remained relatively flat in 2013. Industrial sales increased 3.4% in 2013 as a result of an increase in demand resulting from changes in production levels primarily in the chemicals, the primary metals, and the stone, clay, and glass sectors.

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.

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.

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

	2013	2012	2011
Total generation ( <i>billions of KWHs</i> )	<b>65.3</b>	59.9	64.8
Total purchased power ( <i>billions of KWHs</i> )	<b>4.0</b>	5.4	4.7
Sources of generation ( <i>percent</i> ) —			
Coal	<b>53</b>	53	56
Nuclear	<b>21</b>	25	22
Gas	<b>17</b>	18	17
Hydro	<b>9</b>	4	5
Cost of fuel, generated ( <i>cents per net KWH</i> ) —			
Coal	<b>3.29</b>	3.30	3.16
Nuclear	<b>0.84</b>	0.80	0.66
Gas	<b>3.38</b>	3.06	3.92
Average cost of fuel, generated ( <i>cents per net KWH</i> )*	<b>2.73</b>	2.61	2.70
Average cost of purchased power ( <i>cents per net KWH</i> )**	<b>5.76</b>	4.86	6.04

\* 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 \$1.9 billion in 2013, an increase of \$102 million (5.8%) compared to 2012. The increase was primarily due to a \$95 million increase in the volume of KWHs generated, a \$38 million increase in the average cost of fuel, and a \$37 million increase in the average cost of purchased power. These increases were partially offset by a \$68 million decrease related to the volume of KWHs purchased.

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 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 – Retail Energy Cost Recovery" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Retail Energy Cost Recovery" for additional information.

*Fuel*

Fuel expenses were \$1.6 billion in 2013, an increase of \$128 million (8.5%) compared to 2012. This increase was primarily due to a 10.5% increase in the average cost of KWHs generated by natural gas, which excludes tolling agreements, and a 9.9% increase in KWHs generated by coal. This was partially offset by a 110.9% increase in the volume of KWHs generated by hydro facilities resulting from greater rainfall. 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.

*Purchased Power – Non-Affiliates*

In 2013, purchased power expense from non-affiliates was \$100 million, an increase of \$27 million (37.0%) compared to 2012. The increase over the prior year was primarily due to a 52.6% increase in the amount of energy purchased, partially offset by a 17.2% decrease in the average cost per KWH. In 2012 and 2011, purchased power expense from non-affiliates was \$73 million.

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.

**MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)**  
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*Purchased Power – Affiliates*

Purchased power expense from affiliates was \$129 million in 2013, a decrease of \$53 million (29.1%) compared to 2012. This decrease was primarily due to a 50.4% decrease in the amount of energy purchased, partially offset by a 42.5% increase in the average cost per KWH. Purchased power expense 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.

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 2013, other operations and maintenance expenses increased \$2 million (0.22%) as compared to the prior year. The increase was not material.

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

***Depreciation and Amortization***

Depreciation and amortization increased \$6 million (0.9%) in 2013 and \$2 million (0.3%) in 2012, each as compared to the prior year. The increase in 2013 was primarily due to an increase in depreciation related to environmental assets, additions to property, plant, and equipment related to distribution and transmission projects, as well as the amortization of software. The increase related to environmental assets was offset by revenues under Rate CNP Environmental. These increases were partially offset by the deferral of certain expenses under an accounting order. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Compliance and Pension Cost Accounting Order" herein and Note 3 to the financial statements under "Compliance and Pension Cost Accounting Order" for additional information. The increase in 2012 was not material.

***Taxes Other Than Income Taxes***

Taxes other than income taxes increased \$8 million (2.4%) in 2013 and \$1 million (0.3%) in 2012, each as compared to the prior year. The increase in 2013 was primarily due to property taxes, state use tax, and increases in municipal public utility license tax bases. The increase in 2012 was not material.

***Allowance for Funds Used During Construction Equity***

AFUDC equity increased \$13 million (68.4%) in 2013 as compared to the prior year primarily due to increased capital expenditures associated with environmental, steam and nuclear generating facilities, and transmission. 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. 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 \$28 million (9.8%) in 2013 and \$12 million (4.0%) in 2012, each as compared to the prior year. The decreases in 2013 and 2012 were primarily due to a decrease in interest rates and the timing of issuances and redemptions of long-term debt.

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***Other Income (Expense), Net***

Other income (expense), net decreased \$12 million (50.0%) in 2013 as compared to the prior year primarily due to increases in donations, partially offset by increases in non-operating income related to gains on sales of non-utility property. 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.

**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 other 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 regional and global economic conditions impact sales for the Company, as 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***

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the U.S. Environmental Protection Agency (EPA) brought civil enforcement actions in federal district court against the Company alleging violations of the New Source Review (NSR) provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by Mississippi Power. These civil actions seek penalties and injunctive relief, including orders requiring installation of the best available control technologies at the affected units. The case against the Company (including claims involving a unit co-owned by Mississippi Power) has been actively litigated in the U.S. District Court for the Northern District of Alabama, resulting in a settlement in 2006 of the alleged NSR violations at Plant Miller; voluntary dismissal of certain claims by the EPA; and a grant of summary judgment for the Company on all remaining claims and dismissal of the case with prejudice in 2011. On September 19, 2013, the U.S. Court of Appeals for the Eleventh Circuit affirmed in part and reversed in part the 2011 judgment in favor of the Company, and the case has been transferred back to the U.S. District Court for the Northern District of Alabama for further proceedings.

## **MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)**

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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.

#### ***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 2013, the Company had invested approximately \$3.2 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately \$184 million, \$62 million, and \$34 million for 2013, 2012, and 2011, respectively. The Company expects that base level capital expenditures to comply with existing statutes and regulations will total approximately \$1.1 billion from 2014 through 2016, with annual totals of approximately \$502 million, \$443 million, and \$166 million for 2014, 2015, and 2016, respectively.

The Company continues to monitor the development of the EPA's proposed water and coal combustion residuals 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 residuals rules for 2014 through 2016. The ultimate capital expenditures and compliance costs with respect to these proposed rules, including additional expenditures required after 2016, 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 Residuals" 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). If such compliance 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 financial statements for additional information.

Compliance with any new federal or state legislation or regulations relating to air quality, water, coal combustion residuals, 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.

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The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone National Ambient Air Quality Standard (NAAQS). In 2008, the EPA adopted a more stringent eight-hour ozone NAAQS, which it began to implement in 2011. In May 2012, the EPA published its final determination of nonattainment areas based on the 2008 eight-hour ozone NAAQS. All areas within the Company's service territory have achieved attainment 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 NAAQS, and the EPA has officially redesignated some former nonattainment areas within the service territory as attainment for these 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 NAAQS for sulfur dioxide (SO<sub>2</sub>), which established a new one-hour standard, became effective in 2010. No areas within the Company's service territory have been designated as nonattainment under this rule. However, the EPA may designate additional areas as nonattainment in the future, which could include areas within the Company's service territory. Implementation of the revised SO<sub>2</sub> standard could require additional reductions in SO<sub>2</sub> emissions and increased compliance and operational costs.

On February 13, 2014, the EPA proposed to delete from the Alabama State Implementation Plan (SIP) the Alabama opacity rule that the EPA approved in 2008, which provides operational flexibility to affected units. On March 6, 2013, the U.S. Court of Appeals for the Eleventh Circuit ruled in favor of the Company and vacated an earlier attempt by the EPA to rescind its 2008 approval. The EPA's latest proposal characterizes the proposed deletion as an error correction within the meaning of the Clean Air Act. The Company believes this interpretation of the Clean Air Act to be incorrect. If finalized, this proposed action could affect unit availability and result in increased operations and maintenance costs for affected units, including units co-owned by Mississippi Power and units owned by SEGCO.

The Company's service territory is subject to the requirements of the Clean Air Interstate Rule (CAIR), which calls for phased reductions in SO<sub>2</sub> and nitrogen oxide (NO<sub>x</sub>) 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 2011, the EPA promulgated the Cross State Air Pollution Rule (CSAPR) to replace CAIR. However, in August 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR in its entirety and directed the EPA to continue to administer CAIR pending the EPA's development of a valid replacement. Review of the U.S. Court of Appeals for the District of Columbia Circuit's decision regarding CSAPR is currently pending before the U.S. Supreme Court.

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 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 February 2012, the EPA finalized the Mercury and Air Toxics Standards (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; however, states may authorize a compliance extension of up to one year to April 16, 2016.

In August 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. The EPA has entered into a settlement agreement requiring it to finalize the rule by June 12, 2014.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the current and proposed 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.

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The impacts of the eight-hour ozone, fine particulate matter and SO<sub>2</sub> NAAQS, the Alabama opacity rule, 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 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 is required to issue a final rule by April 17, 2014.

On June 7, 2013, the EPA published a proposed rule which requested comments on a range of potential regulatory options for addressing certain wastestreams from steam electric power plants. These regulations could result in the installation of additional controls at certain of the facilities of the Company, which could result in significant capital expenditures and compliance costs that could affect future unit retirement and replacement decisions, depending on the specific technology requirements of the final rule. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" for additional information regarding estimated compliance costs for 2014 through 2016.

The impact of these proposed rules cannot be determined at this time and will depend on the specific provisions of the final rules and the outcome of any legal challenges. These regulations could result in 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. 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.

*Coal Combustion Residuals*

The Company currently operates six electric generating plants with on-site coal combustion residuals storage facilities. In addition to on-site storage, the Company also sells a portion of its coal combustion residuals to third parties for beneficial reuse. Historically, individual states have regulated coal combustion residuals and the State of Alabama has its own regulatory requirements. 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 residuals, 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 residuals: 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 residuals 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 residuals. On September 30, 2013, the U.S. District Court for the District of Columbia issued an order granting partial summary judgment to the environmental groups and other parties, ruling that the EPA has a statutory obligation to review and revise, as necessary, the federal solid waste regulations applicable to coal combustion residuals. On January 29, 2014, the EPA filed a consent decree requiring the EPA to take final action regarding the proposed regulation of coal combustion residuals as solid waste by December 19, 2014.

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 residuals could have a material impact on the generation, management, beneficial use, and disposal of such residuals. 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

## **MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)**

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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 2014 through 2016.

#### ***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. The legal basis for these regulations is currently being challenged in the U.S. Supreme Court. 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 January 8, 2014, the EPA published re-proposed regulations to establish standards of performance for greenhouse gas emissions from new fossil fuel steam electric generating units. A Presidential memorandum issued on June 25, 2013 also directs the EPA to propose standards, regulations, or guidelines for addressing modified, reconstructed, and existing steam electric generating units by June 1, 2014.

Although the outcome of any federal, state, and international initiatives, including the EPA's proposed regulations and guidelines discussed above, will depend on the scope and specific requirements of the proposed and final rules and the outcome of any legal challenges and, therefore, 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 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's 2012 greenhouse gas emissions were approximately 37 million metric tons of carbon dioxide equivalent. The preliminary estimate of the Company's 2013 greenhouse gas emissions on the same basis is approximately 41 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 and other factors.

#### **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. In 2010, the FERC issued a new 30-year license to the Company for the Warrior River developments. On March 18, 2013, following the FERC's denials of their requests for rehearing, the Smith Lake Improvement and Stakeholders' Association filed an appeal to the U.S. Court of Appeals for the District of Columbia Circuit regarding the FERC's orders related to the Warrior River relicensing proceedings.

On June 20, 2013, the FERC entered an order granting the Company's application for relicensing of the Company's seven hydroelectric developments on the Coosa River for 30 years. On July 22, 2013, the Company filed a petition requesting rehearing of the FERC order granting the relicense seeking revisions to several conditions of the license. The Alabama Rivers Alliance, American Rivers, the Georgia Environmental Protection Division, and the Atlanta Regional Commission have also filed petitions for rehearing of the FERC order.

In 2011, the Company filed an application with the FERC to relicense the Martin Dam Project. The current Martin license expired on June 8, 2013. Since the FERC did not act on the Company's licenses application prior to the expiration of the existing license, the FERC issued an annual license to the Company for the Martin Dam Project on June 18, 2013.

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On August 16, 2013, the Company filed an application with the FERC to relicense the Holt Hydroelectric Project. The current Holt license will expire on August 31, 2015.

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 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 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%. If the Company's actual retail return is above the allowed equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail return fall below the allowed equity return range. Prior to 2014, retail rates remained unchanged when the retail return on common equity (ROE) was projected to be between 13.0% and 14.5%.

During 2013, the Alabama PSC held public proceedings regarding the operation and utilization of Rate RSE. On August 13, 2013 the Alabama PSC voted to issue a report on Rate RSE that found that the Company's Rate RSE mechanism continues to be just and reasonable to customers and the Company, but recommended the Company modify Rate RSE as follows:

- Eliminate the provision of Rate RSE establishing an allowed range of ROE.
- Eliminate the provision of Rate RSE limiting the Company's capital structure to an allowed equity ratio of 45%.
- Replace these two provisions with a provision that establishes rates based upon an allowed weighted cost of equity (WCE) range of 5.75% to 6.21%, with an adjusting point of 5.98%. If calculated under the previous Rate RSE provisions, the resulting WCE would range from 5.85% to 6.53%, with an adjusting point of 6.19%.
- Provide eligibility for a performance-based adder of seven basis points, or 0.07%, to the WCE adjusting point if the Company (i) has an "A" credit rating equivalent with at least one of the recognized rating agencies or (ii) is in the top one-third of a designated customer value benchmark survey.

Substantially all other provisions of Rate RSE were unchanged.

On August 21, 2013, the Company filed its consent to these recommendations with the Alabama PSC. The changes became effective for calendar year 2014. On November 27, 2013, the Company made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2014; projected earnings were within the specified WCE range and, therefore, retail rates under Rate RSE remained unchanged for 2014. In 2012 and 2013, retail rates under Rate RSE remained unchanged from 2011. Under the terms of Rate RSE, the maximum possible increase for 2015 is 5.00%.

***Rate CNP***

The Company's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service under rate certificated new plant (Rate CNP). The Company may also recover retail costs associated with certificated PPAs under Rate CNP PPA. There was no adjustment to Rate CNP PPA in 2012. On March 5, 2013, 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, 2013 through March 31, 2014. It is anticipated that no adjustment will be made to Rate CNP PPA in 2014. As of December 31, 2013, the Company had an under recovered certificated PPA balance of \$18 million, all of which is included in deferred under recovered regulatory clause revenues in the balance sheet.

In 2011, the Alabama PSC approved and certificated a PPA of approximately 200 megawatts (MWs) of energy from wind-powered generating facilities which became operational in December 2012. In September 2012, the Alabama PSC approved and

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certificated a second wind PPA of approximately 200 MWs which became operational in January 2014. The terms of the wind PPAs 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. The Company has elected the normal purchase normal sale (NPNS) scope exception under the derivative accounting rules for its two wind PPAs, which total approximately 400 MWs. The NPNS exception allows the PPAs to be recorded at a cost, rather than fair value, basis. The industry's application of the NPNS exception to certain physical forward transactions in nodal markets is currently under review by the U.S. Securities and Exchange Commission (SEC) at the request of the electric utility industry. The outcome of the SEC's review cannot now be determined. If the Company is ultimately required to record these PPAs at fair value, an offsetting regulatory asset or regulatory liability will be recorded.

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 in 2012 or 2013. On August 13, 2013, the Alabama PSC approved the Company's petition requesting a revision to Rate CNP Environmental that allows recovery of costs related to pre-2005 environmental assets previously being recovered through Rate RSE. The revenue impact as a result of this revision is estimated to be \$58 million in 2014. On November 21, 2013, 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 approximately \$72 million, which is to be recovered in the billing months of January 2014 through December 2014. On December 3, 2013, the Alabama PSC issued a consent order that the Company leave in effect for 2014 the factors associated with the Company's environmental compliance costs for the year 2013. Any unrecovered amounts associated with 2014 will be reflected in the 2015 filing. As of December 31, 2013, the Company had an under recovered environmental clause balance of \$7 million which is included in deferred under recovered regulatory clause revenues in the balance sheet.

***Environmental Accounting Order***

Based on an order from the Alabama PSC, the Company is allowed to establish a regulatory asset to record the unrecovered investment costs, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure associated with future unit retirements caused by environmental regulations. 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***

In November 2012, the Alabama PSC approved an accounting order to defer to a regulatory asset account certain compliance-related operations and maintenance expenditures for the years 2013 through 2017, as well as the incremental increase in operations expense related to pension cost for 2013. These deferred costs are to be amortized over a three-year period beginning in January 2015. The compliance related expenditures were related to (i) standards addressing Critical Infrastructure Protection issued by the North American Electric Reliability Corporation, (ii) cyber security requirements issued by the U.S. Nuclear Regulatory Commission (NRC), and (iii) NRC guidance addressing the readiness at nuclear facilities within the U.S. for severe events. The compliance-related expenses to be afforded regulatory asset treatment over the five-year period are currently estimated to be approximately \$37 million. The amount of operations and maintenance expenses deferred to a regulatory asset in 2013 associated with compliance-related expenditures and pension cost was approximately \$8 million and \$12 million, respectively. Pursuant to the accounting order, the Company has the ability to accelerate the amortization of the regulatory assets with notification to the Alabama PSC. See "Other Matters" herein for information regarding NRC actions as a result of the earthquake and tsunami that struck Japan in 2011.

***Retail 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 3, 2013, the Alabama PSC issued a consent order that the Company leave in effect the energy cost recovery rates which began in April 2011 for 2014. Therefore, the Rate ECR factor as

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of January 1, 2014 remained at 2.681 cents per KWH. Effective with billings beginning in January 2015, the Rate ECR factor will be 5.910 cents per KWH, absent a further order from the Alabama PSC.

The Company's over recovered fuel costs at December 31, 2013 totaled \$42 million as compared to under recovered fuel costs of \$4 million at December 31, 2012. At December 31, 2013, \$27 million is included in other regulatory liabilities, current and \$15 million is included in deferred over recovered regulatory clause revenues. The under recovered fuel costs at December 31, 2012 are included in deferred under recovered regulatory clause revenues. These classifications are based on estimates, which include such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any 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.

In accordance with the order that was issued by the Alabama PSC in 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, 2013 and December 31, 2012 were approximately \$96 million and \$103 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 accordance with a 2010 Alabama PSC order, nuclear outage operations and maintenance expenses for the two units at Plant Farley are deferred to a regulatory asset when the charges actually occur and are then amortized over the subsequent 18-month operational cycle.

Approximately \$31 million of nuclear outage costs from the spring of 2012 was amortized to nuclear operations and maintenance expenses over the 18-month period ended in December 2013. During the spring of 2013, approximately \$28 million of nuclear outage costs was deferred to a regulatory asset, and beginning in July 2013, these deferred costs are being amortized over an 18-month period. During the fall of 2013, approximately \$32 million of nuclear outage costs associated with the second unit was deferred to a regulatory asset, and beginning in January 2014, these deferred costs are being amortized 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 Alabama PSC order.

***Non-Nuclear Outage Accounting Order***

On August 13, 2013, the Alabama PSC approved the Company's petition requesting authorization to defer to a regulatory asset account certain operations and maintenance expenses associated with planned outages at non-nuclear generation facilities in 2014 and to amortize those expenses over a three-year period beginning in 2015. The 2014 outage expenditures to be deferred and amortized are estimated to total approximately \$78 million.

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**Income Tax Matters**

***Bonus Depreciation***

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 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 had a positive impact on the Company's cash flows of approximately \$74 million in 2013 and is expected to have a positive impact between \$40 million and \$45 million on the Company's 2014 cash flows.

**Other Matters**

In accordance with accounting standards related to employers' accounting for pensions, the Company recorded pension costs of \$47 million in 2013 and \$6 million in 2012 and recorded non-cash pre-tax pension income of \$21 million in 2011. Postretirement benefit costs for the Company were \$7 million, \$10 million, and \$11 million in 2013, 2012, and 2011, 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 residuals, 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 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. In addition, the NRC has issued a series of orders requiring safety-related changes to U.S. nuclear facilities and expects to issue orders in the future requiring additional upgrades. 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.

Additionally, there are 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.

On November 19, 2013, the U.S. District Court for the District of Columbia ordered the DOE to cease collecting spent fuel depository fees from nuclear power plant operators until such time as the DOE either complies with the Nuclear Waste Policy Act of 1982 or until the U.S. Congress enacts an alternative waste management plan. In accordance with the court's order, the DOE has submitted a proposal to the U.S. Congress to change the fee to zero. That proposal is pending before the U.S. Congress and will become effective after 90 days of legislative session from the time of submittal unless the U.S. Congress enacts legislation that impacts the proposed fee change. The DOE's petition for rehearing of the November 2013 decision is currently pending and the Company is continuing to pay the fee of approximately \$13 million annually. The ultimate outcome of this matter 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, asset retirement obligations, 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, 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. 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 \$6 million or less change in total annual benefit expense and an \$82 million or less change in projected obligations.

**MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)**  
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**FINANCIAL CONDITION AND LIQUIDITY**

**Overview**

The Company's financial condition remained stable at December 31, 2013. 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 2014 through 2016, 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 maintain existing generation facilities, 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, 2013 as compared to December 31, 2012. No contributions to the qualified pension plan were made for the year ended December 31, 2013. 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 2018.

Net cash provided from operating activities totaled \$1.9 billion for 2013, an increase of \$538 million as compared to 2012. The increase in cash provided from operating activities was primarily due to changes in timing of fossil fuel stock purchases and payment of accounts payable, and collection of fuel cost recovery revenues. 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 used for investing activities totaled \$1.1 billion for 2013, \$0.9 billion for 2012, and \$1.0 billion for 2011. In 2013, these additions were primarily due to gross property additions related to steam generation, distribution, and transmission equipment. 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 \$614 million in 2013 primarily due to the payment of common stock dividends, and the issuance and a maturity of senior notes. 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. 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 2013 include an increase of \$620 million in property, plant, and equipment primarily due to additions to steam, distribution, and transmission facilities. Other significant changes include an increase of \$276 million in prepaid pension costs and a decrease of \$391 million in other regulatory assets, deferred, both of which are primarily attributable to a positive return on assets and an increase in the discount rate associated with retirement benefit plans.

The Company's ratio of common equity to total capitalization, including short-term debt, was 44.3% in 2013 and 44.0% in 2012. 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 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.

**MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)**  
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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, 2013, the Company had approximately \$295 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2013 were as follows:

Expires <sup>(a)</sup>					Executable Term-Loans		Due Within One Year	
2014	2015	2018	Total	Unused	One Year	Two Years	Term Out	Not Term Out
<i>(in millions)</i>								
\$ 238	\$ 35	\$ 1,030	\$ 1,303	\$ 1,303	\$ 53	\$ —	\$ 53	\$ 185

(a) No credit arrangements expire in 2016 or 2017.

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 to other indebtedness (including guarantee obligations) of the Company. Such cross default provisions to other indebtedness would trigger an event of default if the Company defaulted on indebtedness or guarantee obligations over a specified threshold. The Company is currently in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowings. 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. 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 borrowings. As of December 31, 2013, the Company had \$793 million of outstanding variable rate pollution control revenue bonds requiring liquidity support. In addition, at December 31, 2013, the Company had \$200 million of fixed rate pollution control revenue bonds that will be required to be remarketed within the next 12 months.

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 <sup>(a)</sup>		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
<i>(in millions)</i>					
<b>December 31, 2013:</b>					
Commercial paper	\$—	—%	\$11	0.2%	\$90
<b>December 31, 2012:</b>					
Commercial paper	\$—	—%	\$6	0.2%	\$57
<b>December 31, 2011:</b>					
Commercial paper	\$—	—%	\$20	0.2%	\$255

(a) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2013, 2012, and 2011.

Management believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and cash.

**MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)**  
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**Financing Activities**

In November 2013, the Company's \$250 million aggregate principal amount of its Series 2008B 5.80% Senior Notes due November 15, 2013 matured.

In December 2013, the Company issued \$300 million aggregate principal amount of its Series 2013A 3.55% Senior Notes due December 1, 2023. The proceeds were used for general corporate purposes, including the Company's continuous construction program.

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

**Credit Rating Risk**

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to 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, 2013, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately \$268 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.

On May 24, 2013, Standard and Poor's Rating Services, a division of the McGraw Hill Companies Inc. (S&P), revised the ratings outlook for Southern Company and the traditional operating companies, including the Company, from stable to negative.

On January 31, 2014, Moody's Investors Service, Inc. (Moody's) upgraded the senior unsecured debt and preferred stock ratings of the Company to A1 from A2 and A3 from Baa1, respectively. Moody's maintained the stable ratings outlook for the Company.

**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, 2014 was 0.72%. 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, 2014. 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, 2013 when compared to the December 31, 2012 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.

**MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)**  
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The changes in fair value of energy-related derivative contracts are substantially attributable to both the volume and the price of natural gas. For the years ended December 31, the changes in fair value of energy-related derivative contracts, the majority of which are composed of regulatory hedges, were as follows:

	<b>2013 Changes</b>	<b>2012 Changes</b>
	Fair Value	
	<i>(in millions)</i>	
Contracts outstanding at the beginning of the period, assets (liabilities), net	\$ (13)	\$ (48)
Contracts realized or settled	10	46
Current period changes <sup>(a)</sup>	2	(11)
Contracts outstanding at the end of the period, assets (liabilities), net	\$ (1)	\$ (13)

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

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

	<b>2013</b>	<b>2012</b>
	mmBtu* Volume	
	<i>(in millions)</i>	
Commodity – Natural gas swaps	64	45
Commodity – Natural gas options	5	12
Total hedge volume	69	57

\* million British thermal units (mmBtu)

The weighted average swap contract cost above market prices was approximately \$0.02 per mmBtu as of December 31, 2013 and \$0.30 per mmBtu as of December 31, 2012. 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, 2013 and 2012, 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, 2013 were as follows:

	<b>Fair Value Measurements</b>		
	<b>December 31, 2013</b>		
	Total	Maturity	
	Fair Value	Year 1	Years 2&3
	<i>(in millions)</i>		
Level 1	\$ —	\$ —	\$ —
Level 2	(1)	2	(3)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	\$ (1)	\$ 2	\$ (3)

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

**MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)**  
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grade credit ratings by Moody's and S&P, or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements.

**Capital Requirements and Contractual Obligations**

The Company's construction program consists of a base level capital investment and capital expenditures to comply with existing environmental statutes and regulations. Over the next three years, the Company estimates spending, as part of its base level capital investment, \$575 million on Plant Farley (including nuclear fuel), \$930 million on distribution facilities, and \$654 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 residuals 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 residuals rules over the 2014 through 2016 three-year period, based on the assumption that coal combustion residuals will continue to be regulated as non-hazardous solid waste under the proposed rule, are estimated as follows:

	2014	2015	2016
<b>Construction program:</b>	<i>(in millions)</i>		
Base capital	\$ 1,229	\$ 1,210	\$ 911
Existing environmental statutes and regulations	502	443	166
<b>Total construction program base level capital investment</b>	<b>\$ 1,731</b>	<b>\$ 1,653</b>	<b>\$ 1,077</b>
<b>Potential incremental environmental compliance investments:</b>			
Proposed water and coal combustion residuals rules	\$ 3	\$ 9	\$ 143

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 \$654 million will be required by the end of 2016 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, 6, 7, and 11 to the financial statements for additional information.

**MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)**  
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**Contractual Obligations**

	2014	2015- 2016	2017- 2018	After 2018	Total
	<i>(in millions)</i>				
Long-term debt <sup>(a)</sup> —					
Principal	\$ —	\$ 654	\$ 561	\$ 5,018	\$ 6,233
Interest	243	484	431	3,225	4,383
Preferred and preference stock dividends <sup>(b)</sup>	39	79	79	—	197
Financial derivative obligations <sup>(c)</sup>	3	5	—	—	8
Operating leases <sup>(d)</sup>	15	24	10	15	64
Capital Lease	—	1	1	3	5
Purchase commitments —					
Capital <sup>(e)</sup>	1,590	2,563	—	—	4,153
Fuel <sup>(f)</sup>	1,351	1,787	854	804	4,796
Purchased power <sup>(g)</sup>	58	121	128	570	877
Other <sup>(h)</sup>	45	63	45	14	167
Pension and other postretirement benefit plans <sup>(i)</sup>	17	33	—	—	50
<b>Total</b>	<b>\$ 3,361</b>	<b>\$ 5,814</b>	<b>\$ 2,109</b>	<b>\$ 9,649</b>	<b>\$ 20,933</b>

(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, 2014, 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) Excludes PPAs that are accounted for as leases and are included in purchased power.

(e) The Company provides estimated capital expenditures for a three-year period, including capital expenditures and compliance costs associated with existing environmental regulations. Such amounts exclude the Company's estimates of potential incremental environmental compliance investment to comply with proposed water and coal combustion residuals rules, which are approximately \$3 million, \$9 million, and \$143 million for 2014, 2015, and 2016, 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, 2013, 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, 2013.

(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.

**MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)**  
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**Cautionary Statement Regarding Forward Looking Statements**

The Company's 2013 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 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 residuals, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including FERC matters, 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, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, 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, to construct facilities in accordance with the requirements of permits and licenses, and to satisfy any operational and environmental performance standards;
- investment performance of the Company's employee and retiree 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, tornadoes, hurricanes, droughts, pandemic health events such as influenzas, or other similar occurrences;

**MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)**  
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- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

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

**STATEMENTS OF INCOME**  
**For the Years Ended December 31, 2013, 2012, and 2011**  
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	2013	2012	2011
	<i>(in millions)</i>		
<b>Operating Revenues:</b>			
Retail revenues	\$ 4,952	\$ 4,933	\$ 4,972
Wholesale revenues, non-affiliates	248	277	287
Wholesale revenues, affiliates	212	111	244
Other revenues	206	199	199
<b>Total operating revenues</b>	<b>5,618</b>	<b>5,520</b>	<b>5,702</b>
<b>Operating Expenses:</b>			
Fuel	1,631	1,503	1,679
Purchased power, non-affiliates	100	73	73
Purchased power, affiliates	129	182	198
Other operations and maintenance	1,289	1,287	1,262
Depreciation and amortization	645	639	637
Taxes other than income taxes	348	340	339
<b>Total operating expenses</b>	<b>4,142</b>	<b>4,024</b>	<b>4,188</b>
<b>Operating Income</b>	<b>1,476</b>	<b>1,496</b>	<b>1,514</b>
<b>Other Income and (Expense):</b>			
Allowance for equity funds used during construction	32	19	22
Interest income	16	16	18
Interest expense, net of amounts capitalized	(259)	(287)	(299)
Other income (expense), net	(36)	(24)	(30)
<b>Total other income and (expense)</b>	<b>(247)</b>	<b>(276)</b>	<b>(289)</b>
<b>Earnings Before Income Taxes</b>	<b>1,229</b>	<b>1,220</b>	<b>1,225</b>
Income taxes	478	477	478
<b>Net Income</b>	<b>751</b>	<b>743</b>	<b>747</b>
<b>Dividends on Preferred and Preference Stock</b>	<b>39</b>	<b>39</b>	<b>39</b>
<b>Net Income After Dividends on Preferred and Preference Stock</b>	<b>\$ 712</b>	<b>\$ 704</b>	<b>\$ 708</b>

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

**STATEMENTS OF COMPREHENSIVE INCOME**  
**For the Years Ended December 31, 2013, 2012, and 2011**  
**Alabama Power Company 2013 Annual Report**

	<b>2013</b>	2012	2011
		<i>(in millions)</i>	
<b>Net Income</b>	<b>\$ 751</b>	\$ 743	\$ 747
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of \$-, \$(7), and \$(5), respectively	—	(11)	(9)
Reclassification adjustment for amounts included in net income, net of tax of \$1, \$1, and \$(1), respectively	<b>1</b>	2	(2)
Total other comprehensive income (loss)	<b>1</b>	(9)	(11)
<b>Comprehensive Income</b>	<b>\$ 752</b>	\$ 734	\$ 736

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

**STATEMENTS OF CASH FLOWS**  
**For the Years Ended December 31, 2013, 2012, and 2011**  
**Alabama Power Company 2013 Annual Report**

	2013	2012	2011
	<i>(in millions)</i>		
<b>Operating Activities:</b>			
Net income	\$ 751	\$ 743	\$ 747
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	816	767	749
Deferred income taxes	198	164	459
Allowance for equity funds used during construction	(32)	(19)	(22)
Pension, postretirement, and other employee benefits	9	(21)	(41)
Stock based compensation expense	10	9	6
Natural disaster reserve	3	3	34
Other, net	(41)	(27)	(41)
Changes in certain current assets and liabilities —			
-Receivables	2	23	18
-Fossil fuel stock	146	(132)	47
-Materials and supplies	19	(21)	(33)
-Other current assets	5	(4)	(6)
-Accounts payable	35	(77)	11
-Accrued taxes	(23)	(12)	157
-Accrued compensation	(23)	(3)	(12)
-Retail fuel cost over recovery	42	1	—
-Other current liabilities	(3)	(18)	(25)
<b>Net cash provided from operating activities</b>	<b>1,914</b>	<b>1,376</b>	<b>2,048</b>
<b>Investing Activities:</b>			
Property additions	(1,107)	(867)	(977)
Investment in restricted cash from pollution control bonds	—	1	4
Distribution of restricted cash from pollution control bonds	—	—	13
Nuclear decommissioning trust fund purchases	(280)	(194)	(350)
Nuclear decommissioning trust fund sales	279	193	349
Cost of removal net of salvage	(47)	(33)	(28)
Change in construction payables	(13)	12	(9)
Other investing activities	26	(46)	9
<b>Net cash used for investing activities</b>	<b>(1,142)</b>	<b>(934)</b>	<b>(989)</b>
<b>Financing Activities:</b>			
Proceeds —			
Capital contributions from parent company	24	27	12
Senior notes issuances	300	1,000	700
Redemptions —			
Pollution control revenue bonds	—	(1)	(4)
Senior notes	(250)	(950)	(750)
Payment of preferred and preference stock dividends	(39)	(39)	(39)
Payment of common stock dividends	(644)	(684)	(774)
Other financing activities	(5)	(2)	(14)
<b>Net cash used for financing activities</b>	<b>(614)</b>	<b>(649)</b>	<b>(869)</b>
<b>Net Change in Cash and Cash Equivalents</b>	<b>158</b>	<b>(207)</b>	<b>190</b>
<b>Cash and Cash Equivalents at Beginning of Year</b>	<b>137</b>	<b>344</b>	<b>154</b>
<b>Cash and Cash Equivalents at End of Year</b>	<b>\$ 295</b>	<b>\$ 137</b>	<b>\$ 344</b>
<b>Supplemental Cash Flow Information:</b>			
Cash paid during the period for —			
Interest (net of \$11, \$7 and \$9 capitalized, respectively)	\$ 243	\$ 273	\$ 286
Income taxes (net of refunds)	296	309	(139)
Noncash transactions - accrued property additions at year-end	18	31	19

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

**BALANCE SHEETS**  
**At December 31, 2013 and 2012**  
**Alabama Power Company 2013 Annual Report**

Assets	2013	2012
	<i>(in millions)</i>	
<b>Current Assets:</b>		
Cash and cash equivalents	\$ 295	\$ 137
Receivables —		
Customer accounts receivable	341	321
Unbilled revenues	142	138
Under recovered regulatory clause revenues	—	23
Other accounts and notes receivable	30	42
Affiliated companies	54	55
Accumulated provision for uncollectible accounts	(8)	(8)
Fossil fuel stock, at average cost	329	475
Materials and supplies, at average cost	375	395
Vacation pay	63	61
Prepaid expenses	57	81
Other regulatory assets, current	7	24
Other current assets	6	13
Total current assets	1,691	1,757
<b>Property, Plant, and Equipment:</b>		
In service	22,092	21,407
Less accumulated provision for depreciation	8,114	7,761
Plant in service, net of depreciation	13,978	13,646
Nuclear fuel, at amortized cost	332	354
Construction work in progress	748	438
Total property, plant, and equipment	15,058	14,438
<b>Other Property and Investments:</b>		
Equity investments in unconsolidated subsidiaries	54	53
Nuclear decommissioning trusts, at fair value	714	605
Miscellaneous property and investments	80	78
Total other property and investments	848	736
<b>Deferred Charges and Other Assets:</b>		
Deferred charges related to income taxes	519	525
Prepaid pension costs	276	—
Deferred under recovered regulatory clause revenues	25	11
Other regulatory assets, deferred	692	1,083
Other deferred charges and assets	142	162
Total deferred charges and other assets	1,654	1,781
<b>Total Assets</b>	<b>\$ 19,251</b>	<b>\$ 18,712</b>

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

**BALANCE SHEETS**  
**At December 31, 2013 and 2012**  
**Alabama Power Company 2013 Annual Report**

<b>Liabilities and Stockholder's Equity</b>	<b>2013</b>	<b>2012</b>
	<i>(in millions)</i>	
<b>Current Liabilities:</b>		
Securities due within one year	\$ —	\$ 250
Accounts payable —		
Affiliated	198	191
Other	339	318
Customer deposits	85	85
Accrued taxes —		
Accrued income taxes	11	5
Other accrued taxes	33	33
Accrued interest	61	62
Accrued vacation pay	53	50
Accrued compensation	74	94
Other regulatory liabilities, current	37	3
Other current liabilities	41	52
Total current liabilities	932	1,143
<b>Long-Term Debt</b> (See accompanying statements)	6,233	5,929
<b>Deferred Credits and Other Liabilities:</b>		
Accumulated deferred income taxes	3,603	3,404
Deferred credits related to income taxes	75	79
Accumulated deferred investment tax credits	133	141
Employee benefit obligations	195	321
Asset retirement obligations	730	589
Other cost of removal obligations	828	759
Other regulatory liabilities, deferred	259	183
Deferred over recovered regulatory clause revenues	15	—
Other deferred credits and liabilities	61	81
Total deferred credits and other liabilities	5,899	5,557
<b>Total Liabilities</b>	<b>13,064</b>	<b>12,629</b>
<b>Redeemable Preferred Stock</b> (See accompanying statements)	342	342
<b>Preference Stock</b> (See accompanying statements)	343	343
<b>Common Stockholder's Equity</b> (See accompanying statements)	5,502	5,398
<b>Total Liabilities and Stockholder's Equity</b>	<b>\$ 19,251</b>	<b>\$ 18,712</b>
<b>Commitments and Contingent Matters</b> (See notes)		

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

**STATEMENTS OF CAPITALIZATION**  
**At December 31, 2013 and 2012**  
**Alabama Power Company 2013 Annual Report**

	<b>2013</b>	2012	<b>2013</b>	2012
	<i>(in millions)</i>		<i>(percent of total)</i>	
<b>Long-Term Debt:</b>				
Long-term debt payable to affiliated trusts —				
Variable rate (3.35% at 1/1/14) due 2042	<b>\$ 206</b>	\$ 206		
Long-term notes payable —				
5.80% due 2013	—	250		
0.55% due 2015	<b>400</b>	400		
5.20% due 2016	<b>200</b>	200		
5.50% to 5.55% due 2017	<b>525</b>	525		
3.375% to 6.125% due 2019-2042	<b>3,750</b>	3,450		
Total long-term notes payable	<b>4,875</b>	4,825		
Other long-term debt —				
Pollution control revenue bonds —				
0.40% to 5.00% due 2034	<b>367</b>	367		
Variable rate (0.04% at 1/1/14) due 2015	<b>54</b>	54		
Variable rates (0.09% to 0.10% at 1/1/14) due 2017	<b>36</b>	36		
Variable rates (0.02% to 0.13% at 1/1/14) due 2021-2038	<b>694</b>	694		
Total other long-term debt	<b>1,151</b>	1,151		
Capitalized lease obligations	<b>5</b>	—		
Unamortized debt premium (discount), net	<b>(4)</b>	(3)		
Total long-term debt (annual interest requirement — \$243 million)	<b>6,233</b>	6,179		
Less amount due within one year	—	250		
Long-term debt excluding amount due within one year	<b>6,233</b>	5,929	<b>50.2%</b>	49.4%

**STATEMENTS OF CAPITALIZATION (continued)**  
**At December 31, 2013 and 2012**  
**Alabama Power Company 2013 Annual Report**

	2013	2012	2013	2012
	<i>(in millions)</i>		<i>(percent of total)</i>	
<b>Redeemable Preferred Stock:</b>				
<u>Cumulative redeemable preferred stock</u>				
\$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		
<b>Total redeemable preferred stock</b>	<b>342</b>	<b>342</b>	<b>2.7</b>	<b>2.8</b>
<b>Preference Stock:</b>				
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	2.8	2.9
<b>Common Stockholder's Equity:</b>				
Common stock, par value \$40 per share —				
Authorized: 40,000,000 shares				
Outstanding: 30,537,500 shares	1,222	1,222		
Paid-in capital	2,262	2,227		
Retained earnings	2,044	1,976		
Accumulated other comprehensive income (loss)	(26)	(27)		
<b>Total common stockholder's equity</b>	<b>5,502</b>	<b>5,398</b>	<b>44.3</b>	<b>44.9</b>
<b>Total Capitalization</b>	<b>\$ 12,420</b>	<b>\$ 12,012</b>	<b>100.0%</b>	<b>100.0%</b>

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

**STATEMENTS OF COMMON STOCKHOLDER'S EQUITY**  
**For the Years Ended December 31, 2013, 2012, and 2011**  
**Alabama Power Company 2013 Annual Report**

	<b>Number of Common Shares Issued</b>	<b>Common Stock</b>	<b>Paid-In Capital</b>	<b>Retained Earnings</b>	<b>Accumulated Other Comprehensive Income (Loss)</b>	<b>Total</b>
				<i>(in millions)</i>		
<b>Balance at December 31, 2010</b>	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)
<b>Balance at December 31, 2011</b>	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)
<b>Balance at December 31, 2012</b>	<b>31</b>	<b>1,222</b>	<b>2,227</b>	<b>1,976</b>	<b>(27)</b>	<b>5,398</b>
Net income after dividends on preferred and preference stock	—	—	—	712	—	712
Capital contributions from parent company	—	—	35	—	—	35
Other comprehensive income (loss)	—	—	—	—	1	1
Cash dividends on common stock	—	—	—	(644)	—	(644)
<b>Balance at December 31, 2013</b>	<b>31</b>	<b>\$ 1,222</b>	<b>\$ 2,262</b>	<b>\$ 2,044</b>	<b>\$ (26)</b>	<b>\$ 5,502</b>

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

**Index to the Notes to Financial Statements**

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## NOTES (continued)

### Alabama Power Company 2013 Annual Report

#### 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, construction management, and power pool transactions. Costs for these services amounted to \$340 million, \$340 million, and \$347 million during 2013, 2012, and 2011, 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 U.S. 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 \$211 million, \$218 million, and \$215 million during 2013, 2012, and 2011, 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 \$13 million in 2013, \$12 million in 2012, and \$12 million in 2011. Also, Mississippi Power reimburses the Company for any direct fuel purchases delivered from one of the Company's transfer facilities, which were \$27 million in 2013, \$28 million in 2012, and \$21 million in 2011. See Note 4 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 \$22 million in 2013 and \$31 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.

**NOTES (continued)**

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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 2013, 2012, or 2011.

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.

**NOTES (continued)**  
**Alabama Power Company 2013 Annual Report**

**Regulatory Assets and Liabilities**

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

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

	2013	2012	Note
	<i>(in millions)</i>		
Deferred income tax charges	\$ 519	\$ 525	(a,k)
Loss on reacquired debt	86	93	(b)
Vacation pay	63	61	(c,j)
Under/(over) recovered regulatory clause revenues	(18)	34	(d)
Fuel-hedging (realized and unrealized) losses	8	18	(e)
Other regulatory assets	52	51	(f)
Asset retirement obligations	(132)	(64)	(a)
Other cost of removal obligations	(828)	(759)	(a)
Deferred income tax credits	(75)	(79)	(a)
Fuel-hedging (realized and unrealized) gains	(8)	(5)	(e)
Nuclear outage	51	33	(d)
Natural disaster reserve	(96)	(103)	(h)
Other regulatory liabilities	(11)	(13)	(d,g)
Retiree benefit plans	461	911	(i,j)
Regulatory deferrals	20	—	(l)
<b>Total regulatory assets (liabilities), net</b>	<b>\$ 92</b>	<b>\$ 703</b>	

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 ten 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) Comprised of components including generation site selection/evaluation costs, PPA capacity, and other miscellaneous assets. Recorded as accepted by the Alabama PSC. Capitalized upon initialization of related construction projects, if applicable.
- (g) Comprised of components including mine reclamation and remediation liabilities and other liabilities. 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 are \$20 million for 2013 and \$21 million for 2012 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) Recorded and amortized as approved by the Alabama PSC for 2015 through 2017.

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 to be reflected in rates. See Note 3 under "Retail Regulatory Matters" for additional information.

**NOTES (continued)**  
**Alabama Power Company 2013 Annual Report**

**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 (ITCs) 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:

	2013	2012
	<i>(in millions)</i>	
Generation	\$ 11,314	\$ 11,110
Transmission	3,287	3,137
Distribution	5,934	5,714
General	1,545	1,434
Plant acquisition adjustment	12	12
Total plant in service	\$ 22,092	\$ 21,407

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 expenses 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 amortization 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. These expenses were fully amortized in June 2013. The

**NOTES (continued)****Alabama Power Company 2013 Annual Report**

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. These expenses were fully amortized in December 2013.

During 2013, the Company deferred \$28 million of nuclear outage expenses associated with the spring 2013 outage and began the 18-month amortization cycle for expenses in July 2013. The Company deferred an additional \$32 million of nuclear outage expenses associated with the fall 2013 outage and began the 18-month amortization cycle for expenses in January 2014.

The total unamortized deferred nuclear outage expense balance of \$51 million is included in the 2013 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 2013 and 2012, and 3.3% in 2011. 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 composite 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 settlement timing for the retirement obligations related to these assets are indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these asset retirement obligations will be recognized when sufficient information becomes available to support a reasonable estimation of the asset retirement obligation. 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:

	2013	2012
	<i>(in millions)</i>	
Balance at beginning of year	\$ 589	\$ 553
Liabilities incurred	—	—
Liabilities settled	(1)	(1)
Accretion	40	37
Cash flow revisions <sup>(a)</sup>	102	—
<b>Balance at end of year</b>	<b>\$ 730</b>	<b>\$ 589</b>

(a) Updated based on results from the 2013 nuclear decommissioning study

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**Nuclear Decommissioning**

The U.S. 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, 2013, investment securities in the Funds totaled \$713 million, consisting of equity securities of \$566 million, debt securities of \$131 million, and \$16 million of other securities. 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. 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 \$279 million, \$193 million, and \$349 million in 2013, 2012, and 2011, respectively, all of which were reinvested. For 2013, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were \$120 million, of which \$5 million related to realized gains and \$85 million related to unrealized gains related to securities held in the Funds at December 31, 2013. 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. 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, the accumulated provisions for decommissioning were as follows:

	<b>2013</b>	<b>2012</b>
	<i>(in millions)</i>	
External trust funds	<b>\$ 713</b>	<b>\$ 604</b>
Internal reserves	<b>21</b>	<b>22</b>
<b>Total</b>	<b>\$ 734</b>	<b>\$ 626</b>

**NOTES (continued)**  
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Site study costs is the estimate to decommission a facility as of the site study year. The estimated costs of decommissioning as of December 31, 2013 based on the most current study performed in 2013 for Plant Farley are as follows:

Decommissioning periods:	
Beginning year	2037
Completion year	2076
<i>(in millions)</i>	
Site study costs:	
Radiated structures	\$ 1,362
Non-radiated structures	80
Total site study costs	\$ 1,442

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 2018.

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 and is recovered 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 9.1% in 2013, 9.4% in 2012, and 9.2% in 2011. AFUDC, net of income taxes, as a percent of net income after dividends on preferred and preference stock was 5.4% in 2013, 3.3% in 2012, and 3.9% in 2011.

**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-

## **NOTES (continued)**

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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 "Retail Regulatory Matters – 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 U.S. 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. If any, immaterial 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 and had immaterial reclaim collateral arising from derivative instruments recognized at December 31, 2013.

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.

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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, trustee, 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 were made to the qualified pension plan during 2013. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2014. 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. No contributions to the other postretirement trusts are expected during the year ending December 31, 2014.

**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 2010 for the 2011 plan year using discount rates for the pension plans and the other postretirement benefit plans of 5.52% and 5.41%, respectively, and an annual salary increase of 3.84%.

	2013	2012	2011
Discount rate:			
Pension plans	<b>5.02%</b>	4.27%	4.98%
Other postretirement benefit plans	<b>4.86</b>	4.06	4.88
Annual salary increase	<b>3.59</b>	3.59	3.84
Long-term return on plan assets:			
Pension plans	<b>8.20</b>	8.20	8.45
Other postretirement benefit plans	<b>7.36</b>	7.19	7.39

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

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate of 7.00% for 2014, decreasing gradually to 5.00% through the year 2021 and remaining at that level thereafter. An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2013 as follows:

	<b>1 Percent Increase</b>	<b>1 Percent Decrease</b>
	<i>(in millions)</i>	
Benefit obligation	\$ 26	\$ (22)
Service and interest costs	1	(1)

**NOTES (continued)**  
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**Pension Plans**

The total accumulated benefit obligation for the pension plans was \$1.9 billion at December 31, 2013 and \$2.0 billion at December 31, 2012. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2013 and 2012 were as follows:

	2013	2012
	<i>(in millions)</i>	
<b>Change in benefit obligation</b>		
Benefit obligation at beginning of year	\$ 2,218	\$ 1,932
Service cost	52	44
Interest cost	93	94
Benefits paid	(93)	(90)
Actuarial (gain) loss	(158)	238
Balance at end of year	2,112	2,218
<b>Change in plan assets</b>		
Fair value of plan assets at beginning of year	2,077	1,885
Actual return on plan assets	285	274
Employer contributions	9	8
Benefits paid	(93)	(90)
Fair value of plan assets at end of year	2,278	2,077
Prepaid pension costs (accrued liability)	\$ 166	\$ (141)

At December 31, 2013, the projected benefit obligations for the qualified and non-qualified pension plans were \$2.0 billion and \$110 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2013 and 2012 related to the Company's pension plans consist of the following:

	2013	2012
	<i>(in millions)</i>	
Prepaid pension costs	\$ 276	\$ —
Other regulatory assets, deferred	476	822
Other current liabilities	(9)	(8)
Employee benefit obligations	(101)	(133)

Presented below are the amounts included in regulatory assets at December 31, 2013 and 2012 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 2014.

	2013	2012	Estimated Amortization in 2014
	<i>(in millions)</i>		
Prior service cost	\$ 19	\$ 26	\$ 7
Net (gain) loss	457	796	31
Regulatory assets	\$ 476	\$ 822	

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The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2013 and 2012 are presented in the following table:

	2013	2012
	<i>(in millions)</i>	
<b>Regulatory assets:</b>		
Beginning balance	\$ 822	\$ 727
Net (gain) loss	(287)	125
Reclassification adjustments:		
Amortization of prior service costs	(7)	(7)
Amortization of net gain (loss)	(52)	(23)
Total reclassification adjustments	(59)	(30)
Total change	(346)	95
Ending balance	\$ 476	\$ 822

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

	2013	2012	2011
	<i>(in millions)</i>		
Service cost	\$ 52	\$ 44	\$ 43
Interest cost	93	94	96
Expected return on plan assets	(157)	(162)	(173)
Recognized net (gain) loss	52	23	4
Net amortization	7	7	9
Net periodic pension cost (income)	\$ 47	\$ 6	\$ (21)

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, 2013, estimated benefit payments were as follows:

	<b>Benefit Payments</b>	
	<i>(in millions)</i>	
2014	\$	104
2015		108
2016		113
2017		118
2018		122
2019 to 2023		669

**NOTES (continued)**  
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**Other Postretirement Benefits**

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2013 and 2012 were as follows:

	<b>2013</b>		2012
	<i>(in millions)</i>		
<b>Change in benefit obligation</b>			
Benefit obligation at beginning of year	\$ 490	\$	470
Service cost	6		5
Interest cost	19		22
Benefits paid	(24)		(24)
Actuarial (gain) loss	(62)		15
Retiree drug subsidy	2		2
Balance at end of year	<b>431</b>		490
<b>Change in plan assets</b>			
Fair value of plan assets at beginning of year	343		315
Actual return on plan assets	61		39
Employer contributions	7		11
Benefits paid	(22)		(22)
Fair value of plan assets at end of year	<b>389</b>		343
Accrued liability	\$ (42)	\$	(147)

Amounts recognized in the balance sheets at December 31, 2013 and 2012 related to the Company's other postretirement benefit plans consist of the following:

	<b>2013</b>		2012
	<i>(in millions)</i>		
Other regulatory assets, deferred	\$ 6	\$	89
Other regulatory liabilities, deferred	(21)		—
Employee benefit obligations	<b>(42)</b>		(147)

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Presented below are the amounts included in net regulatory assets (liabilities) at December 31, 2013 and 2012 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 2014.

	2013	2012	Estimated Amortization in 2014
	<i>(in millions)</i>		
Prior service cost	\$ 19	\$ 22	\$ 4
Net (gain) loss	(34)	67	—
<b>Net regulatory assets (liabilities)</b>	<b>\$ (15)</b>	<b>\$ 89</b>	

The changes in the balance of net regulatory assets (liabilities) related to the other postretirement benefit plans for the plan years ended December 31, 2013 and 2012 are presented in the following table:

	2013	2012
	<i>(in millions)</i>	
<b>Net regulatory assets (liabilities):</b>		
Beginning balance	\$ 89	\$ 96
Net gain	(99)	(1)
Reclassification adjustments:		
Amortization of transition obligation	—	(2)
Amortization of prior service costs	(3)	(4)
Amortization of net gain (loss)	(2)	—
<b>Total reclassification adjustments</b>	<b>(5)</b>	<b>(6)</b>
<b>Total change</b>	<b>(104)</b>	<b>(7)</b>
<b>Ending balance</b>	<b>\$ (15)</b>	<b>\$ 89</b>

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

	2013	2012	2011
	<i>(in millions)</i>		
Service cost	\$ 6	\$ 5	\$ 5
Interest cost	19	22	24
Expected return on plan assets	(23)	(23)	(25)
Net amortization	5	6	7
<b>Net periodic postretirement benefit cost</b>	<b>\$ 7</b>	<b>\$ 10</b>	<b>\$ 11</b>

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
	<i>(in millions)</i>		
2014	\$ 30	\$ (3)	\$ 27
2015	31	(3)	28
2016	31	(3)	28
2017	33	(4)	29
2018	33	(4)	29
2019 to 2023	164	(22)	142

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**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, 2013 and 2012, along with the targeted mix of assets for each plan, is presented below:

	Target	2013	2012
<b>Pension plan assets:</b>			
Domestic equity	26%	<b>31%</b>	28%
International equity	25	<b>25</b>	24
Fixed income	23	<b>23</b>	27
Special situations	3	<b>1</b>	1
Real estate investments	14	<b>14</b>	13
Private equity	9	<b>6</b>	7
Total	100%	<b>100%</b>	100%
<b>Other postretirement benefit plan assets:</b>			
Domestic equity	44%	<b>47%</b>	46%
International equity	20	<b>20</b>	20
Domestic fixed income	24	<b>27</b>	28
Special situations	1	—	—
Real estate investments	8	<b>4</b>	4
Private equity	3	<b>2</b>	2
Total	100%	<b>100%</b>	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 and interest rates, 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.

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- **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, 2013 and 2012. 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:

- **Domestic and international equity.** 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.
- **Fixed income.** 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.
- **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.
- **Real estate investments and private equity.** 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.

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The fair values of pension plan assets as of December 31, 2013 and 2012 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, 2013:	Fair Value Measurements Using			Total
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	
	<i>(in millions)</i>			
Assets:				
Domestic equity*	\$ 374	\$ 219	\$ —	\$ 593
International equity*	287	265	—	552
Fixed income:				
U.S. Treasury, government, and agency bonds	—	156	—	156
Mortgage- and asset-backed securities	—	41	—	41
Corporate bonds	—	255	—	255
Pooled funds	—	123	—	123
Cash equivalents and other	—	58	—	58
Real estate investments	68	—	261	329
Private equity	—	—	149	149
<b>Total</b>	<b>\$ 729</b>	<b>\$ 1,117</b>	<b>\$ 410</b>	<b>\$ 2,256</b>
Liabilities:				
Derivatives	—	(1)	—	(1)
<b>Total</b>	<b>\$ 729</b>	<b>\$ 1,116</b>	<b>\$ 410</b>	<b>\$ 2,255</b>

\* 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.

NOTES (continued)  
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As of December 31, 2012:	Fair Value Measurements Using			Total
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	
	<i>(in millions)</i>			
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
<b>Total</b>	<b>\$ 610</b>	<b>\$ 1,076</b>	<b>\$ 376</b>	<b>\$ 2,062</b>

\* 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, 2013 and 2012 were as follows:

	2013		2012	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
	<i>(in millions)</i>			
Beginning balance	\$ 220	\$ 155	\$ 217	\$ 161
Actual return on investments:				
Related to investments held at year end	19	2	2	—
Related to investments sold during the year	8	13	1	2
Total return on investments	27	15	3	2
Purchases, sales, and settlements	14	(21)	—	(8)
<b>Ending balance</b>	<b>\$ 261</b>	<b>\$ 149</b>	<b>\$ 220</b>	<b>\$ 155</b>

The fair values of other postretirement benefit plan assets as of December 31, 2013 and 2012 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.

NOTES (continued)  
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As of December 31, 2013:	Fair Value Measurements Using			Total
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	
<i>(in millions)</i>				
Assets:				
Domestic equity*	\$ 67	\$ 11	\$ —	\$ 78
International equity*	14	13	—	27
Fixed income:				
U.S. Treasury, government, and agency bonds	—	17	—	17
Mortgage- and asset-backed securities	—	2	—	2
Corporate bonds	—	12	—	12
Pooled funds	—	6	—	6
Cash equivalents and other	—	10	—	10
Trust-owned life insurance	—	211	—	211
Real estate investments	4	—	13	17
Private equity	—	—	7	7
<b>Total</b>	<b>\$ 85</b>	<b>\$ 282</b>	<b>\$ 20</b>	<b>\$ 387</b>

\* 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, 2012:	Fair Value Measurements Using			Total
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	
<i>(in millions)</i>				
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
<b>Total</b>	<b>\$ 78</b>	<b>\$ 244</b>	<b>\$ 19</b>	<b>\$ 341</b>

\* 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.

**NOTES (continued)**  
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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, 2013 and 2012 were as follows:

	2013		2012	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
	<i>(in millions)</i>			
Beginning balance	\$ 11	\$ 8	\$ 11	\$ 8
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	(1)	—	—
Ending balance	\$ 13	\$ 7	\$ 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 2013, 2012, and 2011 were \$20 million, \$19 million, and \$18 million, respectively.

**3. CONTINGENCIES AND REGULATORY MATTERS**

**General Litigation Matters**

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as 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 residuals, 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***

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the EPA brought civil enforcement actions in federal district court against the Company alleging violations of the New Source Review (NSR) provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by Mississippi Power. These civil actions seek penalties and injunctive relief, including orders requiring installation of the best available control technologies at the affected units. The case against the Company (including claims involving a unit co-owned by Mississippi Power) has been actively litigated in the U.S. District Court for the Northern District of Alabama, resulting in a settlement in 2006 of the alleged NSR violations at Plant Miller; voluntary dismissal of certain claims by the EPA; and a grant of summary judgment for the Company on all remaining claims and dismissal of the case with prejudice in 2011. On September 19, 2013, the U.S. Court of Appeals for the Eleventh Circuit affirmed in part and reversed in part the 2011 judgment in favor of the Company, and the case has been transferred back to the U.S. District Court for the Northern District of Alabama for further proceedings.

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.

**NOTES (continued)**  
**Alabama Power Company 2013 Annual Report**

***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 the vast majority 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 accumulate until the issue is resolved or storage is provided. No amounts have been recognized in the financial statements as of December 31, 2013 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 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 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%. If the Company's actual retail return is above the allowed equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail return fall below the allowed equity return range. Prior to 2014, retail rates remained unchanged when the retail return on common equity (ROE) was projected to be between 13.0% and 14.5%.

During 2013, the Alabama PSC held public proceedings regarding the operation and utilization of Rate RSE. On August 13, 2013, the Alabama PSC voted to issue a report on Rate RSE that found that the Company's Rate RSE mechanism continues to be just and reasonable to customers and the Company, but recommended the Company modify Rate RSE as follows:

- Eliminate the provision of Rate RSE establishing an allowed range of ROE.
- Eliminate the provision of Rate RSE limiting the Company's capital structure to an allowed equity ratio of 45%.
- Replace these two provisions with a provision that establishes rates based upon an allowed weighted cost of equity (WCE) range of 5.75% to 6.21%, with an adjusting point of 5.98%. If calculated under the previous Rate RSE provisions, the resulting WCE would range from 5.85% to 6.53%, with an adjusting point of 6.19%.

## **NOTES (continued)**

### **Alabama Power Company 2013 Annual Report**

- Provide eligibility for a performance-based adder of seven basis points, or 0.07%, to the WCE adjusting point if the Company (i) has an "A" credit rating equivalent with at least one of the recognized rating agencies or (ii) is in the top one-third of a designated customer value benchmark survey.

Substantially all other provisions of Rate RSE were unchanged.

On August 21, 2013, the Company filed its consent to these recommendations with the Alabama PSC. The changes became effective for calendar year 2014. On November 27, 2013, the Company made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2014; projected earnings were within the specified WCE range and, therefore, retail rates under Rate RSE remained unchanged for 2014. In 2012 and 2013, retail rates under Rate RSE remained unchanged from 2011. Under the terms of Rate RSE, the maximum possible increase for 2015 is 5.00%.

#### ***Rate CNP***

The Company's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service 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). There was no adjustment to Rate CNP PPA in 2012. On March 5, 2013, 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, 2013 through March 31, 2014. It is anticipated that no adjustment will be made to Rate CNP PPA in 2014. As of December 31, 2013, the Company had an under recovered certificated PPA balance of \$18 million, all of which is included in deferred under recovered regulatory clause revenues in the balance sheet.

In 2011, the Alabama PSC approved and certificated a PPA of approximately 200 megawatts (MWs) of energy from wind-powered generating facilities which became operational in December 2012. In September 2012, the Alabama PSC approved and certificated a second wind PPA of approximately 200 MWs which became operational in January 2014. The terms of the wind PPAs 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. The Company has elected the normal purchase normal sale (NPNS) scope exception under the derivative accounting rules for its two wind PPAs, which total approximately 400 MWs. The NPNS exception allows the PPAs to be recorded at a cost, rather than fair value, basis. The industry's application of the NPNS exception to certain physical forward transactions in nodal markets is currently under review by the SEC at the request of the electric utility industry. The outcome of the SEC's review cannot now be determined. If the Company is ultimately required to record these PPAs at fair value, an offsetting regulatory asset or regulatory liability will be recorded.

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 in 2012 or 2013. On August 13, 2013, the Alabama PSC approved the Company's petition requesting a revision to Rate CNP Environmental that allows recovery of costs related to pre-2005 environmental assets previously being recovered through Rate RSE. The revenue impact as a result of this revision is estimated to be \$58 million in 2014. On November 21, 2013, 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 approximately \$72 million, which is to be recovered in the billing months of January 2014 through December 2014. On December 3, 2013, the Alabama PSC issued a consent order that the Company leave in effect for 2014 the factors associated with the Company's environmental compliance costs for the year 2013. Any unrecovered amounts associated with 2014 will be reflected in the 2015 filing. As of December 31, 2013, the Company had an under recovered environmental clause balance of \$7 million which is included in deferred under recovered regulatory clause revenues in the balance sheet.

#### ***Environmental Accounting Order***

Based on an order from the Alabama PSC, the Company is allowed to establish a regulatory asset to record the unrecovered investment costs, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure associated with future unit retirements caused by environmental regulations. 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***

In November 2012, the Alabama PSC approved an accounting order to defer to a regulatory asset account certain compliance-related operations and maintenance expenditures for the years 2013 through 2017, as well as the incremental increase in

## NOTES (continued)

### Alabama Power Company 2013 Annual Report

operations expense related to pension cost for 2013. These deferred costs are to be amortized over a three-year period beginning in January 2015. The compliance related expenditures were related to (i) standards addressing Critical Infrastructure Protection issued by the North American Electric Reliability Corporation, (ii) cyber security requirements issued by the NRC, and (iii) NRC guidance addressing the readiness at nuclear facilities within the U.S. for severe events. The compliance-related expenses to be afforded regulatory asset treatment over the five-year period are currently estimated to be approximately \$37 million. The amount of operations and maintenance expenses deferred to a regulatory asset in 2013 associated with compliance-related expenditures and pension cost was approximately \$8 million and \$12 million, respectively. Pursuant to the accounting order, the Company has the ability to accelerate the amortization of the regulatory assets with notification to the Alabama PSC.

#### *Retail 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 3, 2013, the Alabama PSC issued a consent order that the Company leave in effect the energy cost recovery rates which began in April 2011 for 2014. Therefore, the Rate ECR factor as of January 1, 2014 remained at 2.681 cents per KWH. Effective with billings beginning in January 2015, the Rate ECR factor will be 5.910 cents per KWH, absent a further order from the Alabama PSC.

The Company's over recovered fuel costs at December 31, 2013 totaled \$42 million as compared to under recovered fuel costs of \$4 million at December 31, 2012. At December 31, 2013, \$27 million is included in other regulatory liabilities, current and \$15 million is included in deferred over recovered regulatory clause revenues. The under recovered fuel costs at December 31, 2012 are included in deferred under recovered regulatory clause revenues in the balance sheets. These classifications are based on estimates, which include such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any 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.

In accordance with the order that was issued by the Alabama PSC in 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, 2013 and December 31, 2012 were approximately \$96 million and \$103 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.

**NOTES (continued)**  
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***Nuclear Outage Accounting Order***

In accordance with a 2010 Alabama PSC order, nuclear outage operations and maintenance expenses for the two units at Plant Farley are deferred to a regulatory asset when the charges actually occur and are then amortized over the subsequent 18-month operational cycle.

Approximately \$31 million of nuclear outage costs from the spring of 2012 was amortized to nuclear operations and maintenance expenses over the 18-month period ended in December 2013. During the spring of 2013, approximately \$28 million of nuclear outage costs was deferred to a regulatory asset, and beginning in July 2013, these deferred costs are being amortized over an 18-month period. During the fall of 2013, approximately \$32 million of nuclear outage costs associated with the second unit was deferred to a regulatory asset, and beginning in January 2014, these deferred costs are being amortized 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 Alabama PSC order.

***Non-Nuclear Outage Accounting Order***

On August 13, 2013, the Alabama PSC approved the Company's petition requesting authorization to defer to a regulatory asset account certain operations and maintenance expenses associated with planned outages at non-nuclear generation facilities in 2014 and to amortize those expenses over a three-year period beginning in 2015. The 2014 outage expenditures to be deferred and amortized are estimated to total approximately \$78 million.

**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 ROE. The Company's share of purchased power totaled \$88 million in 2013, \$109 million in 2012, and \$142 million in 2011 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. The Company has guaranteed \$100 million principal amount of unsecured senior notes issued by SEGCO for general corporate purposes. These senior notes mature on December 1, 2018. The Company had guaranteed \$50 million principal amount of unsecured senior notes issued by SEGCO for general corporate purposes, which matured 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 guarantee.

At December 31, 2013, the capitalization of SEGCO consisted of \$84 million of equity and \$125 million of long-term debt on which the annual interest requirement is \$3 million. SEGCO paid dividends of \$7 million in 2013, \$14 million in 2012, and \$15 million in 2011, 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, developing, and constructing 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, 2013, the Company's portion of the construction work in progress associated with the pipeline is \$1 million.

**NOTES (continued)**  
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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, 2013 were as follows:

Facility	Total Megawatt Capacity	Company Ownership	Plant in Service	Accumulated Depreciation	Construction Work in Progress
				<i>(in millions)</i>	
Greene County Plant Miller Units 1 and 2	500	60.00% <sup>(1)</sup>	\$ 157	\$ 91	\$ 5
	1,320	91.84% <sup>(2)</sup>	1,410	575	89

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

(2) Jointly owned with PowerSouth Energy Cooperative, Inc.

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 Southern Company 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:

	2013	2012	2011
		<i>(in millions)</i>	
Federal —			
Current	\$ 243	\$ 262	\$ 20
Deferred	160	137	377
	403	399	397
State —			
Current	36	51	(1)
Deferred	39	27	82
	75	78	81
Total	\$ 478	\$ 477	\$ 478

**NOTES (continued)**  
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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:

	2013	2012
	<i>(in millions)</i>	
Deferred tax liabilities —		
Accelerated depreciation	\$ 3,187	\$ 2,989
Property basis differences	458	420
Premium on reacquired debt	33	36
Employee benefit obligations	209	218
Under recovered energy clause	—	16
Regulatory assets associated with employee benefit obligations	198	378
Asset retirement obligations	38	—
Regulatory assets associated with asset retirement obligations	265	248
Other	128	114
<b>Total</b>	<b>4,516</b>	<b>4,419</b>
Deferred tax assets —		
Federal effect of state deferred taxes	205	194
Unbilled fuel revenue	41	39
Storm reserve	32	34
Employee benefit obligations	231	408
Other comprehensive losses	18	19
Asset retirement obligations	303	248
Other	108	98
<b>Total</b>	<b>938</b>	<b>1,040</b>
Total deferred tax liabilities, net	3,578	3,379
Portion included in prepaid expenses (accrued income taxes)	25	25
<b>Accumulated deferred income taxes</b>	<b>\$ 3,603</b>	<b>\$ 3,404</b>

At December 31, 2013, the Company's tax-related regulatory assets to be recovered from customers were \$519 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, 2013, the Company's tax-related regulatory liabilities to be credited to customers were \$75 million. These liabilities are primarily attributable to unamortized ITCs.

In accordance with regulatory requirements, deferred ITCs 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 2013, 2012, and 2011. At December 31, 2013, all ITCs 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 placed in service in 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 placed in service in 2013 (and for certain long-term production-period projects to be placed in service in 2014).

The application of the bonus depreciation provisions in these laws significantly increased deferred tax liabilities related to accelerated depreciation in 2013, 2012, and 2011.

**NOTES (continued)**  
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**Effective Tax Rate**

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

	2013	2012	2011
Federal statutory rate	35.0%	35.0%	35.0%
State income tax, net of federal deduction	4.0	4.1	4.3
Non-deductible book depreciation	1.0	0.9	0.8
Differences in prior years' deferred and current tax rates	(0.1)	(0.1)	(0.1)
AFUDC equity	(0.9)	(0.5)	(0.6)
Other	(0.1)	(0.3)	(0.4)
Effective income tax rate	38.9%	39.1%	39.0%

The changes in the Company's 2013 and 2012 effective tax rates were not material.

**Unrecognized Tax Benefits**

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

	2013	2012	2011
		<i>(in millions)</i>	
Unrecognized tax benefits at beginning of year	\$ 31	\$ 32	\$ 43
Tax positions from current periods	—	5	6
Tax positions from prior periods	(31)	(4)	(17)
Reductions due to settlements	—	(2)	—
Balance at end of year	\$ —	\$ 31	\$ 32

The tax positions decrease from prior periods for 2013 relates primarily to the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information.

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

	2013	2012	2011
		<i>(in millions)</i>	
Tax positions impacting the effective tax rate	\$ —	\$ —	\$ 5
Tax positions not impacting the effective tax rate	—	31	27
Balance of unrecognized tax benefits	\$ —	\$ 31	\$ 32

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 is as follows:

	2013	2012	2011
		<i>(in millions)</i>	
Interest accrued at beginning of year	\$ —	\$ 1.9	\$ 1.5
Interest reclassified due to settlements	—	(1.9)	—
Interest accrued during the year	—	—	0.4
Balance at end of year	\$ —	\$ —	\$ 1.9

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

## **NOTES (continued)**

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It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months. The settlement of federal and 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 finalized its audits of Southern Company's consolidated federal income tax returns through 2011. Southern Company has filed its 2012 federal income tax return and has received a full acceptance letter from the IRS; however, the IRS has not finalized its audit. For tax years 2012 and 2013, Southern Company was 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**

In 2011, 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. Additionally, on April 30, 2013, the IRS issued Revenue Procedure 2013-24, which provides guidance for taxpayers related to the deductibility of repair costs associated with generation assets. Based on a review of the regulations, Southern Company incorporated provisions related to repair costs for generation assets into its consolidated 2012 federal income tax return and reversed all related unrecognized tax positions. On September 19, 2013, the IRS issued Treasury Decision 9636, "Guidance Regarding Deduction and Capitalization of Expenditures Related to Tangible Property," which are final tangible property regulations applicable to taxable years beginning on or after January 1, 2014. Southern Company is currently reviewing this new guidance. The ultimate outcome of this matter cannot be determined at this time; however, these regulations are not expected to have a material impact on the Company's financial statements.

## **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, 2013 and 2012, 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 each of December 31, 2013 and 2012, 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, 2013, the Company had no scheduled maturities of senior notes due within one year. At December 31, 2012, the Company had \$250 million of senior notes due within one year.

Maturities of senior notes and pollution control revenue bonds through 2018 applicable to total long-term debt are as follows: \$454 million in 2015; \$200 million in 2016; and \$561 million in 2017. There are no scheduled maturities in 2014 and 2018.

#### **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 2013. The amount of tax-exempt pollution control revenue bonds outstanding at each of December 31, 2013 and 2012 was \$1.2 billion, respectively.

#### **Senior Notes**

In December 2013, the Company issued \$300 million aggregate principal amount of its Series 2013A 3.55% Senior Notes due December 1, 2023. The proceeds of these issuances were used for general corporate purposes, including the Company's continuous construction program.

In November 2013, the Company's \$250 million aggregate principal amount of its Series 2008B 5.80% Senior Notes due November 15, 2013 matured.

**NOTES (continued)**  
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At December 31, 2013 and 2012, the Company had \$4.9 billion and \$4.8 billion of senior notes outstanding, respectively. These senior notes are effectively subordinated to all secured debt of the Company which amounted to approximately \$153 million at December 31, 2013.

**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:

<b>Preferred/Preference Stock</b>	<b>Par Value/ Stated Capital Per Share</b>	<b>Shares Outstanding</b>	<b>First Call Date</b>	<b>Redemption Price Per Share</b>
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, 2013. 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.

**NOTES (continued)**  
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**Bank Credit Arrangements**

At December 31, 2013, committed credit arrangements with banks were as follows:

Expires <sup>(a)</sup>					Executable Term-Loans		Due Within One Year	
2014	2015	2018	Total	Unused	One Year	Two Years	Term Out	No Term Out
<i>(in millions)</i>								
\$ 238	\$ 35	\$ 1,030	\$ 1,303	\$ 1,303	\$ 53	\$ —	\$ 53	\$ 185

(a) No credit arrangements expire in 2016 or 2017.

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 <sup>1</sup>/<sub>4</sub> 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, 2013, the Company was in compliance with the debt limit covenants.

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. The amount of variable rate pollution control revenue bonds requiring liquidity support was \$793 million as of December 31, 2013. In addition, at December 31, 2013, the Company had \$200 million of fixed rate pollution control revenue bonds that will be required to be remarketed within the next 12 months.

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, 2013 and 2012, there was no short-term debt outstanding. At December 31, 2013, the Company had regulatory approval to have outstanding up to \$2 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 and delivery of fossil and nuclear fuel which are not recognized on the balance sheets. In 2013, 2012, and 2011, the Company incurred fuel expense of \$1.6 billion, \$1.5 billion, and \$1.7 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 capacity expense under PPAs accounted for as operating leases was \$30 million, \$33 million, and \$33 million for 2013, 2012, and 2011, respectively. Total estimated minimum long-term obligations at December 31, 2013 were as follows:

	Operating Lease PPAs	
	<i>(in millions)</i>	
2014	\$	36
2015		38
2016		39
2017		40
2018		42
2019 and thereafter		182
<b>Total commitments</b>	<b>\$</b>	<b>377</b>

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. Accordingly, Southern Company has entered into

**NOTES (continued)**  
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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 \$21 million in 2013, \$24 million in 2012, and \$23 million in 2011. Of these amounts, \$18 million, \$19 million, and \$18 million for 2013, 2012, and 2011, respectively, relate to the railcar leases and are recoverable through the Company's Rate ECR. As of December 31, 2013, estimated minimum lease payments under operating leases were as follows:

	<b>Minimum Lease Payments</b>		
	<b>Railcars</b>	<b>Vehicles &amp; Other</b>	<b>Total</b>
	<i>(in millions)</i>		
2014	\$ 12	\$ 3	\$ 15
2015	10	2	12
2016	11	1	12
2017	6	—	6
2018	4	—	4
2019 and thereafter	15	—	15
<b>Total</b>	<b>\$ 58</b>	<b>\$ 6</b>	<b>\$ 64</b>

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 2023 with maximum obligations under these leases of \$8 million in 2014, \$5 million in 2015, \$4 million in 2016, and \$12 million in 2019 and thereafter. There are no maximum obligations under these leases in 2017 and 2018. 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**

The Company has guaranteed the obligation of SEGCO for \$25 million of pollution control revenue bonds issued in 2001, which mature in June 2019, and also \$100 million of senior notes issued in November 2013, which mature in December 2018. Georgia Power has agreed to reimburse the Company for the pro rata portion of such obligations corresponding to Georgia Power's then proportionate ownership of SEGCO's stock if the Company is called upon to make such payment under its guarantee. See Note 4 for additional information.

**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, 2013, there were approximately 1,000 current and former employees of the Company participating in the stock option program, and there were 28 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. Stock options held by employees of a company undergoing a change in control vest upon the change in control.

**NOTES (continued)**  
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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:

<b>Year Ended December 31</b>	<b>2013</b>	2012	2011
Expected volatility	<b>16.6%</b>	17.7%	17.5%
Expected term <i>(in years)</i>	<b>5.0</b>	5.0	5.0
Interest rate	<b>0.9%</b>	0.9%	2.3%
Dividend yield	<b>4.4%</b>	4.2%	4.8%
Weighted average grant-date fair value	<b>\$2.93</b>	\$3.39	\$3.23

The Company's activity in the stock option program for 2013 is summarized below:

	<b>Shares Subject to Option</b>	<b>Weighted Average Exercise Price</b>
Outstanding at December 31, 2012	6,060,552	\$ 36.02
Granted	1,319,038	44.07
Exercised	(1,035,611)	32.74
Cancelled	(4,271)	42.88
<b>Outstanding at December 31, 2013</b>	<b>6,339,708</b>	<b>\$ 38.23</b>
<b>Exercisable at December 31, 2013</b>	<b>4,021,541</b>	<b>\$ 35.29</b>

The number of stock options vested, and expected to vest in the future, as of December 31, 2013 was not significantly different from the number of stock options outstanding at December 31, 2013 as stated above. As of December 31, 2013, 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 \$26 million and \$25 million, respectively.

As of December 31, 2013, 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, 2013, 2012, and 2011, total compensation cost for stock option awards recognized in income was \$4 million, \$4 million, and \$3 million, respectively, with the related tax benefit also recognized in income of \$2 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, 2013, 2012, and 2011 was \$11 million, \$28 million, and \$23 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled \$4 million, \$11 million, and \$9 million for the years ended December 31, 2013, 2012, and 2011, 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.

## NOTES (continued)

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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:

<b>Year Ended December 31</b>	<b>2013</b>	2012	2011
Expected volatility	<b>12.0%</b>	16%	19.2%
Expected term ( <i>in years</i> )	<b>3.0</b>	3.0	3.0
Interest rate	<b>0.4%</b>	0.4%	1.4%
Annualized dividend rate	<b>\$1.96</b>	\$1.89	\$1.82
Weighted average grant-date fair value	<b>\$40.50</b>	\$41.99	\$35.97

Total unvested performance share units outstanding as of December 31, 2012 were 280,536. During 2013, 141,355 performance share units were granted, 131,581 performance share units were vested, and 5,484 performance share units were forfeited resulting in 284,826 unvested units outstanding at December 31, 2013. In January 2014, the vested performance share award units were converted into 39,258 shares outstanding at a share price of \$41.27 for the three-year performance and vesting period ended December 31, 2013.

For the years ended December 31, 2013, 2012, and 2011, total compensation cost for performance share units recognized in income was \$5 million, \$5 million, and \$3 million, respectively, with the related tax benefit also recognized in income of \$2 million, \$2 million, and \$1 million, respectively. As of December 31, 2013, there was \$6 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 \$13.6 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 \$127 million per incident for each licensed reactor it operates but not more than an aggregate of \$19 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 \$255 million per incident but not more than an aggregate of \$38 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 September 10, 2018.

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 NEIL policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to \$2.25 billion for nuclear losses in excess of the \$500 million primary coverage. These policies have a sublimit of \$1.7 billion for non-nuclear losses.

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 limits based on the projected full cost of replacement power and has elected a 12-week deductible waiting period.

Under each of the NEIL policies, members are subject to assessments each year if losses exceed the accumulated funds available to the insurer. The current maximum annual assessments for the Company under the NEIL policies would be \$43 million.

## **NOTES (continued)**

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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.

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As of December 31, 2013, 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:

As of December 31, 2013:	Fair Value Measurements Using			Total
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	
<i>(in millions)</i>				
Assets:				
Energy-related derivatives	\$ —	\$ 7	\$ —	\$ 7
Nuclear decommissioning trusts: <sup>(a)</sup>				
Domestic equity	392	74	—	466
Foreign equity	35	65	—	100
U.S. Treasury and government agency securities	—	24	—	24
Corporate bonds	—	89	—	89
Mortgage and asset backed securities	—	18	—	18
Other investments	—	13	3	16
Cash equivalents	236	—	—	236
<b>Total</b>	<b>\$ 663</b>	<b>\$ 290</b>	<b>\$ 3</b>	<b>\$ 956</b>
Liabilities:				
Energy-related derivatives	\$ —	\$ 8	\$ —	\$ 8

(a) Excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases. See Note 1 under "Nuclear Decommissioning" for additional information.

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:

As of December 31, 2012:	Fair Value Measurements Using			Total
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	
<i>(in millions)</i>				
Assets:				
Energy-related derivatives	\$ —	\$ 5	\$ —	\$ 5
Nuclear decommissioning trusts: <sup>(a)</sup>				
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
<b>Total</b>	<b>\$ 319</b>	<b>\$ 290</b>	<b>\$ —</b>	<b>\$ 609</b>
Liabilities:				
Energy-related derivatives	\$ —	\$ 18	\$ —	\$ 18

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

**NOTES (continued)**  
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**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 Overnight Index Swap 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. Other 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 these assets using various inputs and techniques depending on the nature of the underlying investments. The fair value of partnerships is determined by aggregating the value of the underlying assets.

A market price secured from the primary source vendor is 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, 2013 and 2012, 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:

	<b>Fair Value</b>	<b>Unfunded Commitments</b>	<b>Redemption Frequency</b>	<b>Redemption Notice Period</b>
<b>As of December 31, 2013:</b>	<i>(in millions)</i>			
Nuclear decommissioning trusts:				
Equity-commingled funds	\$65	None	Daily/Monthly	Daily/7 Days
Trust-owned life insurance	110	None	Daily	15 days
Cash equivalents:				
Money market funds	236	None	Daily	Not applicable
<b>As of December 31, 2012:</b>				
Nuclear decommissioning trusts:				
Equity-commingled funds	\$55	None	Daily/Monthly	Daily/7 days
Trust-owned life insurance	96	None	Daily	15 days

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.

**NOTES (continued)**  
**Alabama Power Company 2013 Annual Report**

As of December 31, 2013 and 2012, other financial instruments for which the carrying amount did not equal fair value were as follows:

	<b>Carrying Amount</b>	<b>Fair Value</b>
	<i>(in millions)</i>	
Long-term debt:		
<b>2013</b>	<b>\$ 6,228</b>	<b>\$ 6,534</b>
2012	\$ 6,179	\$ 6,899

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. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities.

**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.

**NOTES (continued)**  
**Alabama Power Company 2013 Annual Report**

At December 31, 2013, the net volume of energy-related derivative contracts for natural gas positions for the Company, together with the longest hedge date over which it is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest date for derivatives not designated as hedges, were as follows:

Net Purchased mmBtu*	Longest Hedge Date	Longest Non-Hedge Date
<i>(in millions)</i> 69	2017	—

\* million British thermal units (mmBtu)

For cash flow hedges, the amounts expected to be reclassified from accumulated OCI to revenue and fuel expense for the 12-month period ending December 31, 2014 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, 2013, there were no interest rate derivatives outstanding.

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2014 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, 2013 and 2012, the fair value of energy-related derivatives was reflected in the balance sheets as follows:

Derivative Category	Asset Derivatives		Liability Derivatives			
	Balance Sheet Location	2013	2012	Balance Sheet Location	2013	2012
		<i>(in millions)</i>			<i>(in millions)</i>	
<b>Derivatives designated as hedging instruments for regulatory purposes</b>						
Energy-related derivatives:						
	Other current assets	\$ 5	\$ 2	Liabilities from risk management activities	\$ 3	\$ 14
	Other deferred charges and assets	2	3	Other deferred credits and liabilities	5	4
<b>Total derivatives designated as hedging instruments for regulatory purposes</b>		<b>\$ 7</b>	<b>\$ 5</b>		<b>\$ 8</b>	<b>\$ 18</b>
<b>Total</b>		<b>\$ 7</b>	<b>\$ 5</b>		<b>\$ 8</b>	<b>\$ 18</b>

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

**NOTES (continued)**  
**Alabama Power Company 2013 Annual Report**

The derivative contracts of the Company are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related and interest rate derivative contracts contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Amounts related to energy-related derivative contracts at December 31, 2013 and 2012 are presented in the following tables.

<b>Assets</b>	<b>Fair Value</b>				
	<b>2013</b>	<b>2012</b>	<b>Liabilities</b>	<b>2013</b>	<b>2012</b>
	<i>(in millions)</i>			<i>(in millions)</i>	
Energy-related derivatives presented in the Balance Sheet <sup>(a)</sup>	\$ 7	\$ 5	Energy-related derivatives presented in the Balance Sheet <sup>(a)</sup>	\$ 8	\$ 18
Gross amounts not offset in the Balance Sheet <sup>(b)</sup>	(5)	(4)	Gross amounts not offset in the Balance Sheet <sup>(b)</sup>	(5)	(4)
<b>Net-energy related derivative assets</b>	<b>\$ 2</b>	<b>\$ 1</b>	<b>Net-energy related derivative liabilities</b>	<b>\$ 3</b>	<b>\$ 14</b>

(a) The Company does not offset fair value amounts for multiple derivative instruments executed with the same counterparty on the balance sheets; therefore, gross and net amounts of derivative assets and liabilities presented on the balance sheets are the same.

(b) Includes gross amounts subject to netting terms that are not offset on the balance sheets and any cash/financial collateral pledged or received.

At December 31, 2013 and 2012, 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:

<b>Derivative Category</b>	<b>Unrealized Losses</b>			<b>Unrealized Gains</b>		
	<b>Balance Sheet Location</b>	<b>2013</b>	<b>2012</b>	<b>Balance Sheet Location</b>	<b>2013</b>	<b>2012</b>
		<i>(in millions)</i>			<i>(in millions)</i>	
Energy-related derivatives:	Other regulatory assets, current	\$ (3)	\$ (14)	Other current liabilities	\$ 5	\$ 2
	Other regulatory assets, deferred	(5)	(4)	Other regulatory liabilities, deferred	2	3
<b>Total energy-related derivative gains (losses)</b>		<b>\$ (8)</b>	<b>\$ (18)</b>		<b>\$ 7</b>	<b>\$ 5</b>

For the years ended December 31, 2013, 2012, and 2011, the pre-tax effect of interest rate derivatives designated as cash flow hedging instruments on the statements of income was as follows:

<b>Derivatives in Cash Flow Hedging Relationships</b>	<b>Gain (Loss) Recognized in OCI on Derivative (Effective Portion)</b>			<b>Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)</b>			
	<b>2013</b>	<b>2012</b>	<b>2011</b>	<b>Amount</b>			
<b>Derivative Category</b>	<b>2013</b>	<b>2012</b>	<b>2011</b>	<b>Statements of Income Location</b>			
	<i>(in millions)</i>			<i>(in millions)</i>			
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, 2013, 2012, and 2011, 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, 2013, the fair value of derivative liabilities with contingent features was \$1 million.

**NOTES (continued)**

**Alabama Power Company 2013 Annual Report**

The Company's collateral posted with its derivative counterparties at December 31, 2013 was not material. 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 \$9 million. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty.

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.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's Investors Services, Inc. and Standard and Poor's Ratings Services, a division of The McGraw Hill Companies, Inc. or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

**NOTES (continued)**  
**Alabama Power Company 2013 Annual Report**

**12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)**

Summarized quarterly financial information for 2013 and 2012 is as follows:

<b>Quarter Ended</b>	<b>Operating Revenues</b>	<b>Operating Income</b>	<b>Net Income After Dividends on Preferred and Preference Stock</b>
		<i>(in millions)</i>	
<b>March 2013</b>	\$ 1,308	\$ 307	\$ 141
<b>June 2013</b>	1,392	357	173
<b>September 2013</b>	1,604	500	258
<b>December 2013</b>	1,314	312	140
March 2012	\$ 1,216	\$ 291	\$ 126
June 2012	1,377	390	185
September 2012	1,637	544	280
December 2012	1,290	271	113

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

**SELECTED FINANCIAL AND OPERATING DATA 2009-2013**  
**Alabama Power Company 2013 Annual Report**

	2013	2012	2011	2010	2009
<b>Operating Revenues (in millions)</b>	\$ 5,618	\$ 5,520	\$ 5,702	\$ 5,976	\$ 5,529
<b>Net Income After Dividends on Preferred and Preference Stock (in millions)</b>	\$ 712	\$ 704	\$ 708	\$ 707	\$ 670
<b>Cash Dividends on Common Stock (in millions)</b>	\$ 644	\$ 684	\$ 774	\$ 586	\$ 523
<b>Return on Average Common Equity (percent)</b>	13.07	13.10	13.19	13.31	13.27
<b>Total Assets (in millions)</b>	\$ 19,251	\$ 18,712	\$ 18,477	\$ 17,994	\$ 17,524
<b>Gross Property Additions (in millions)</b>	\$ 1,204	\$ 940	\$ 1,016	\$ 956	\$ 1,323
<b>Capitalization (in millions):</b>					
Common stock equity	\$ 5,502	\$ 5,398	\$ 5,342	\$ 5,393	\$ 5,237
Preference stock	343	343	343	343	343
Redeemable preferred stock	342	342	342	342	342
Long-term debt	6,233	5,929	5,632	5,987	6,082
Total (excluding amounts due within one year)	\$ 12,420	\$ 12,012	\$ 11,659	\$ 12,065	\$ 12,004
<b>Capitalization Ratios (percent):</b>					
Common stock equity	44.3	44.9	45.8	44.7	43.6
Preference stock	2.8	2.9	2.9	2.9	2.9
Redeemable preferred stock	2.7	2.8	2.9	2.8	2.8
Long-term debt	50.2	49.4	48.4	49.6	50.7
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0
<b>Customers (year-end):</b>					
Residential	1,241,998	1,237,730	1,231,574	1,235,128	1,229,134
Commercial	196,209	196,177	196,270	197,336	198,642
Industrial	5,851	5,839	5,844	5,770	5,912
Other	751	748	746	782	780
Total	1,444,809	1,440,494	1,434,434	1,439,016	1,434,468
<b>Employees (year-end)</b>	6,896	6,778	6,632	6,552	6,842

**SELECTED FINANCIAL AND OPERATING DATA 2009-2013 (continued)**  
**Alabama Power Company 2013 Annual Report**

	2013	2012	2011	2010	2009
<b>Operating Revenues (in millions):</b>					
Residential	\$ 2,079	\$ 2,068	\$ 2,144	\$ 2,283	\$ 1,962
Commercial	1,477	1,491	1,495	1,535	1,430
Industrial	1,369	1,346	1,306	1,231	1,080
Other	27	28	27	27	25
Total retail	4,952	4,933	4,972	5,076	4,497
Wholesale — non-affiliates	248	277	287	465	620
Wholesale — affiliates	212	111	244	236	237
Total revenues from sales of electricity	5,412	5,321	5,503	5,777	5,354
Other revenues	206	199	199	199	175
Total	\$ 5,618	\$ 5,520	\$ 5,702	\$ 5,976	\$ 5,529
<b>Kilowatt-Hour Sales (in millions):</b>					
Residential	17,920	17,612	18,650	20,417	18,071
Commercial	13,892	13,963	14,173	14,719	14,186
Industrial	22,904	22,158	21,666	20,622	18,555
Other	211	214	214	216	218
Total retail	54,927	53,947	54,703	55,974	51,030
Wholesale — non-affiliates	3,711	4,196	4,330	8,655	14,317
Wholesale — affiliates	7,672	4,279	7,211	6,074	6,473
Total	66,310	62,422	66,244	70,703	71,820
<b>Average Revenue Per Kilowatt-Hour (cents):</b>					
Residential	11.60	11.74	11.50	11.18	10.86
Commercial	10.63	10.68	10.55	10.43	10.08
Industrial	5.98	6.07	6.03	5.97	5.82
Total retail	9.02	9.14	9.09	9.07	8.81
Wholesale	4.04	4.58	4.60	4.76	4.12
Total sales	8.16	8.52	8.31	8.17	7.45
<b>Residential Average Annual Kilowatt-Hour Use Per Customer</b>	14,451	14,252	15,138	16,570	14,716
<b>Residential Average Annual Revenue Per Customer</b>	\$ 1,676	\$ 1,674	\$ 1,740	\$ 1,853	\$ 1,597
<b>Plant Nameplate Capacity Ratings (year-end) (megawatts)</b>	12,222	12,222	12,222	12,222	12,222
<b>Maximum Peak-Hour Demand (megawatts):</b>					
Winter	9,347	10,285	11,553	11,349	10,701
Summer	10,692	11,096	11,500	11,488	10,870
<b>Annual Load Factor (percent)</b>	64.9	61.3	60.6	62.6	59.8
<b>Plant Availability (percent)*:</b>					
Fossil-steam	87.3	88.6	88.7	92.9	88.5
Nuclear	90.7	94.5	94.7	88.4	93.3
<b>Source of Energy Supply (percent):</b>					
Coal	50.0	48.2	52.5	56.6	53.4
Nuclear	20.3	22.6	20.8	17.7	18.6
Hydro	8.1	4.1	4.6	5.0	7.9
Gas	15.7	16.8	15.3	14.0	11.8
Purchased power —					
From non-affiliates	2.9	2.0	0.9	1.6	2.0
From affiliates	3.0	6.3	5.9	5.1	6.3
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 2013 Annual Report

#### Directors

**Whit Armstrong**  
Managing Member,  
Creeke Capital Investments, LLC

**Ralph D. Cook**  
City Attorney,  
City of Birmingham

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

**Mark A. Crosswhite<sup>1</sup>**  
President and Chief Executive  
Officer, Alabama Power Company

**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<sup>1,2</sup>**  
Chairman,  
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<sup>1,2</sup>**  
Chairman

**Mark A. Crosswhite<sup>1</sup>**  
President and Chief Executive  
Officer

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

**Zeke W. Smith**  
Executive Vice President

**Steven R. Spencer**  
Executive Vice President

**James P. Heilbron**  
Senior Vice President and Senior  
Production Officer

**Gordon G. Martin**  
Senior Vice President and General  
Counsel

**Gregory J. Barker**  
Senior Vice President

**Anita Allcorn-Walker**  
Vice President and Comptroller

**William E. Zales, Jr.<sup>3</sup>**  
Vice President, Corporate  
Secretary, and Assistant Treasurer

**Kathleen S. King<sup>4</sup>**  
Vice President, Chief Information  
Officer

**C. David Cox<sup>5</sup>**  
Vice President

**Ronald Q. Patterson<sup>6</sup>**  
Vice President and Assistant  
Treasurer

**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

**R. Scott Moore**  
Vice President

**Kenneth F. Novak**  
Vice President

**Jonathan K. Porter<sup>7</sup>**  
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<sup>8</sup>**  
Vice President

**Robert L. Weaver**  
Vice President

**Ceila H. Shorts<sup>6</sup>**  
Corporate Secretary

**Wendy M. Hoomes<sup>6</sup>**  
Assistant Comptroller

**Melissa K. Caen**  
Assistant Secretary and  
Assistant Treasurer

**Amy E. Blankenship<sup>6</sup>**  
Assistant Secretary

**Kay I. Worley<sup>9</sup>**  
Assistant Secretary

**Christopher R. Blake**  
Assistant Treasurer

<sup>1</sup> Effective 3/2014

<sup>2</sup> Resigned as President and  
Chief Executive Officer  
effective 3/2014

<sup>3</sup> Retired 6/2013

<sup>4</sup> Resigned 4/2013

<sup>5</sup> Effective 8/2013

<sup>6</sup> Effective 6/2013

<sup>7</sup> Effective 2/2014

<sup>8</sup> Retired 2/2014

<sup>9</sup> Retired 9/2013

## **CORPORATE INFORMATION**

### **Alabama Power Company 2013 Annual Report**

#### **General**

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

#### **Profile**

The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Alabama and to wholesale customers in the Southeast. The Company sells electricity to more than 1.4 million customers within its service area of approximately 45,000 square miles. In 2013, retail energy sales accounted for 83 percent of the Company's total sales of 66 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 20<sup>th</sup> Street, Suite 950  
Birmingham, AL 35203

#### **Registrar, Transfer Agent, and Dividend Paying Agent**

All series of Preferred and Preference Stock  
Computershare Inc.  
P.O. Box 43006  
Providence, RI 02940-3006  
(800) 554-7626

[www.computershare.com/investor](http://www.computershare.com/investor)

Number of Preferred Shareholders of record as of December 31, 2013 was 949.

#### **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) 257-2619.

#### **Alabama Power Company**

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Birmingham, AL 35203  
(205) 257-1000  
[www.alabamapower.com](http://www.alabamapower.com)

#### **Auditors**

Deloitte & Touche LLP  
420 North 20<sup>th</sup> Street  
Suite 2400  
Birmingham, AL 35203

#### **Legal Counsel**

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

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