GEORGIA POWER COMPANY

2013 ANNUAL REPORT

GEORGIA POWER

A SOUTHERN COMPANY

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Georgia Power Company 2013 Annual Report

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

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework (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.

W. Paul Bowers
President and Chief Executive Officer

W. Ron Hinson
Executive Vice President, Chief Financial Officer, and Treasurer

February 27, 2014

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Georgia Power Company

We have audited the accompanying balance sheets and statements of capitalization of Georgia Power Company (the Company) (a wholly owned subsidiary of 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 31 to 81) present fairly, in all material respects, the financial position of Georgia 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

Atlanta, Georgia
February 27, 2014

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Georgia Power Company 2013 Annual Report

OVERVIEW

Business Activities

Georgia Power Company (the Company) operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales given economic conditions, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, reliability, and fuel. In addition, the Company is currently constructing two new nuclear generating units at Plant Vogtle (Plant Vogtle Units 3 and 4) to increase its generation diversity and meet future supply needs. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.

On December 17, 2013, the Georgia Public Service Commission (PSC) approved an Alternate Rate Plan for the years 2014 through 2016 (2013 ARP), including base rate increases of approximately $110 million, $187 million, and $170 million effective January 1, 2014, 2015, and 2016, respectively. The Company is scheduled to file its next base rate case by July 1, 2016. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Rate Plans" herein for additional information.

Key Performance Indicators

The Company continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, the execution of major construction projects, 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 2013 Peak Season EFOR did not meet the target due to an explosion at Plant Bowen in April 2013. See FUTURE EARNINGS POTENTIAL – "Other Matters" herein for additional information. Transmission and distribution system reliability performance is measured by the frequency and duration of outages, with performance targets set based on historical performance. The 2013 performance was better than the target for these reliability measures.

Net income after dividends on preferred and preference stock is the primary measure of the Company's financial performance. The Company's 2013 results compared to its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2013 Target Performance	2013 Actual Performance
Customer Satisfaction	Top quartile in customer surveys	Top quartile
Peak Season EFOR — fossil/hydro	5.86% or less	9.55%
Net Income After Dividends on Preferred and Preference Stock	$1.19 billion	$1.17 billion

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The 2013 net income after dividends on preferred and preference stock did not meet the target due to significantly milder than normal weather.

Earnings

The Company's 2013 net income after dividends on preferred and preference stock totaled $1.2 billion, representing a $6 million, or 0.5%, increase over the previous year. The increase was due primarily to an increase related to retail revenue rate effects, partially offset by milder weather in 2013, an increase in depreciation and amortization, and higher income taxes.

The Company's 2012 net income after dividends on preferred and preference stock totaled $1.2 billion representing a $23 million, or 2.0%, increase over the previous year. The increase was due primarily to lower operations and maintenance expenses resulting from cost containment efforts in 2012 and retail revenue rate effects as authorized by the Georgia PSC under the Alternate Rate Plan for the years 2011 through 2013 (2010 ARP). These increases were partially offset by lower operating revenues as a result of milder weather in 2012 and a decrease in customer usage, lower allowance for funds used during construction (AFUDC) equity, higher depreciation and amortization, primarily as a result of completing construction of Plant McDonough-Atkinson Units 4 and 5, higher income taxes, and higher interest expense reflecting a 2011 settlement of tax litigation with the Georgia Department of Revenue (DOR).

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

	Amount	Increase (Decrease) from Prior Year	
	2013	**2013**	2012
		(in millions)	
Operating revenues	**$ 8,274**	**$ 276**	$ (802)
Fuel	**2,307**	**256**	(738)
Purchased power	**884**	**(97)**	(122)
Other operations and maintenance	**1,654**	**10**	(133)
Depreciation and amortization	**807**	**62**	30
Taxes other than income taxes	**382**	**8**	5
Total operating expenses	**6,034**	**239**	(958)
Operating income	**2,240**	**37**	156
Allowance for equity funds used during construction	**30**	**(23)**	(43)
Interest expense, net of amounts capitalized	**361**	**(5)**	23
Other income (expense), net	**5**	**22**	(4)
Income taxes	**723**	**35**	63
Net income	**1,191**	**6**	23
Dividends on preferred and preference stock	**17**	**—**	—
Net income after dividends on preferred and preference stock	**$ 1,174**	**$ 6**	$ 23

Operating Revenues

Operating revenues for 2013 were $8.3 billion, reflecting a $276 million increase from 2012. Details of operating revenues were as follows:

	Amount	
	2013	2012
	(in millions)	
Retail — prior year	**$ 7,362**	$ 8,099
Estimated change resulting from —		
Rates and pricing	**137**	166
Sales growth (decline)	**(5)**	(26)
Weather	**(61)**	(147)
Fuel cost recovery	**187**	(730)
Retail — current year	**7,620**	7,362
Wholesale revenues —		
Non-affiliates	**281**	281
Affiliates	**20**	20
Total wholesale revenues	**301**	301
Other operating revenues	**353**	335
Total operating revenues	**$ 8,274**	$ 7,998
Percent change	**3.5%**	(9.1)%

Retail base revenues of $4.9 billion in 2013 increased $71 million, or 1.5%, compared to 2012 primarily due to base tariff increases effective April 1, 2012 and January 1, 2013, as approved by the Georgia PSC, related to placing new generating units at Plant McDonough-Atkinson in service and collecting financing costs related to the construction of Plant Vogtle Units 3 and 4 through the Nuclear Construction Cost Recovery (NCCR) tariff, as well as higher contributions from market-driven rates from commercial and industrial customers. The increase was partially offset by milder weather in 2013 as compared to 2012. In 2013, residential base revenues decreased $3 million, or 0.1%, commercial base revenues increased $43 million, or 2.2%, and industrial base revenues increased $28 million, or 4.4%, compared to 2012. Residential usage continues to be impacted by economic uncertainty, modest economic growth, and energy efficiency efforts.

Retail base revenues of $4.8 billion in 2012 were flat compared to 2011 primarily due to milder weather in 2012, decreased customer usage, and lower contributions from market-driven rates from commercial and industrial customers, offset by base tariff increases effective April 1, 2012 related to placing Plant McDonough-Atkinson Units 4 and 5 in service, collecting financing costs related to the construction of Plant Vogtle Units 3 and 4 through the NCCR tariff, and demand-side management programs effective January 1, 2012, as approved by the Georgia PSC, as well as the rate pricing effect of decreased customer usage. In 2012, residential base revenues increased $17 million, or 0.8%, commercial base revenues increased $11 million, or 0.6%, and industrial base revenues decreased $36 million, or 5.4%, compared to 2011. Economic uncertainty impacted residential, commercial, and industrial base revenues.

See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (decline) and weather.

Electric rates include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these fuel cost recovery provisions, fuel revenues generally equal fuel expenses and do not affect net income. The Company further lowered fuel rates effective January 1, 2013. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information.

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

	2013	2012	2011
		(in millions)	
Capacity and other	**$ 174**	$ 177	$ 177
Energy	**107**	104	164
Total non-affiliated	**$ 281**	$ 281	$ 341

Wholesale revenues from sales to non-affiliates consist of power purchase agreements (PPA) and short-term opportunity sales. Capacity revenues reflect the recovery of fixed costs and a return on investment. Wholesale revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of 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 the 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. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost of energy.

Revenues from other non-affiliated sales were flat in 2013 and decreased $60 million, or 17.6%, in 2012. The decrease in 2012 was primarily due to a 24.9% decrease in kilowatt-hour (KWH) sales due to lower demand resulting from milder weather and the availability of market energy at a lower cost than Company-owned generation.

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 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. In 2013, wholesale revenues from sales to affiliates remained flat and decreased $12 million in 2012 due to a decrease of 4.2% in KWH sales as a result of lower demand because the market cost of available energy was lower than the cost of Company-owned generation. In 2012, lower demand also resulted from the milder weather.

Other operating revenues increased $18 million, or 5.4%, in 2013 from the prior year primarily due to higher revenues from transmission, pole attachments, and outdoor lighting. Other operating revenues increased $7 million, or 2.1%, in 2012 from the prior year primarily due to higher revenues from outdoor lighting and pole attachments.

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:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2013	**2013**	2012	**2013***	2012
	(in billions)				
Residential	**25.5**	**(1.0)%**	(5.4)%	**0.1%**	0.3 %
Commercial	**32.0**	**(0.9)**	(1.9)	**(0.2)**	(0.6)
Industrial	**23.1**	**—**	(1.8)	**0.7**	(1.2)
Other	**0.6**	**(1.8)**	(2.5)	**(1.8)**	(2.0)
Total retail	**81.2**	**(0.7)**	(3.0)	**0.1%**	(0.5)%
Wholesale					
Non-affiliates	**3.0**	**3.3**	(24.9)		
Affiliates	**0.5**	**(17.4)**	(4.2)		
Total wholesale	**3.5**	**(0.2)**	(22.0)		
Total energy sales	**84.7**	**(0.7)%**	(4.0)%		

* In the first quarter 2012, the Company began using new actual advanced meter data to compute unbilled revenues. The weather-adjusted KWH sales variances shown above reflect an adjustment to the estimated allocation of the Company's unbilled January 2012 KWH sales among customer classes that is consistent with the actual allocation in 2013. Without this adjustment, 2013 weather-adjusted residential KWH sales decreased 0.4% as compared to 2012 while weather-adjusted commercial KWH sales increased 0.2% as compared to 2012.

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

In 2013, KWH sales for residential and commercial customer classes decreased compared to 2012 primarily due to milder weather in 2013. Industrial sales were flat in 2013 compared to 2012. Increased demand in the paper, textiles, and stone, clay, and glass sectors were the main contributors to the increase in weather-adjusted industrial sales.

In 2012, KWH sales for all customer classes decreased compared to 2011 primarily due to milder weather in 2012. Economic uncertainty continues to impact sales for all customer classes as well; however, an increase of approximately 15,000 new residential customers in 2012 contributed to a slight increase in weather-adjusted residential KWH sales.

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

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

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

	2013	2012	2011
Total generation *(billions of KWHs)*	**66.8**	59.8	65.5
Total purchased power *(billions of KWHs)*	**21.4**	28.7	26.8
Sources of generation *(percent)* -			
Coal	**35**	39	62
Nuclear	**23**	27	23
Gas	**39**	33	13
Hydro	**3**	1	2
Cost of fuel, generated *(cents per net KWH)* -			
Coal	**4.92**	4.63	4.70
Nuclear	**0.91**	0.87	0.78
Gas	**3.33**	3.02	4.92
Average cost of fuel, generated *(cents per net KWH)*	**3.32**	3.07	3.80
Average cost of purchased power *(cents per net KWH)* *	**4.83**	4.24	5.38

* 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 $3.2 billion in 2013, an increase of $159 million, or 5.2%, compared to 2012. The increase was primarily due to a $284 million increase in the average cost of fuel and purchased power primarily due to higher natural gas prices and a $185 million increase due to an increase in the volume of KWHs generated, partially offset by a $310 million decrease due to a decrease in the volume of KWHs purchased, as the cost of Company-owned generation was lower than the market cost of available energy.

Fuel and purchased power expenses were $3.0 billion in 2012, a decrease of $860 million, or 22.1%, compared to 2011. The decrease was primarily due to a $703 million decrease in the average cost of fuel and purchased power primarily due to lower natural gas prices and a $259 million decrease due to a decrease in the volume of KWHs generated as a result of lower customer demand from milder weather in 2012. These decreases were partially offset by a $102 million increase due to an increase in the volume of KWHs purchased, as the market cost of available energy was lower than the additional Company-owned generation available.

Fuel and purchased power energy transactions do not have a significant impact on earnings since these fuel expenses are generally offset by fuel revenues through the Company's fuel cost recovery mechanism. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information.

Fuel

Fuel expense was $2.3 billion in 2013, an increase of $256 million, or 12.5%, compared to 2012. The increase was primarily due to a 9.9% increase in the volume of KWHs generated as a result of higher prices for purchased power and an 8.1% increase in the average cost of fuel per KWH generated for all types of fuel generation, partially offset by a 191.0% increase in the volume of KWHs generated by hydro facilities resulting from greater rainfall. Fuel expense was $2.1 billion in 2012, a decrease of $738 million, or 26.5%, compared to 2011. The decrease was primarily due to an 8.4% decrease in KWHs generated as a result of lower demand and a 19.2% decrease in the average cost of fuel per KWH generated primarily due to lower natural gas prices. In addition, the Company's fuel mix for generation changed from 62% coal and 13% natural gas in 2011 to 39% coal and 33% natural gas in 2012 primarily due to the completion of the Plant McDonough-Atkinson combined cycle units.

Purchased Power - Non-Affiliates

Purchased power expense from non-affiliates was $224 million in 2013, a decrease of $91 million, or 28.9%, compared to 2012. The decrease was primarily due to a 52.0% decrease in the volume of KWHs purchased as the cost of Company-owned generation was lower than the market cost of available energy, partially offset by an increase of 41.5% in the average cost per KWH purchased primarily due to higher fuel prices. Purchased power expense from non-affiliates was $315 million in 2012, a decrease of $75 million, or 19.2%, compared to 2011. The decrease was due to a 23.8% decrease in the average cost per KWH purchased primarily due to lower natural gas prices, partially offset by a 7.0% increase in the volume of KWHs purchased, as the market cost of available energy was lower than the cost of additional Company-owned generation.

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

Purchased Power - Affiliates

Purchased power expense from affiliates was $660 million in 2013, a decrease of $6 million, or 0.9%, compared to 2012. The decrease was primarily due to an 18.4% decrease in the volume of KWHs purchased as the Company's units generally dispatched at a lower cost than other Southern Company system resources, partially offset by a 12.6% increase in the average cost per KWH purchased reflecting higher fuel prices. Purchased power expense from affiliates was $666 million in 2012, a decrease of $47 million, or 6.6%, compared to 2011. The decrease was primarily due to a 20.2% decrease in the average cost per KWH purchased, reflecting lower natural gas prices, partially offset by a 7.1% increase in the volume of KWHs purchased as the cost of the available energy was lower than the cost of Company-owned generation available.

Energy purchases from affiliates will vary depending on the demand 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, all as approved by the FERC.

Other Operations and Maintenance Expenses

In 2013, other operations and maintenance expenses increased $10 million, or 0.6%, compared to 2012. The increase was primarily due to an increase of $33 million in pension and other employee benefit-related expenses and $13 million in transmission system load expense resulting from billing adjustments with integrated transmission system owners, partially offset by a decrease of $38 million in fossil generating expenses due to cost containment and outage timing to offset milder weather in 2013 as compared to 2012 and the effect of economic uncertainty.

In 2012, other operations and maintenance expenses decreased $133 million, or 7.5%, compared to 2011. The decrease was primarily due to the timing of planned generation outages and decreases in transmission and distribution maintenance as a result of cost containment efforts to offset the effects of milder weather in 2012 and a decrease in uncollectible account expense of $24 million, as a result of lower revenues, a slightly improving economy, and a change in the customer deposit policy, partially offset by a net increase in pension and other employee benefit-related expenses of $14 million.

Depreciation and Amortization

Depreciation and amortization increased $62 million, or 8.3%, in 2013 compared to 2012. The increase was primarily due to an increase of $64 million in depreciation on additional plant in service due to the completion of Plant McDonough-Atkinson Units 5 and 6 in April 2012 and October 2012, respectively, and depreciation and amortization resulting from certain coal unit retirement decisions (with respect to the portion of such units dedicated to wholesale service). The increase was partially offset by a net reduction in amortization primarily related to amortization of the regulatory liability previously established for state income tax credits, as authorized by the Georgia PSC. See Note 1 to the financial statements under "Regulatory Assets and Liabilities" for additional information on the state income tax credits regulatory liability.

Depreciation and amortization increased $30 million, or 4.2%, in 2012 compared to 2011. The increase was primarily due to an increase of $50 million in depreciation on additional plant in service primarily related to new generation at Plant McDonough-Atkinson Units 4 and 5, partially offset by $27 million in amortization of the regulatory liability for state income tax credits as authorized by the Georgia PSC. See Note 1 to the financial statements under "Regulatory Assets and Liabilities" for additional information.

See Note 1 to the financial statements under "Depreciation and Amortization" for additional information.

Taxes Other Than Income Taxes

In 2013, taxes other than income taxes increased $8 million, or 2.1%, compared to 2012. The increase was primarily due to an increase in property taxes.

In 2012, taxes other than income taxes increased $5 million, or 1.4%, compared to 2011. The increase was primarily due to a $20 million increase in property taxes, partially offset by a $12 million decrease in municipal franchise fees resulting from lower retail revenues in 2012.

Allowance for Funds Used During Construction Equity

AFUDC equity decreased $23 million, or 43.4%, in 2013 compared to the prior year primarily due to the completion of Plant McDonough-Atkinson Units 5 and 6 in April 2012 and October 2012, respectively.

AFUDC equity decreased $43 million, or 44.8%, in 2012 compared to the prior year primarily due to the completion of Plant McDonough-Atkinson Units 4, 5, and 6 in December 2011, April 2012, and October 2012, respectively.

Interest Expense, Net of Amounts Capitalized

In 2013, interest expense, net of amounts capitalized decreased $5 million, or 1.4%, from the prior year. The decrease was primarily due to a $21 million decrease in interest on long-term debt as a result of refinancing activity, partially offset by an $8 million decrease in AFUDC debt primarily due to the completion of Plant McDonough Units 5 and 6 discussed previously and a $9 million increase resulting from the conclusion of certain state and federal income tax audits that reduced interest expense in 2012.

In 2012, interest expense, net of amounts capitalized increased $23 million, or 6.7%, from the prior year primarily due to a $23 million reduction in interest expense in 2011 resulting from the settlement of litigation with the Georgia DOR, a $16 million decrease in AFUDC debt in 2012 primarily due to the completion of Plant McDonough-Atkinson Units 4 and 5 discussed previously, and a net increase of $18 million in interest expense related to outstanding senior notes. The increase was partially offset by reductions in expense related to pollution control revenue bonds, the redemption of all trust preferred securities in September 2011, and the conclusion of certain state and federal income tax audits in 2012 of $13 million, $9 million, and $9 million, respectively.

Other Income (Expense), net

In 2013, other income (expense), net increased $22 million, or 129.4%, from the prior year primarily due to an $8 million increase in wholesale operating fees and a $9 million decrease in donations.

In 2012, other income (expense), net decreased $4 million, or 30.8%, from the prior year. The decrease was not material.

Income Taxes

Income taxes increased $35 million, or 5.1%, in 2013 compared to the prior year primarily due to a decrease in state income tax credits, higher pre-tax earnings, and a decrease in non-taxable AFUDC equity, partially offset by a decrease in non-deductible book depreciation.

Income taxes increased $63 million, or 10.1%, in 2012 compared to the prior year primarily due to higher pre-tax earnings, an increase in non-deductible book depreciation, and a decrease in non-taxable AFUDC equity, partially offset by state income tax credits.

See "Allowance for Funds Used During Construction Equity" herein for additional information.

Effects of Inflation

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

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Georgia PSC under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs and the successful completion of ongoing construction projects, including the construction of Plant Vogtle Units 3 and 4. 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.

In 2013, the Company's generating capacity decreased 398 megawatts (MWs) due to the retirements of Plant Bowen Unit 6 on April 25, 2013, Plant Boulevard Units 2 and 3 on July 17, 2013, and Plant Branch Unit 2 on September 30, 2013. New generating capacity and retirements are approved by the Georgia PSC through the Integrated Resource Plan (IRP) process. See "PSC Matters – Integrated Resource Plans" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Integrated Resource Plans" for additional information.

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. The Company's Environmental Compliance Cost Recovery (ECCR) tariff allows for the recovery of capital and operations and maintenance costs related to environmental controls mandated by state and federal regulations. 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 Gulf Power Company (Gulf 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 related to a unit co-owned by Gulf Power) has been administratively closed in the U.S. District Court for the Northern District of Georgia since 2001.

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 $4.3 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $309 million, $152 million, and $113 million in 2013, 2012, and 2011, respectively. The Company expects that capital expenditures to comply with environmental statutes and regulations will total approximately $1.1 billion from 2014 through 2016, with annual totals of approximately $543 million, $366 million, and $202 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. Based on its preliminary analysis and an assumption that coal combustion residuals will continue to be regulated as non-hazardous solid waste under the proposed rule, the Company does not anticipate that material compliance costs with respect to these proposed rules will be required during the period of 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. See "PSC Matters – Integrated Resource Plans" herein for additional information on planned unit retirements and fuel conversions.

Southern Electric Generating Company (SEGCO), a subsidiary of the Company, is jointly owned with Alabama 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 Alabama Power through a 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 Company's 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 $3.9 billion in reducing and monitoring emissions pursuant to the Clean Air Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone 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. The only area within the Company's service territory designated as a nonattainment area is a 15-county area within metropolitan Atlanta.

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. Redesignation requests for certain areas designated as nonattainment in Georgia are still pending with the EPA. 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_2), 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_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

The Company's service territory is subject to the requirements of the Clean Air Interstate Rule (CAIR), which calls for phased reductions in SO_2 and nitrogen oxide (NO_x) emissions from power plants in 28 eastern states. In 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued decisions invalidating CAIR, but left CAIR compliance requirements in place while the EPA developed a new rule. In 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. Compliance extensions have been granted for some of the Company's affected units.

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 State Implementation Plans (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 Georgia, Alabama, and Florida, 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. The impacts of the eight-hour ozone, fine particulate matter and SO_2 NAAQS, 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.

In addition to the federal air quality laws described above, the Company is also subject to the requirements of the 2007 State of Georgia Multi-Pollutant Rule. The Multi-Pollutant Rule, as amended, is designed to reduce emissions of mercury, SO_2, and NO_x state-wide by requiring the installation of specified control technologies at certain coal-fired generating units by specific dates between December 31, 2008 and April 16, 2015. A companion rule requires a 95% reduction in SO_2 emissions from the controlled units on the same or similar timetable. Through December 31, 2013, the Company had installed the required controls on 13 of its largest coal-fired generating units with projects on three additional units to be completed before the unit-specific installation deadlines.

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.

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 11 electric generating plants with on-site coal combustion residuals, including coal ash and gypsum 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 States of Georgia and Alabama have their own separate 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 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.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. 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 impacted sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Notes 1 and 3 to the financial statements under "Environmental Remediation Recovery" and "Environmental Matters – Environmental Remediation," respectively, for additional information.

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 additional 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 32 million metric tons of carbon dioxide equivalent. The preliminary estimate of the Company's 2013 greenhouse gas emissions on the same basis is approximately 33 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.

PSC Matters

Rate Plans

In 2010, the Georgia PSC approved the 2010 ARP, which resulted in base rate increases of approximately $562 million, $17 million, $125 million, and $74 million effective January 1, 2011, January 1, 2012, April 1, 2012, and January 1, 2013, respectively.

On December 17, 2013, the Georgia PSC voted to approve the 2013 ARP. The 2013 ARP reflects the settlement agreement among the Company, the Georgia PSC's Public Interest Advocacy Staff, and 11 of the 13 intervenors, which was filed with the Georgia PSC on November 18, 2013.

On January 1, 2014, in accordance with the 2013 ARP, the Company increased its tariffs as follows: (1) traditional base tariff rates by approximately $80 million; (2) ECCR tariff by an additional $25 million; (3) Demand-Side Management (DSM) tariffs by an additional $1 million; and (4) Municipal Franchise Fee (MFF) tariff by an additional $4 million, for a total increase in base revenues of approximately $110 million.

Under the 2013 ARP, the following additional rate adjustments will be made to the Company's tariffs in 2015 and 2016 based on annual compliance filings to be made at least 90 days prior to the effective date of the tariffs:

- Effective January 1, 2015 and 2016, the traditional base tariff rates will increase by an estimated $101 million and $36 million, respectively, to recover additional generation capacity-related costs;
- Effective January 1, 2015 and 2016, the ECCR tariff will increase by an estimated $76 million and $131 million, respectively, to recover additional environmental compliance costs;
- Effective January 1, 2015, the DSM tariffs will increase by an estimated $6 million and decrease by an estimated $1 million effective January 1, 2016; and
- The MFF tariff will increase consistent with these adjustments.

The Company currently estimates these adjustments will result in base revenue increases of approximately $187 million in 2015 and $170 million in 2016. The estimated traditional base tariff rate increases for 2015 and 2016 do not include additional Qualifying Facility (QF) PPA expenses; however, compliance filings will include QF PPA expenses for those facilities that are projected to provide capacity to the Company during the following year.

Under the 2013 ARP, the Company's retail return on common equity (ROE) is set at 10.95%, and earnings are evaluated against a retail ROE range of 10.00% to 12.00%. Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by the Company. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. However, if at any time during the term of the 2013 ARP, the Company projects that its retail earnings will be below 10.00% for any calendar year, it may petition the Georgia PSC for implementation of the Interim Cost Recovery (ICR) tariff that would be used to adjust the Company's earnings back to a 10.00% retail ROE. The Georgia PSC would have 90 days to rule on the Company's request. The ICR tariff will expire at the earlier of January 1, 2017 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR tariff, the Company may file a full rate case.

Except as provided above, the Company will not file for a general base rate increase while the 2013 ARP is in effect. The Company is required to file a general rate case by July 1, 2016, in response to which the Georgia PSC would be expected to determine whether the 2013 ARP should be continued, modified, or discontinued.

Integrated Resource Plans

See "Environmental Matters – Environmental Statutes and Regulations – Air Quality," "– Water Quality," and "– Coal Combustion Residuals" and "Rate Plans" herein for additional information regarding proposed and final EPA rules and regulations, including the MATS rule for coal- and oil-fired electric utility steam generating units, revisions to effluent limitations guidelines for steam electric power plants, and additional regulation of coal combustion residuals; the State of Georgia's Multi-Pollutant Rule; the Company's analysis of the potential costs and benefits of installing the required controls on its fossil generating units in light of these regulations; and the Company's latest triennial IRP as approved by the Georgia PSC (2013 IRP).

On January 31, 2013, the Company filed its 2013 IRP. The filing included the Company's request to decertify 16 coal- and oil-fired units totaling 2,093 MWs. Several factors, including the cost to comply with existing and future environmental regulations, recent and forecasted economic conditions, and lower natural gas prices, contributed to the decision to close these units.

On April 17, 2013, the Georgia PSC approved the decertification of Plant Bowen Unit 6 (32 MWs), which was retired on April 25, 2013. On September 30, 2013, Plant Branch Unit 2 (319 MWs) was retired as approved by the Georgia PSC in the 2011 IRP Update (2011 IRP Update) in order to comply with the State of Georgia's Multi-Pollutant Rule.

On July 11, 2013, the Georgia PSC approved the Company's request to decertify and retire Plant Boulevard Units 2 and 3 (28 MWs) effective July 17, 2013. Plant Branch Units 3 and 4 (1,016 MWs), Plant Yates Units 1 through 5 (579 MWs), and Plant McManus Units 1 and 2 (122 MWs) will be decertified and retired by April 16, 2015, the compliance date of the MATS rule. The decertification date of Plant Branch Unit 1 was extended from December 31, 2013 as specified in the final order in the 2011 IRP Update to coincide with the decertification date of Plant Branch Units 3 and 4. The decertification and retirement of Plant Kraft Units 1 through 4 (316 MWs) was also approved and will be effective by April 16, 2016, based on a one-year extension of the MATS rule compliance date that was approved by the State of Georgia Environmental Protection Division on September 10, 2013 to allow for necessary transmission system reliability improvements.

Additionally, the Georgia PSC approved the Company's proposed MATS rule compliance plan for emissions controls necessary for the continued operation of Plants Bowen Units 1 through 4, Wansley Units 1 and 2, Scherer Units 1 through 3, and Hammond Units 1 through 4, the switch to natural gas as the primary fuel at Plant Yates Units 6 and 7 and SEGCO's Plant Gaston Units 1 through 4, as well as the fuel switch at Plant McIntosh Unit 1 to operate on Powder River Basin coal. See Note 1 to the financial statements under "Affiliate Transactions" for additional information regarding the fuel switch at SEGCO's generating units.

In the 2013 ARP, the Georgia PSC approved the amortization of the construction work in progress (CWIP) balances related to environmental projects that will not be completed at Plant Branch Units 1 through 4 and Plant Yates Units 6 and 7 over nine years beginning in January 2014 and the amortization of any remaining net book values of Plant Branch Unit 2 from October 2013 to December 2022, Plant Branch Unit 1 from May 2015 to December 2020, Plant Branch Unit 3 from May 2015 to December 2023, and Plant Branch Unit 4 from May 2015 to December 2024. The Georgia PSC deferred a decision regarding the appropriate recovery period for the costs associated with unusable materials and supplies remaining at the retiring plants to the Company's next base rate case, which the Company expects to file in 2016 (2016 Rate Case). In the 2013 IRP, the Georgia PSC also deferred decisions regarding the recovery of any fuel related costs that could be incurred in connection with the retirement units to be addressed in future fuel cases.

A request was filed with the Georgia PSC on January 10, 2014 to cancel the proposed biomass fuel conversion of Plant Mitchell Unit 3 (155 MWs) because it would not be cost effective for customers. The filing also notified the Georgia PSC of the Company’s plans to seek decertification later this year. Plant Mitchell Unit 3 will continue to operate as a coal unit until April 2015 when it will be required to cease operation or install additional environmental controls to comply with the MATS rule. In connection with the retirement decision, the Company reclassified the retail portion of the net carrying value of Plant Mitchell Unit 3 from plant in service, net of depreciation, to other utility plant, net.

The decertification of these units and fuel conversions are not expected to have a material impact on the Company's financial statements; however, the ultimate outcome depends on the Georgia PSC's order in the 2016 Rate Case and future fuel cases and cannot be determined at this time.

Renewables Development

On December 17, 2013, four PPAs totaling 50 MWs of utility scale solar generation under the Georgia Power Advanced Solar Initiative (GPASI) were approved by the Georgia PSC, with the Company as the purchaser. These contracts will begin in 2015 and end in 2034. The resulting purchases will be for energy only and recovered through the Company’s fuel cost recovery mechanism. Under the 2013 IRP, the Georgia PSC approved an additional 525 MWs of solar generation to be purchased by the Company. The 525 MWs will be divided into 425 MWs of utility scale projects and 100 MWs of distributed generation.

On November 4, 2013, the Company filed an application for the certification of two PPAs which were executed on April 22, 2013 for the purchase of energy from two wind farms in Oklahoma with capacity totaling 250 MWs that will begin in 2016 and end in 2035.

During 2013, the Company executed four PPAs to purchase a total of 169 MWs of biomass capacity and energy from four facilities in Georgia that will begin in 2015 and end in 2035. On May 21, 2013, the Georgia PSC approved two of the biomass PPAs and the remaining two were approved on December 17, 2013. The four biomass PPAs are contingent upon the counterparty meeting specified contract dates for posting collateral and commercial operation. The ultimate outcome of this matter cannot be determined at this time.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved reductions in the Company's total annual billings of approximately $43 million effective June 1, 2011, $567 million effective June 1, 2012, and $122 million effective January 1, 2013. The 2013 reduction was due to the Georgia PSC authorizing an Interim Fuel Rider, which is set to expire June 1, 2014. The Company continues to be allowed to adjust its fuel cost recovery rates prior to the next fuel case if the under or over recovered fuel balance exceeds $200 million. The Company's fuel cost recovery includes costs associated with a natural gas hedging program as revised and approved by the Georgia PSC on February 7, 2013. See FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" herein and Note 11 to the financial statements under "Energy-Related Derivatives" for additional information. On February 18, 2014, the Georgia PSC approved the deferral of the Company's next fuel case, which is now expected to be filed by March 1, 2015.

The Company's over recovered fuel balance totaled approximately $58 million and $230 million at December 31, 2013 and December 31, 2012, respectively, and is included in current liabilities and other deferred credits and liabilities.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on the Company's revenues or net income, but will affect cash flow. See Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Cost Recovery" for additional information.

Storm Damage Recovery

The Company defers and recovers certain costs related to damages from major storms as mandated by the Georgia PSC. As of December 31, 2013, the balance in the regulatory asset related to storm damage was $37 million. As a result of this regulatory treatment, the costs related to storms are generally not expected to have a material impact on the Company's financial statements. See Note 1 to the financial statements under "Storm Damage Recovery" for additional information.

Nuclear Construction

In 2008, the Company, acting for itself and as agent for Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia (Dalton), acting by and through its Board of Water, Light, and Sinking Fund Commissioners (collectively, Owners), entered into an agreement with a consortium consisting of Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc. (collectively, Contractor), pursuant to which the Contractor agreed to design, engineer, procure, construct, and test two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities at Plant Vogtle (Vogtle 3 and 4 Agreement). Under the terms of the Vogtle 3 and 4 Agreement, the Owners agreed to pay a purchase price that is subject to certain price escalations and adjustments, including fixed escalation amounts and index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. Each Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Contractor under the Vogtle 3 and 4 Agreement. The Company's proportionate share is 45.7%. The Vogtle 3 and 4 Agreement provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees. The Contractor's liability to the Owners for schedule and performance liquidated damages and warranty claims is subject to a cap.

Certain payment obligations of Westinghouse and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and The Shaw Group, Inc., respectively. In the event of certain credit rating downgrades of any Owner, such Owner will be required to provide a letter of credit or other credit enhancement. The Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Owners will be required to pay certain termination costs. The Contractor may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including certain Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Owners, Owner insolvency, and certain other events.

In 2009, the U.S. Nuclear Regulatory Commission (NRC) issued an Early Site Permit and Limited Work Authorization which allowed limited work to begin on Plant Vogtle Units 3 and 4. The NRC certified the Westinghouse Design Control Document, as amended (DCD), for the AP1000 nuclear reactor design, effective December 30, 2011, and issued combined construction and operating licenses (COLs) in February 2012. Receipt of the COLs allowed full construction to begin. There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, at the federal and state level, and additional challenges are expected as construction proceeds.

In 2009, the Georgia PSC approved inclusion of the Plant Vogtle Units 3 and 4 related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows the Company to recover financing costs for nuclear construction projects certified by the Georgia PSC. Financing costs are recovered on all applicable certified costs through annual adjustments to the NCCR tariff by including the related CWIP accounts in rate base during the construction period. The Georgia PSC approved increases to the NCCR tariff of approximately $223 million, $35 million, $50 million, and $60 million, effective January 1, 2011, 2012, 2013, and 2014, respectively. Through the NCCR tariff, the Company is collecting and amortizing to earnings approximately $91 million of financing costs, capitalized in 2009 and 2010, over the five-year period ending December 31, 2015, in addition to the ongoing financing costs. At December 31, 2013, approximately $37 million of these 2009 and 2010 costs remained unamortized in CWIP.

The Company is required to file semi-annual Vogtle Construction Monitoring (VCM) reports with the Georgia PSC by February 28 and August 31 each year. If the projected certified construction capital costs to be borne by the Company increase by 5% or the projected in-service dates are significantly extended, the Company is required to seek an amendment to the Plant Vogtle Units 3 and 4 certificate from the Georgia PSC. Accordingly, the Company's eighth VCM report requested an amendment to the certificate to increase the estimated in-service capital cost of Plant Vogtle Units 3 and 4 from $4.4 billion to $4.8 billion and to extend the estimated in-service dates to the fourth quarter 2017 and the fourth quarter 2018 for Plant Vogtle Units 3 and 4, respectively.

On September 3, 2013, the Georgia PSC approved a stipulation entered into by the Company and the Georgia PSC staff to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate, until the commercial operation date of Plant Vogtle Unit 3, or earlier if deemed appropriate by the Georgia PSC and the Company. In accordance with the Georgia Integrated Resource Planning Act, any costs incurred by the Company in excess of the certified amount will not be included in rate base, unless shown to be reasonable and prudent. In addition, financing costs on any excess construction-related costs potentially would be subject to recovery through AFUDC instead of the NCCR tariff. As required by the stipulation, the Company filed an abbreviated status update with the Georgia PSC on September 3, 2013, which reflected approximately $2.4 billion of total construction capital costs incurred through June 30, 2013. On October 15, 2013, the Georgia PSC voted to approve the Company's eighth VCM report, reflecting construction capital costs incurred, which through December 31, 2012 totaled approximately $2.2 billion. Also in accordance with the stipulation, the Company will file with the Georgia PSC on February 28, 2014 a combined ninth and tenth VCM report covering the period from January 1 through December 31, 2013 (Ninth/Tenth VCM report), which will request approval for an additional $0.4 billion of construction capital costs. The Ninth/Tenth VCM report will reflect estimated in-service construction capital costs of $4.8 billion and associated financing costs during the construction period, which are estimated to total approximately $2.0 billion. The Company expects to resume filing semi-annual VCM reports in August 2014.

In July 2012, the Owners and the Contractor began negotiations regarding the costs associated with design changes to the DCD and the delays in the timing of approval of the DCD and issuance of the COLs, including the assertion by the Contractor that the Owners are responsible for these costs under the terms of the Vogtle 3 and 4 Agreement. The portion of the additional costs claimed by the Contractor that would be attributable to the Company (based on the Company's ownership interest) with respect to these issues is approximately $425 million (in 2008 dollars). The Contractor also has asserted it is entitled to further schedule extensions. The Company has not agreed with either the proposed cost or schedule adjustments or that the Owners have any responsibility for costs related to these issues. In November 2012, the Company and the other Owners filed suit against the Contractor in the U.S. District Court for the Southern District of Georgia seeking a declaratory judgment that the Owners are not responsible for these costs. Also in November 2012, the Contractor filed suit against the Company and the other Owners in the U.S. District Court for the District of Columbia alleging the Owners are responsible for these costs. On August 30, 2013, the U.S. District Court for the District of Columbia dismissed the Contractor's suit, ruling that the proper venue is the U.S. District Court for the Southern District of Georgia. The Contractor appealed the decision to the U.S. Court of Appeals for the District of Columbia Circuit on September 27, 2013. While litigation has commenced and the Company intends to vigorously defend its positions, the Company also expects negotiations with the Contractor to continue with respect to cost and schedule during which negotiations the parties may reach a mutually acceptable compromise of their positions.

Processes are in place that are designed to assure compliance with the requirements specified in the DCD and the COLs, including inspections by Southern Nuclear and the NRC that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the NRC. Various design and other licensing-based compliance issues are expected to arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs either to the Owners, the Contractor, or both.

As construction continues, the risk remains that additional challenges in the fabrication, assembly, delivery, and installation of structural modules, delays in the receipt of the remaining permits necessary for the operation of Plant Vogtle Units 3 and 4, or other issues could arise and may further impact project schedule and cost. Additional claims by the Contractor or the Company (on behalf of the Owners) are also likely to arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the Vogtle 3 and 4 Agreement, but also may be resolved through litigation.

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

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 $150 million in 2013 and is expected to have a positive impact between $40 million and $50 million on the cash flows of the Company in 2014.

Other Matters

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 and cannot be determined at this time; however, management does not currently anticipate that the compliance costs associated with these orders would have a material impact on the Company's financial statements.

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 April 4, 2013, an explosion occurred at Plant Bowen Unit 2 that resulted in substantial damage to the Plant Bowen Unit 2 generator, the Plant Bowen Units 1 and 2 control room and surrounding areas, and Plant Bowen's switchyard. Plant Bowen Unit 1 (approximately 700 MWs) was returned to service on August 4, 2013 and Plant Bowen Unit 2 (approximately 700 MWs) was returned to service on December 20, 2013. The Company expects that any material repair costs related to the damage will be covered by property insurance.

On November 19, 2013, the U.S. District Court for the District of Columbia ordered the U.S. Department of Energy (DOE) to cease collecting spent fuel depositary 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 $15 million annually based on its ownership interest. 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 Georgia PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation, 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 an $8 million or less change in total annual benefit expense and a $121 million or less change in projected obligations.

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 meet projected long-term demand requirements, 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 build new generation facilities, including Plant Vogtle Units 3 and 4, 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 issuances and capital contributions from Southern Company. 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 in 2013. The Company funded approximately $2 million to its nuclear decommissioning trust funds in 2013. See "Contractual Obligations" herein for additional information.

Net cash provided from operating activities totaled $2.8 billion in 2013, an increase of $471 million from 2012, primarily due to higher retail operating revenues, lower fuel inventory additions, and settlement of affiliated payables related to pension funding in 2012, partially offset by fuel cost recovery. Net cash provided from operating activities totaled $2.3 billion in 2012, a decrease of $337 million from 2011, primarily due to higher fuel inventory additions in 2012 and lower deferred taxes due to the effect of bonus depreciation in 2011, partially offset by higher recovery of retail fuel costs.

Net cash used for investing activities totaled $1.9 billion, $2.0 billion, and $1.8 billion in 2013, 2012, and 2011, respectively, due to gross property additions primarily related to installation of equipment to comply with environmental standards; construction of generation, transmission, and distribution facilities; and purchase of nuclear fuel. The majority of funds needed for gross property additions for the last several years has been provided from operating activities, capital contributions from Southern Company, and the issuance of debt.

Net cash used for financing activities totaled $891 million, $290 million, and $836 million for 2013, 2012, and 2011, respectively. The increase in cash used in 2013 compared to 2012 was primarily due to lower net issuances of long-term debt in 2013, partially offset by an increase in net short-term borrowings. The decrease in cash used in 2012 compared to 2011 was primarily due to additional debt issuances in 2012 to support the ongoing construction program. See "Financing Activities" herein for additional information. 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 in 2013 include an increase of $959 million in total property, plant, and equipment, a decrease of $250 million in fossil fuel stock, and a decrease in other regulatory assets, deferred of $646 million related to pension and other postretirement benefits.

The Company's ratio of common equity to total capitalization, including short-term debt, was 49.1% in 2013 and 48.3% in 2012. See Note 6 to the financial statements for additional information.

Sources of Capital

Except as described below with respect to the DOE loan guarantees, the Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, short-term debt, security issuances, term loans, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approvals, prevailing market conditions, and other factors.

On February 20, 2014, the Company and the DOE entered into a loan guarantee agreement (Loan Guarantee Agreement), pursuant to which the DOE agreed to guarantee borrowings to be made by the Company under a multi-advance credit facility (FFB Credit Facility) among the Company, the DOE, and the Federal Financing Bank (FFB). The Company's reimbursement obligations to the DOE are secured by a first priority lien on (i) the Company's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 and (ii) the Company's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. Under the FFB Credit Facility, the Company may make term loan borrowings through the FFB. Proceeds of borrowings made under the FFB Credit Facility will be used to reimburse the Company for a portion of certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the Loan Guarantee Agreement (Eligible Project Costs). Aggregate borrowings under the FFB Credit Facility may not exceed the lesser of (i) 70% of Eligible Project Costs or (ii) approximately $3.46 billion. See Note 6 to the financial statements for additional information.

The issuance of long-term securities by the Company is subject to the approval of the Georgia PSC. In addition, the issuance of short-term debt securities by the Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, the Company files registration statements with the U.S. Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended. The amounts of securities authorized by the Georgia PSC and the FERC are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company in the Southern Company system.

The Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the Company's business. The Company has substantial cash flow from operating activities and access to the capital markets to meet liquidity needs. At December 31, 2013, the Company had approximately $30 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2013 were as follows:

Expires[(a)]			
2016	**2018**	**Total**	**Unused**
	(in millions)		
$150	$1,600	$1,750	$1,736

(a) No credit arrangements expire in 2014, 2015, or 2017.

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

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. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2013 was approximately $862 million. In addition, at December 31, 2013, the Company had $242 million of fixed rate pollution control revenue bonds that will be required to be remarketed within the next 12 months.

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.

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[(a)]			Short-term Debt During the Period [(b)]				
		Amount Outstanding	Weighted Average Interest Rate		Average Outstanding	Weighted Average Interest Rate		Maximum Amount Outstanding
		(in millions)			*(in millions)*			*(in millions)*
December 31, 2013:								
Commercial paper	$	**647**	**0.2%**	$	**166**	**0.2%**	$	**702**
Short-term bank debt		**400**	**0.9%**		**96**	**0.9%**		**400**
Total	$	**1,047**	**0.5%**	$	**262**	**0.5%**		
December 31, 2012:								
Commercial paper	$	—	—%	$	78	0.2%	$	517
Short-term bank debt		—	—%		116	1.2%		300
Total	$	—	—%	$	194	0.8%		
December 31, 2011:								
Commercial paper	$	313	0.2%	$	208	0.3%	$	681
Short-term bank debt		200	1.2%		9	1.2%		200
Total	$	513	0.5%	$	217	0.3%		

(a) Excludes notes payable related to other energy service contracts of $2 million in 2012 and 2011.
(b) 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.

Financing Activities

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.

Pollution Control Revenue Bonds

In March 2013, the Development Authority of Monroe County issued $17.5 million aggregate principal amount of Pollution Control Revenue Bonds (Georgia Power Company Plant Scherer Project), First Series 2013 due April 1, 2043 for the benefit of the Company. The proceeds were used to redeem, in April 2013, $17.5 million aggregate principal amount of Development Authority of Monroe County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Scherer Project), Second Series 1997.

In August 2013, the Development Authority of Bartow County issued $71.7 million aggregate principal amount of Pollution Control Revenue Bonds (Georgia Power Company Plant Bowen Project), First Series 2013 due August 1, 2043 for the benefit of the Company. The proceeds were used to redeem, in September 2013, $24.9 million and $46.8 million aggregate principal amount of Development Authority of Bartow County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Bowen Project), First Series 1996 and 1998, respectively.

In November 2013, the Development Authority of Burke County issued $104.6 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 2013 due November 1, 2053 for the benefit of the Company. The proceeds were used to redeem, in November 2013, $55 million and $49.6 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), Third Series 1994 and First Series 1997, respectively. Also in November 2013, the Company purchased and now holds $104.6 million aggregate principal amount of pollution control revenue bonds issued for its benefit in 2013. The Company may reoffer these bonds to the public at a later date.

Senior Notes

In January 2013, the Company's $300 million aggregate principal amount of Series 2011A Floating Rate Senior Notes was paid at maturity.

In March 2013, the Company issued $400 million aggregate principal amount of Series 2013A 4.30% Senior Notes due March 15, 2043. Also in March 2013, the Company issued $250 million aggregate principal amount of Series 2013B Floating Rate Senior Notes due March 15, 2016. The proceeds from these sales were used to repay at maturity $350 million aggregate principal amount of the Company's Series 2010A Floating Rate Senior Notes due March 15, 2013, to repay a portion of its outstanding short-term indebtedness, and for general corporate purposes, including the Company's continuous construction program.

In August 2013, the Company issued $200 million aggregate principal amount of Series 2013C Floating Rate Senior Notes due August 15, 2016. The proceeds were used to repay at maturity a portion of $100 million aggregate principal amount outstanding of the Company's Series Q 4.90% Senior Notes and a portion of $500 million aggregate principal amount outstanding of the Company's Series 2010D 1.30% Senior Notes, both due September 15, 2013.

In November 2013, the Company redeemed $100 million aggregate principal amount of its Series 2008C 8.20% Senior Notes due November 1, 2048. In November and December 2013, the Company’s $400 million aggregate principal amount of 2008D 6.00% Senior Notes and $25 million aggregate principal amount of Series E 4.90% Senior Notes, respectively, were paid at maturity.

Other

In March 2013, the Company entered into three 60-day floating rate bank loans bearing interest based on one-month London Interbank Offered Rate (LIBOR). Each of these short-term loans was for $100 million aggregate principal amount, and the proceeds were used for working capital and other general corporate purposes, including the Company's continuous construction program. These bank loans were repaid at maturity.

In November 2013, the Company entered into three four-month floating rate bank loans for an aggregate principal amount of $400 million, bearing interest based on one-month LIBOR. The proceeds of these short-term loans were used for working capital and other general corporate purposes, including the Company's continuous construction program. Subsequent to December 31, 2013, the Company repaid these bank term loans.

These bank loans have covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes the long-term debt payable to affiliated trusts and other hybrid securities. At December 31, 2013, the Company was in compliance with its debt limits.

In addition, these bank loans contain cross default provisions to other indebtedness (including guarantee obligations) that would be triggered if the Company defaulted on indebtedness above a specified threshold. The Company is currently in compliance with all such covenants.

DOE Loan Guarantee Borrowings

Subsequent to December 31, 2013, the Company made initial borrowings under the FFB Credit Facility in an aggregate principal amount of $1.0 billion. The interest rate applicable to $500 million of the initial advance under the FFB Credit Facility is 3.860% for an interest period that extends to February 20, 2044 (the final maturity date) and the interest rate applicable to the remaining $500 million is 3.488% for an interest period that extends to February 20, 2029 and will be reset from time to time thereafter through the final maturity date. The final maturity date for all advances under the FFB Credit Facility is February 20, 2044. The proceeds of the initial borrowings under the FFB Credit Facility were used to reimburse the Company for Eligible Project Costs relating to the construction of Plant Vogtle Units 3 and 4. The Company's reimbursement obligations to the DOE are secured by a first priority lien on (i) the Company's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 and (ii) the Company's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. Under the Loan Guarantee Agreement, Georgia Power is subject to customary events of default, as well as cross-defaults to other indebtedness and events of default relating to any failure to make payments under the Vogtle 3 and 4 Agreement or certain other agreements providing intellectual property rights for Plant Vogtle Units 3 and 4. The Loan Guarantee Agreement also includes events of default specific to the DOE loan guarantee program, including the failure of Georgia Power or Southern Nuclear to comply with requirements of law or DOE loan guarantee program requirements. See Note 6 to the financial statements for additional information.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, energy price risk management, and construction of new generation. The maximum potential collateral requirements under these contracts at December 31, 2013 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB- and/or Baa3	$ 88
Below BBB- and/or Baa3	1,318

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 Ratings Services, a division of the McGraw Hill Companies, Inc. revised the ratings outlook for Southern Company and the traditional operating companies, including the Company, from stable to negative.

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 may enter into derivatives designated as hedges. The weighted average interest rate on $1.3 billion of outstanding variable rate long-term debt at January 1, 2014 was 0.25%. 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 $13 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 fuel-hedging program implemented per the guidelines of the Georgia 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.

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:

	2013 Changes	2012 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (34)**	$ (82)
Contracts realized or settled:		
Swaps realized or settled	**9**	53
Options realized or settled	**20**	18
Current period changes[(a)]:		
Swaps	**1**	(9)
Options	**(12)**	(14)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (16)**	$ (34)

(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:

	2013	2012
	mmBtu* Volume	
	(in millions)	
Commodity – Natural gas swaps	**7**	12
Commodity – Natural gas options	**52**	93
Total hedge volume	**59**	105

*million British thermal units (mmBtu)

The weighted average swap contract cost above market prices was approximately $0.50 per mmBtu as of December 31, 2013 and $1.09 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. All natural gas hedge gains and losses are recovered through the Company's fuel cost recovery mechanism.

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, which previously had a 48-month time horizon. In February 2013, the Georgia PSC approved changes to the Company's hedging program requiring it to use options and hedges within a 24-month time horizon. Hedging gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery mechanism. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are 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:

	Fair Value Measurements December 31, 2013		
	Total	Maturity	
	Fair Value	Year 1	Years 2&3
		(in millions)	
Level 1	$ —	$ —	$ —
Level 2	(16)	(10)	(6)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$ (16)	$ (10)	$ (6)

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related and interest rate derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's Investors Service, Inc. and Standard & Poor's Ratings Services, a division of The McGraw Hill Companies, Inc., or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements.

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to be $2.5 billion for 2014, $2.4 billion for 2015, and $2.1 billion for 2016. Capital expenditures to comply with environmental statutes and regulations included in these estimated amounts are $543 million, $366 million, and $202 million for 2014, 2015, and 2016, respectively. These amounts include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements.

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 FERC rules and regulations; Georgia PSC approvals; changes in the expected environmental compliance program; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. See Note 3 to the financial statements under "Retail Regulatory Matters – Nuclear Construction" for additional information.

As a result of requirements by the NRC, the Company has established external trust funds for nuclear decommissioning costs. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning."

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the Georgia PSC and the FERC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 6, 7, and 11 to the financial statements for additional information.

Contractual Obligations

	2014	2015-2016	2017-2018	After 2018	Total
			(in millions)		
Long-term debt[a] —					
Principal	$ —	$ 1,754	$ 720	$ 6,131	$ 8,605
Interest	298	577	510	4,280	5,665
Preferred and preference stock dividends[b]	17	35	35	—	87
Financial derivative obligations[c]	13	8	—	—	21
Operating leases[d]	26	33	15	11	85
Capital leases[d]	5	12	14	14	45
Purchase commitments —					
Capital[e]	2,290	4,052	—	—	6,342
Fuel[f]	1,713	2,486	1,535	5,373	11,107
Purchased power[g]	242	712	710	4,080	5,744
Other[h]	89	129	176	277	671
Trusts —					
Nuclear decommissioning[i]	2	11	11	115	139
Pension and other postretirement benefit plans[j]	34	65	—	—	99
Total	$ 4,729	$ 9,874	$ 3,726	$ 20,281	$ 38,610

(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. Long-term debt excludes capital lease amounts (shown separately).

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

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

(d) 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 environmental regulations. These amounts 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" herein 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 PPA purchases from gas-fired, biomass, and wind-powered facilities. A total of $1.3 billion of biomass PPAs is contingent upon the counterparty meeting specified contract dates for posting collateral and commercial operation. See Note 3 to the financial statements under "Retail Regulatory Matters – Renewables Development" for additional information.

(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) Projections of nuclear decommissioning trust fund contributions are based on the 2010 ARP for 2014 and on the 2013 ARP thereafter. See Note 1 to the financial statements under "Nuclear Decommissioning" for additional information.

(j) The Company forecasts contributions to the pension and other postretirement benefit plans over a three-year period. The Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from the Company's corporate assets. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 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, plans and estimated costs for new generation resources, completion dates of construction projects, 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 the 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, which include the development and construction of facilities with designs that have not been finalized or previously constructed, including changes in labor costs and productivity factors, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay or non-performance under construction or other agreements, delays associated with start-up activities, including major equipment failure, system integration, and operations, and/or unforeseen engineering problems;
- ability to construct facilities in accordance with the requirements of permits and licenses and to satisfy any operational and environmental performance standards, including the requirements of tax credits and other incentives;
- 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 cases related to fuel and other cost recovery mechanisms;
- regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals and NRC actions;
- the inherent risks involved in operating and constructing 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, as well as potential impacts on benefits of the DOE loan guarantees;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

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

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

	2013	2012	2011
		(in millions)	
Operating Revenues:			
Retail revenues	**$ 7,620**	$ 7,362	$ 8,099
Wholesale revenues, non-affiliates	**281**	281	341
Wholesale revenues, affiliates	**20**	20	32
Other revenues	**353**	335	328
Total operating revenues	**8,274**	7,998	8,800
Operating Expenses:			
Fuel	**2,307**	2,051	2,789
Purchased power, non-affiliates	**224**	315	390
Purchased power, affiliates	**660**	666	713
Other operations and maintenance	**1,654**	1,644	1,777
Depreciation and amortization	**807**	745	715
Taxes other than income taxes	**382**	374	369
Total operating expenses	**6,034**	5,795	6,753
Operating Income	**2,240**	2,203	2,047
Other Income and (Expense):			
Allowance for equity funds used during construction	**30**	53	96
Interest expense, net of amounts capitalized	**(361)**	(366)	(343)
Other income (expense), net	**5**	(17)	(13)
Total other income and (expense)	**(326)**	(330)	(260)
Earnings Before Income Taxes	**1,914**	1,873	1,787
Income taxes	**723**	688	625
Net Income	**1,191**	1,185	1,162
Dividends on Preferred and Preference Stock	**17**	17	17
Net Income After Dividends on Preferred and Preference Stock	**$ 1,174**	$ 1,168	$ 1,145

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
Georgia Power Company 2013 Annual Report

	2013	2012	2011
		(in millions)	
Net Income	**$ 1,191**	$ 1,185	$ 1,162
Other comprehensive income (loss):			
Qualifying hedges:			
Reclassification adjustment for amounts included in net income, net of tax of $1, $1, and $2, respectively	**2**	2	2
Total other comprehensive income (loss)	**2**	2	2
Comprehensive Income	**$ 1,193**	$ 1,187	$ 1,164

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
Georgia Power Company 2013 Annual Report

	2013	2012	2011
		(in millions)	
Operating Activities:			
Net income	**$ 1,191**	$ 1,185	$ 1,162
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	**979**	912	867
Deferred income taxes	**476**	377	500
Allowance for equity funds used during construction	**(30)**	(53)	(96)
Retail fuel cost over recovery—long-term	**(123)**	123	—
Pension, postretirement, and other employee benefits	**59**	9	(29)
Other, net	**37**	(12)	(23)
Changes in certain current assets and liabilities —			
-Receivables	**(58)**	205	235
-Fossil fuel stock	**250**	(269)	(99)
-Prepaid income taxes	**(17)**	(7)	72
-Other current assets	**40**	(53)	(21)
-Accounts payable	**67**	(165)	44
-Accrued taxes	**(14)**	(76)	(36)
-Accrued compensation	**(37)**	(18)	7
-Retail fuel cost over-recovery—short-term	**(49)**	107	—
-Other current liabilities	**(5)**	30	49
Net cash provided from operating activities	**2,766**	2,295	2,632
Investing Activities:			
Property additions	**(1,743)**	(1,723)	(1,861)
Investment in restricted cash from pollution control bonds	**(89)**	(284)	—
Distribution of restricted cash from pollution control bonds	**89**	284	—
Nuclear decommissioning trust fund purchases	**(706)**	(852)	(1,845)
Nuclear decommissioning trust fund sales	**705**	850	1,841
Cost of removal, net of salvage	**(59)**	(82)	(42)
Change in construction payables, net of joint owner portion	**(67)**	(149)	123
Other investing activities	**(20)**	(17)	(7)
Net cash used for investing activities	**(1,890)**	(1,973)	(1,791)
Financing Activities:			
Increase (decrease) in notes payable, net	**1,047**	(513)	(61)
Proceeds —			
Capital contributions from parent company	**37**	42	214
Pollution control revenue bonds issuances and remarketings	**194**	284	604
Senior notes issuances	**850**	2,300	550
Other long-term debt issuances	**—**	—	250
Redemptions and repurchases —			
Pollution control revenue bonds	**(298)**	(284)	(339)
Senior notes	**(1,775)**	(850)	(427)
Other long-term debt	**—**	(250)	(303)
Long-term debt to affiliate trust	**—**	—	(206)
Payment of preferred and preference stock dividends	**(17)**	(17)	(17)
Payment of common stock dividends	**(907)**	(983)	(1,096)
Other financing activities	**(22)**	(19)	(5)
Net cash used for financing activities	**(891)**	(290)	(836)
Net Change in Cash and Cash Equivalents	**(15)**	32	5
Cash and Cash Equivalents at Beginning of Year	**45**	13	8
Cash and Cash Equivalents at End of Year	**$ 30**	$ 45	$ 13
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $14, $21 and $37 capitalized, respectively)	**$ 344**	$ 337	$ 346
Income taxes (net of refunds)	**298**	312	54
Noncash transactions - accrued property additions at year-end	**208**	261	391

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

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

Assets	2013	2012
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 30**	$ 45
Receivables —		
Customer accounts receivable	**512**	484
Unbilled revenues	**209**	217
Joint owner accounts receivable	**67**	51
Other accounts and notes receivable	**117**	68
Affiliated companies	**21**	23
Accumulated provision for uncollectible accounts	**(5)**	(6)
Fossil fuel stock, at average cost	**742**	992
Materials and supplies, at average cost	**409**	452
Vacation pay	**88**	85
Prepaid income taxes	**97**	164
Other regulatory assets, current	**66**	72
Other current assets	**54**	104
Total current assets	**2,407**	2,751
Property, Plant, and Equipment:		
In service	**30,132**	29,244
Less accumulated provision for depreciation	**10,970**	10,431
Plant in service, net of depreciation	**19,162**	18,813
Other utility plant, net	**240**	263
Nuclear fuel, at amortized cost	**523**	497
Construction work in progress	**3,500**	2,893
Total property, plant, and equipment	**23,425**	22,466
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**46**	45
Nuclear decommissioning trusts, at fair value	**751**	698
Miscellaneous property and investments	**44**	44
Total other property and investments	**841**	787
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**718**	733
Prepaid pension costs	**118**	—
Other regulatory assets, deferred	**1,152**	1,798
Other deferred charges and assets	**246**	268
Total deferred charges and other assets	**2,234**	2,799
Total Assets	**$ 28,907**	$ 28,803

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

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

Liabilities and Stockholder's Equity	**2013**	2012
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 5**	$ 1,680
Notes payable	**1,047**	2
Accounts payable —		
Affiliated	**417**	417
Other	**472**	436
Customer deposits	**246**	237
Accrued taxes —		
Accrued income taxes	**—**	6
Other accrued taxes	**321**	260
Accrued interest	**91**	100
Accrued vacation pay	**61**	61
Accrued compensation	**80**	113
Liabilities from risk management activities	**13**	30
Other regulatory liabilities, current	**17**	73
Over recovered regulatory clause revenues, current	**14**	107
Other current liabilities	**122**	146
Total current liabilities	**2,906**	3,668
Long-Term Debt (See accompanying statements)	**8,633**	7,994
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**5,200**	4,861
Deferred credits related to income taxes	**112**	115
Accumulated deferred investment tax credits	**203**	208
Employee benefit obligations	**542**	950
Asset retirement obligations	**1,210**	1,097
Other cost of removal obligations	**43**	63
Other deferred credits and liabilities	**201**	308
Total deferred credits and other liabilities	**7,511**	7,602
Total Liabilities	**19,050**	19,264
Preferred Stock (See accompanying statements)	**45**	45
Preference Stock (See accompanying statements)	**221**	221
Common Stockholder's Equity (See accompanying statements)	**9,591**	9,273
Total Liabilities and Stockholder's Equity	**$ 28,907**	$ 28,803
Commitments and Contingent Matters (See notes)		

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

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

	2013	2012	2013	2012
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable —				
Variable rates (0.58% to 0.63% at 1/1/13) due 2013	**$ —**	$ 650		
Variable rates (0.57% to 0.65% at 1/1/14) due 2016	**450**	—		
1.30% to 6.00% due 2013	**—**	1,025		
0.625% to 5.25% due 2015	**1,050**	1,050		
3.00% due 2016	**250**	250		
5.70% due 2017	**450**	450		
5.40% due 2018	**250**	250		
2.85% to 8.20% due 2019-2048	**4,475**	4,175		
Total long-term notes payable	**6,925**	7,850		
Other long-term debt —				
Pollution control revenue bonds:				
0.80% to 5.75% due 2022-2049	**818**	919		
Variable rate (0.06% at 1/1/14) due 2016	**4**	4		
Variable rate (0.04% at 1/1/14) due 2018	**20**	20		
Variable rates (0.04% to 0.11% at 1/1/14) due 2022-2052	**838**	841		
Total other long-term debt	**1,680**	1,784		
Capitalized lease obligations	**45**	50		
Unamortized debt discount	**(12)**	(10)		
Total long-term debt (annual interest requirement — $298 million)	**8,638**	9,674		
Less amount due within one year	**5**	1,680		
Long-term debt excluding amount due within one year	**8,633**	7,994	**46.7%**	45.6%
Preferred and Preference Stock:				
Non-cumulative preferred stock				
$25 par value — 6.125%				
Authorized: 50,000,000 shares				
Outstanding: 1,800,000 shares	**45**	45		
Non-cumulative preference stock				
$100 par value — 6.50%				
Authorized: 15,000,000 shares				
Outstanding: 2,250,000 shares	**221**	221		
Total preferred and preference stock (annual dividend requirement — $17 million)	**266**	266	**1.4**	1.5
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized: 20,000,000 shares				
Outstanding: 9,261,500 shares	**398**	398		
Paid-in capital	**5,633**	5,585		
Retained earnings	**3,565**	3,297		
Accumulated other comprehensive loss	**(5)**	(7)		
Total common stockholder's equity	**9,591**	9,273	**51.9**	52.9
Total Capitalization	**$ 18,490**	$ 17,533	**100.0%**	100.0%

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

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

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
			(in millions)			
Balance at December 31, 2010	9	$ 398	$ 5,291	$ 3,063	$ (11)	$ 8,741
Net income after dividends on preferred and preference stock	—	—	—	1,145	—	1,145
Capital contributions from parent company	—	—	231	—	—	231
Other comprehensive income (loss)	—	—	—	—	2	2
Cash dividends on common stock	—	—	—	(1,096)	—	(1,096)
Balance at December 31, 2011	9	398	5,522	3,112	(9)	9,023
Net income after dividends on preferred and preference stock	—	—	—	1,168	—	1,168
Capital contributions from parent company	—	—	63	—	—	63
Other comprehensive income (loss)	—	—	—	—	2	2
Cash dividends on common stock	—	—	—	(983)	—	(983)
Balance at December 31, 2012	**9**	**398**	**5,585**	**3,297**	**(7)**	**9,273**
Net income after dividends on preferred and preference stock	**—**	**—**	**—**	**1,174**	**—**	**1,174**
Capital contributions from parent company	**—**	**—**	**48**	**—**	**—**	**48**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**2**	**2**
Cash dividends on common stock	**—**	**—**	**—**	**(907)**	**—**	**(907)**
Other	**—**	**—**	**—**	**1**	**—**	**1**
Balance at December 31, 2013	**9**	**$ 398**	**$ 5,633**	**$ 3,565**	**$ (5)**	**$ 9,591**

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

Index to the Notes to Financial Statements

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Georgia Power Company (the Company) is a wholly-owned subsidiary of The Southern Company (Southern Company), which is the parent company of the Company and three other traditional operating companies, as well as Southern Power Company (Southern Power), Southern Company Services, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies – the Company, Alabama Power Company (Alabama Power), Gulf Power Company (Gulf Power), and Mississippi Power Company – are vertically integrated utilities providing electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets, 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 Hatch and Plant Vogtle.

The equity method is used for subsidiaries in which the Company has significant influence but does not control.

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

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations, construction management, and power pool transactions. Costs for these services amounted to $504 million in 2013, $540 million in 2012, and $550 million in 2011. 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, operations, and construction management. Costs for these services amounted to $555 million in 2013, $574 million in 2012, and $537 million in 2011.

The Company has entered into several power purchase agreements (PPA) with Southern Power for capacity and energy. Expenses associated with these PPAs were $136 million, $147 million, and $171 million in 2013, 2012, and 2011, respectively. Additionally, the Company had $15 million of prepaid capacity expenses included in deferred charges and other assets in the balance sheets at December 31, 2013 and 2012. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

The Company has a joint ownership agreement with Gulf Power under which Gulf Power owns a 25% portion of Plant Scherer Unit 3. Under this agreement, the Company operates Plant Scherer Unit 3 and Gulf Power reimburses the Company for its 25% proportionate share of the related non-fuel expenses, which were $10 million in 2013, $7 million in 2012, and $7 million in 2011. See Note 4 for additional information.

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2013, 2012, or 2011.

See Note 4 for information regarding the Company's ownership in and a PPA with Southern Electric Generating Company (SEGCO). SEGCO plans to add natural gas as the primary fuel source for its generating units in 2015. SEGCO has entered into a joint ownership agreement with Alabama Power, which owns and operates a generating unit adjacent to the SEGCO units, for the ownership of the gas pipeline. SEGCO will own 86% of the pipeline with the remaining 14% owned by Alabama Power.

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.

Regulatory Assets and Liabilities

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

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

	2013	2012	Note
	(in millions)		
Retiree benefit plans	**$ 691**	$ 1,331	(a, k)
Deferred income tax charges	**684**	695	(b)
Deferred income tax charges — Medicare subsidy	**38**	43	(c)
Loss on reacquired debt	**181**	190	(d)
Asset retirement obligations	**137**	131	(b, k)
Fuel-hedging (realized and unrealized) losses	**22**	49	(e)
Vacation pay	**88**	85	(f, k)
Building leases	**37**	40	(g)
Cancelled construction projects	**70**	65	(h)
Remaining net book value of retired units	**28**	—	(i)
Other regulatory assets	**86**	100	(c)
Other cost of removal obligations	**(58)**	(94)	(b)
Deferred income tax credits	**(112)**	(115)	(b)
State income tax credits	**—**	(36)	(j)
Other regulatory liabilities	**(6)**	(13)	(e)
Total regulatory assets (liabilities), net	**$ 1,886**	$ 2,471	

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

(a) Recovered and amortized over the average remaining service period which may range up to 14 years. See Note 2 for additional information.

(b) Asset retirement and other cost of removal obligations and deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 70 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities. At December 31, 2013, other cost of removal obligations included $43 million that will be amortized over the three-year period of January 2014 through December 2016 in accordance with the Company's Alternate Rate Plan for the years 2014 through 2016 (2013 ARP).

(c) Recorded and recovered or amortized as approved by the Georgia PSC over periods generally not exceeding nine years.

(d) Recovered over either the remaining life of the original issue or, if refinanced, over the remaining life of the new issue, which currently does not exceed 39 years.

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

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

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

(h) Costs associated with construction of environmental controls that will not be completed as a result of unit retirements and amortized over nine years in accordance with the 2013 ARP.

(i) Amortization period over original remaining life beginning October 2013 through December 2022 as approved by the Georgia PSC in the 2013 ARP.

(j) Additional tax benefits resulting from the Georgia state income tax credit settlement that were amortized over a 21-month period that began in April 2012 and ended in December 2013, in accordance with a Georgia PSC order. See Note 5 under "Current and Deferred Income Taxes" for additional information.

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

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off 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.

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, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between the actual recoverable costs and amounts billed in current regulated rates.

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

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense includes 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. 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.

Federal investment tax credits (ITCs) utilized are deferred and amortized to income as a credit to reduce depreciation over the average life of the related property. State ITCs are recognized in the period in which the credits are claimed on the state income tax return. A portion of the ITCs available to reduce income taxes payable was not utilized currently and will be carried forward and utilized in future years.

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 cost of equity and debt funds used during construction.

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

	2013	2012
	(in millions)	
Generation	**$ 14,872**	$ 14,567
Transmission	**4,859**	4,581
Distribution	**8,620**	8,373
General	**1,753**	1,695
Plant acquisition adjustment	**28**	28
Total plant in service	**$ 30,132**	$ 29,244

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 certain generating plant maintenance costs. As mandated by the Georgia PSC, the Company defers and amortizes nuclear refueling outage costs over the unit's operating cycle. The refueling cycles are 18 and 24 months for Plant Vogtle Units 1 and 2 and Plant Hatch Units 1 and 2, respectively. Also, in accordance with a Georgia PSC order, the Company deferred the costs of certain significant inspection costs for the combustion turbine units at Plant McIntosh and amortized such costs over 10 years, which approximated the expected maintenance cycle of the units. All inspection costs were fully amortized in 2013.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.0% in 2013, 2.9% in 2012, and 2.8% in 2011. Depreciation studies are conducted periodically to update the composite rates that are approved by the Georgia PSC and the FERC. Effective January 1, 2014, the Company's depreciation rates were revised by the Georgia PSC in connection with the 2013 ARP. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

In 2009, the Georgia PSC approved an accounting order allowing the Company to amortize a portion of its regulatory liability related to other cost of removal obligations. Under the terms of the Company's Alternate Rate Plan for the years 2011 through 2013 (2010 ARP), the Company amortized approximately $31 million annually of the remaining regulatory liability related to other cost of removal obligations over the three years ended December 31, 2013. Under the terms of the 2013 ARP, an additional $43 million will be amortized ratably over the three years ending December 31, 2016.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations are computed as the present value of the ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. The Company has received accounting guidance from the Georgia PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The asset retirement obligation liability relates to the decommissioning of the Company's nuclear facilities, which include the Company's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2, as well as various landfill sites, ash ponds, underground storage tanks, and asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities, including the disposal of polychlorinated biphenyls in certain transformers; leasehold improvements; equipment on customer property; and property associated with the Company's rail lines and natural gas pipelines. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is 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 the allowed removal costs in accordance with its regulatory treatment. Any difference between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability in the balance sheets as ordered by the Georgia PSC. See "Nuclear Decommissioning" herein for additional information on amounts included in rates.

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

	2013	2012
	(in millions)	
Balance at beginning of year	**$ 1,105**	$ 757
Liabilities incurred	**2**	24
Liabilities settled	**(13)**	(15)
Accretion	**55**	72
Cash flow revisions	**73**	267
Balance at end of year	**$ 1,222**	$ 1,105

The increase in cash flow revisions is related to updated estimates for ash ponds in connection with the retirement of certain coal-fired generating units and revisions to the nuclear decommissioning asset retirement obligations based on the latest decommissioning study.

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 Georgia PSC, as well as the Internal Revenue Service (IRS). The Funds are required to be held by one or more trustees with an individual net worth of at least $100 million. The FERC requires the Funds' managers to exercise the standard of care in investing that a "prudent investor" would use in the same circumstances. The FERC regulations also require 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 discussed 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.

The Funds participate in a securities lending program through the managers of the Funds. Under this program, the Funds' investment securities are loaned to institutional investors for a fee. Securities so loaned are fully collateralized by cash, letters of credit, and securities issued or guaranteed by the U.S. government, its agencies, and the instrumentalities. As of December 31, 2013 and 2012, approximately $32 million and $91 million, respectively, of the fair market value of the Funds' securities were on loan and pledged to creditors under the Funds' managers' securities lending program. The fair value of the collateral received was approximately $33 million and $93 million at December 31, 2013 and 2012, respectively, and can only be sold by the borrower upon the return of the loaned securities. The collateral received is treated as a non-cash item in the statements of cash flows.

At December 31, 2013, investment securities in the Funds totaled $751 million, consisting of equity securities of $330 million, debt securities of $397 million, and $24 million of other securities. At December 31, 2012, investment securities in the Funds totaled $698 million, consisting of equity securities of $280 million, debt securities of $408 million, and $10 million of other securities. These amounts include the investment securities pledged to creditors and collateral received, and exclude receivables related to investment income and pending investment sales, and payables related to pending investment purchases and the lending pool.

Sales of the securities held in the Funds resulted in cash proceeds of $705 million, $850 million, and $1.8 billion 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 $61 million, of which $34 million related to unrealized gains on 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 $67 million, of which $25 million related to unrealized gains on 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 $23 million, of which $9 million related to unrealized losses on 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.

The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed plans with the NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.

Site study cost is the estimate to decommission a specific facility as of the site study year. The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from these estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates. The estimated costs of decommissioning are based on the most current study performed in 2012. The site study costs and external trust funds for decommissioning as of December 31, 2013 based on the Company's ownership interests were as follows:

	Plant Hatch	Plant Vogtle Units 1 and 2
Decommissioning periods:		
Beginning year	2034	2047
Completion year	2068	2072
	(in millions)	
Site study costs:		
Radiated structures	$ 549	$ 453
Spent fuel management	131	115
Non-radiated structures	51	76
Total site study costs	$ 731	$ 644
External trust funds	$ 469	$ 277

For ratemaking purposes, the Company's decommissioning costs are based on the NRC generic estimate to decommission the radioactive portion of the facilities and the site study estimate for spent fuel management as of 2012. The Georgia PSC approved annual decommissioning costs for ratemaking of $2 million annually for Plant Hatch for 2011 through 2013. Under the 2013 ARP, the annual decommissioning cost through 2016 for ratemaking is $4 million and $2 million for Plant Hatch and Plant Vogtle Units 1 and 2, respectively. Significant assumptions used to determine the costs for ratemaking include an estimated inflation rate of 2.4% and an estimated trust earnings rate of 4.4%. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for nuclear decommissioning costs.

Allowance for Funds Used During Construction

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. For the years 2013, 2012, and 2011, the average AFUDC rates were 5.3%, 6.8%, and 7.5%, respectively, and AFUDC capitalized was $44 million, $75 million, and $134 million, respectively. AFUDC, net of income taxes, was 3.3%, 5.7%, and 10.4% of net income after dividends on preferred and preference stock for 2013, 2012, and 2011, respectively. See Note 3 under "Retail Regulatory Matters – Nuclear Construction" for additional information on the inclusion of construction costs related to the construction of two new nuclear generating units at Plant Vogtle (Plant Vogtle Units 3 and 4) in rate base effective January 1, 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.

Storm Damage Recovery

The Company defers and recovers certain costs related to damages from major storms as mandated by the Georgia PSC. Under the 2010 ARP, the Company accrued $18 million annually that was recoverable through base rates. At December 31, 2013, the Company's regulatory asset related to storm damage was $37 million, with approximately $30 million included in other regulatory assets, current and approximately $7 million included as other regulatory assets, deferred. Beginning January 1, 2014, the Company is accruing $30 million annually under the 2013 ARP. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for storm damage costs.

Environmental Remediation Recovery

The Company maintains a reserve for environmental remediation as mandated by the Georgia PSC. On December 17, 2013, the Georgia PSC approved the 2013 ARP including the recovery of approximately $2 million annually through the environmental compliance cost recovery (ECCR) tariff from 2014 through 2016. The Company recovered approximately $3 million annually through the ECCR tariff from 2011 through 2013 under the 2010 ARP. The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable and reduces the reserve as expenditures are incurred. Any difference between the liabilities accrued and cost recovered through rates is deferred as a regulatory asset or liability. The annual recovery amount is expected to be reviewed by the Georgia PSC and adjusted in future regulatory proceedings. As a result of this regulatory treatment, environmental remediation liabilities generally are not expected to have a material impact on the Company's financial statements. As of December 31, 2013, the balance of the environmental remediation liability was $18 million, with approximately $2 million included in other regulatory assets, current and approximately $9 million included as other regulatory assets, deferred. See Note 3 under "Environmental Matters – Environmental Remediation" 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, and oil, as well as 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 fuel cost recovery rates approved by the Georgia 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 Georgia PSC-approved fuel-hedging program. This results in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts are marked to market through current period income and are recorded on a net basis in the statements of income. See Note 11 for additional information.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to 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.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made 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 Georgia PSC and the FERC. For the year ending December 31, 2014, other postretirement trust contributions are expected to total approximately $13 million.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2010 for the 2011 plan year using discount rates for the pension plans and the other postretirement benefit plans of 5.52% and 5.40%, respectively, and an annual salary increase of 3.84%.

	2013	2012	2011
Discount rate:			
Pension plans	**5.02%**	4.27%	4.98%
Other postretirement benefit plans	**4.85**	4.04	4.87
Annual salary increase	**3.59**	3.59	3.84
Long-term return on plan assets:			
Pension plans	**8.20**	8.20	8.45
Other postretirement benefit plans	**6.74**	7.24	7.25

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:

	1 Percent Increase	**1 Percent Decrease**
	(in millions)	
Benefit obligation	$ 51	$ (43)
Service and interest costs	2	(2)

Pension Plans

The total accumulated benefit obligation for the pension plans was $2.9 billion at December 31, 2013 and $3.1 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
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 3,312**	$ 2,909
Service cost	**69**	60
Interest cost	**138**	141
Benefits paid	**(141)**	(136)
Actuarial (gain) loss	**(262)**	338
Balance at end of year	**3,116**	3,312
Change in plan assets		
Fair value of plan assets at beginning of year	**2,827**	2,575
Actual return on plan assets	**387**	377
Employer contributions	**12**	11
Benefits paid	**(141)**	(136)
Fair value of plan assets at end of year	**3,085**	2,827
Accrued liability	**$ (31)**	$ (485)

At December 31, 2013, the projected benefit obligations for the qualified and non-qualified pension plans were $3.0 billion and $148 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
	(in millions)	
Prepaid pension costs	**$ 118**	$ —
Other regulatory assets, deferred	**610**	1,132
Current liabilities, other	**(12)**	(11)
Employee benefit obligations	**(137)**	(474)

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**
		(in millions)	
Prior service cost	**$ 26**	$ 37	$ 10
Net (gain) loss	**584**	1,095	41
Regulatory assets	**$ 610**	$ 1,132	

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
	(in millions)	
Regulatory assets:		
Beginning balance	**$ 1,132**	$ 995
Net (gain) loss	**(438)**	182
Reclassification adjustments:		
Amortization of prior service costs	**(10)**	(12)
Amortization of net gain (loss)	**(74)**	(33)
Total reclassification adjustments	**(84)**	(45)
Total change	**(522)**	137
Ending balance	**$ 610**	$ 1,132

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

	2013	2012	2011
		(in millions)	
Service cost	**$ 69**	$ 60	$ 57
Interest cost	**138**	141	144
Expected return on plan assets	**(212)**	(221)	(234)
Recognized net loss	**74**	33	6
Net amortization	**10**	12	12
Net periodic pension cost (income)	**$ 79**	$ 25	$ (15)

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:

	Benefit Payments
	(in millions)
2014	$ 154
2015	161
2016	167
2017	175
2018	181
2019 to 2023	995

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:

	2013	2012
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$ 800	$ 774
Service cost	7	7
Interest cost	31	37
Benefits paid	(45)	(46)
Actuarial (gain) loss	(73)	25
Retiree drug subsidy	3	3
Balance at end of year	723	800
Change in plan assets		
Fair value of plan assets at beginning of year	382	365
Actual return on plan assets	56	43
Employer contributions	11	17
Benefits paid	(42)	(43)
Fair value of plan assets at end of year	407	382
Accrued liability	$ (316)	$ (418)

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:

	2013	2012
	(in millions)	
Other regulatory assets, deferred	$ 69	$ 187
Employee benefit obligations	(316)	(418)

Presented below are the amounts included in regulatory assets 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
		(in millions)	
Prior service cost	$ (4)	$ (4)	$ —
Net (gain) loss	73	186	2
Transition obligation	—	5	—
Regulatory assets	$ 69	$ 187	

The changes in the balance of regulatory assets 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
	(in millions)	
Regulatory assets:		
Beginning balance	**$ 187**	$ 186
Net (gain) loss	**(106)**	11
Reclassification adjustments:		
Amortization of transition obligation	**(4)**	(6)
Amortization of prior service costs	**—**	—
Amortization of net gain (loss)	**(8)**	(4)
Total reclassification adjustments	**(12)**	(10)
Total change	**(118)**	1
Ending balance	**$ 69**	$ 187

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

	2013	2012	2011
		(in millions)	
Service cost	**$ 7**	$ 7	$ 7
Interest cost	**31**	37	41
Expected return on plan assets	**(24)**	(29)	(30)
Net amortization	**12**	10	11
Net periodic postretirement benefit cost	**$ 26**	$ 25	$ 29

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

	Benefit Payments	**Subsidy Receipts**	**Total**
		(in millions)	
2014	$ 49	$ (4)	$ 45
2015	50	(4)	46
2016	53	(5)	48
2017	54	(5)	49
2018	58	(6)	52
2019 to 2023	287	(30)	257

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
Pension plan assets:			
Domestic equity	26%	**31%**	28%
International equity	25	**25**	24
Fixed income	23	**23**	27
Special situations	3	**1**	1
Real estate investments	14	**14**	13
Private equity	9	**6**	7
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	41%	**36%**	34%
International equity	21	**30**	27
Domestic fixed income	24	**21**	27
Global fixed income	8	**8**	7
Special situations	1	**—**	—
Real estate investments	3	**3**	3
Private equity	2	**2**	2
Total	100%	**100%**	100%

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns 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.
- ***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.

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.

	Fair Value Measurements Using			
As of December 31, 2013:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 506	$ 296	$ —	$ 802
International equity*	389	359	—	748
Fixed income:				
U.S. Treasury, government, and agency bonds	—	212	—	212
Mortgage- and asset-backed securities	—	55	—	55
Corporate bonds	—	346	—	346
Pooled funds	—	166	—	166
Cash equivalents and other	—	79	—	79
Real estate investments	92	—	353	445
Private equity	—	—	202	202
Total	$ 987	$ 1,513	$ 555	$ 3,055
Liabilities:				
Derivatives	—	(1)	—	(1)
Total	$ 987	$ 1,512	$ 555	$ 3,054

* 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 Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 413	$ 238	$ —	$ 651
International equity*	324	348	—	672
Fixed income:				
U.S. Treasury, government, and agency bonds	—	183	—	183
Mortgage- and asset-backed securities	—	45	—	45
Corporate bonds	—	312	1	313
Pooled funds	—	142	—	142
Cash equivalents and other	2	195	—	197
Real estate investments	92	—	299	391
Private equity	—	—	211	211
Total	$ 831	$ 1,463	$ 511	$ 2,805

* 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**
		(in millions)		
Beginning balance	**$ 299**	**$ 211**	$ 296	$ 220
Actual return on investments:				
Related to investments held at year end	**25**	**3**	2	—
Related to investments sold during the year	**10**	**17**	1	2
Total return on investments	**35**	**20**	3	2
Purchases, sales, and settlements	**19**	**(29)**	—	(11)
Ending balance	**$ 353**	**$ 202**	$ 299	$ 211

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.

	Fair Value Measurements Using			
As of December 31, 2013:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
	(in millions)			
Assets:				
Domestic equity*	$ 74	$ 25	$ —	$ 99
International equity*	12	57	—	69
Fixed income:				
U.S. Treasury, government, and agency bonds	—	7	—	7
Mortgage- and asset-backed securities	—	2	—	2
Corporate bonds	—	11	—	11
Pooled funds	—	34	—	34
Cash equivalents and other	—	6	—	6
Trust-owned life insurance	—	158	—	158
Real estate investments	3	—	11	14
Private equity	—	—	6	6
Total	$ 89	$ 300	$ 17	$ 406

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

	Fair Value Measurements Using			
As of December 31, 2012:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Domestic equity*	$ 65	$ 27	$ —	$ 92
International equity*	10	51	—	61
Fixed income:				
U.S. Treasury, government, and agency bonds	—	6	—	6
Mortgage- and asset-backed securities	—	1	—	1
Corporate bonds	—	10	—	10
Pooled funds	—	32	—	32
Cash equivalents and other	—	18	—	18
Trust-owned life insurance	—	142	—	142
Real estate investments	3	—	10	13
Private equity	—	—	7	7
Total	$ 78	$ 287	$ 17	$ 382

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

Changes in the fair value measurement of the Level 3 items in the other postretirement benefit plan assets valued using significant unobservable inputs for the years ended December 31, 2013 and 2012 were as follows:

	2013		2012	
	Real Estate Investments	**Private Equity**	**Real Estate Investments**	**Private Equity**
		(in millions)		
Beginning balance	**$ 10**	**$ 7**	$ 9	$ 7
Actual return on investments:				
Related to investments held at year end	**1**	**—**	1	—
Related to investments sold during the year	**—**	**—**	—	—
Total return on investments	**1**	**—**	1	—
Purchases, sales, and settlements	**—**	**(1)**	—	—
Ending balance	**$ 11**	**$ 6**	$ 10	$ 7

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 $24 million, $24 million, and $24 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 provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by Gulf 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 related to a unit co-owned by Gulf Power) has been administratively closed in the U.S. District Court for the Northern District of Georgia since 2001.

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 Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. See Note 1 under "Environmental Remediation Recovery" for additional information.

The Company has been designated or identified as a potentially responsible party (PRP) at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), including a site in Brunswick, Georgia on the CERCLA National Priorities List (NPL). The parties have completed the removal of wastes from the Brunswick site as ordered by the EPA. Additional cleanup and claims for recovery of natural resource damages at this site or for the assessment and potential cleanup of other sites are anticipated.

The Company and numerous other entities have been designated by the EPA as PRPs at the Ward Transformer Superfund site located in Raleigh, North Carolina. In 2011, the EPA issued a Unilateral Administrative Order (UAO) to the Company and 22 other parties, ordering specific remedial action of certain areas at the site. Later in 2011, the Company filed a response with the EPA stating it has sufficient cause to believe it is not a liable party under CERCLA. The EPA notified the Company in 2011 that it is considering enforcement options against the Company and other non-complying UAO recipients. If the EPA pursues enforcement actions and the court determines that a respondent failed to comply with the UAO without sufficient cause, the EPA may also seek civil penalties of up to $37,500 per day for the violation and punitive damages of up to three times the costs incurred by the EPA as a result of the party's failure to comply with the UAO.

In addition to the EPA's action at this site, the Company, along with many other parties, was sued in a private action by several existing PRPs for cost recovery related to the removal action. On February 1, 2013, the U.S. District Court for the Eastern District of North Carolina Western Division granted the Company's summary judgment motion, ruling that the Company has no liability in the private action. On May 10, 2013, the plaintiffs appealed the U.S. District Court for the Eastern District of North Carolina Western Division's order to the U.S. Court of Appeals for the Fourth Circuit.

The ultimate outcome of these matters will depend upon the success of defenses asserted, the ultimate number of PRPs participating in the cleanup, and numerous other factors and cannot be determined at this time; however, as a result of the regulatory recovery mechanisms described in Note 1 under "Environmental Remediation Recovery," these matters are not expected to have a material impact on the Company's financial statements.

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 contracts with the Company that require the DOE to dispose of spent nuclear fuel and high level radioactive waste generated at Plant Hatch and Plant Vogtle Units 1 and 2. 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 its first lawsuit, the Company recovered approximately $27 million, based on its ownership interests, representing the vast majority of the Company's direct costs of the expansion of spent nuclear fuel storage facilities at Plant Hatch and Plant Vogtle Units 1 and 2 from 1998 through 2004. The proceeds were received in July 2012 and credited to the Company accounts where the original costs were charged and were used to reduce rate base, fuel, and 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 Hatch and Plant Vogtle Units 1 and 2. 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 as a significant portion of any damage amounts collected from the government is expected to be credited to the Company accounts where the original costs were charged and used to reduce rate base, fuel, and cost of service for the benefit of customers.

An on-site dry storage facility at Plant Vogtle Units 1 and 2 began operation in October 2013. At Plant Hatch, an on-site dry spent fuel storage facility is also operational. Facilities at both plants can be expanded to accommodate spent fuel through the expected life of each plant.

Retail Regulatory Matters

Rate Plans

In 2010, the Georgia PSC approved the 2010 ARP, which resulted in base rate increases of approximately $562 million, $17 million, $125 million, and $74 million effective January 1, 2011, January 1, 2012, April 1, 2012, and January 1, 2013, respectively.

On December 17, 2013, the Georgia PSC voted to approve the 2013 ARP. The 2013 ARP reflects the settlement agreement among the Company, the Georgia PSC's Public Interest Advocacy Staff, and 11 of the 13 intervenors, which was filed with the Georgia PSC on November 18, 2013.

On January 1, 2014, in accordance with the 2013 ARP, the Company increased its tariffs as follows: (1) traditional base tariff rates by approximately $80 million; (2) ECCR tariff by an additional $25 million; (3) Demand-Side Management (DSM) tariffs by an additional $1 million; and (4) Municipal Franchise Fee (MFF) tariff by an additional $4 million, for a total increase in base revenues of approximately $110 million.

Under the 2013 ARP, the following additional rate adjustments will be made to the Company's tariffs in 2015 and 2016 based on annual compliance filings to be made at least 90 days prior to the effective date of the tariffs:

- Effective January 1, 2015 and 2016, the traditional base tariff rates will increase by an estimated $101 million and $36 million, respectively, to recover additional generation capacity-related costs;
- Effective January 1, 2015 and 2016, the ECCR tariff will increase by an estimated $76 million and $131 million, respectively, to recover additional environmental compliance costs;
- Effective January 1, 2015, the DSM tariffs will increase by an estimated $6 million and decrease by an estimated $1 million effective January 1, 2016; and
- The MFF tariff will increase consistent with these adjustments.

The Company currently estimates these adjustments will result in base revenue increases of approximately $187 million in 2015 and $170 million in 2016. The estimated traditional base tariff rate increases for 2015 and 2016 do not include additional Qualifying Facility (QF) PPA expenses; however, compliance filings will include QF PPA expenses for those facilities that are projected to provide capacity to the Company during the following year.

Under the 2013 ARP, the Company's retail return on common equity (ROE) is set at 10.95%, and earnings are evaluated against a retail ROE range of 10.00% to 12.00%. Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by the Company. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. However, if at any time during the term of the 2013 ARP, the Company projects that its retail earnings will be below 10.00% for any calendar year, it may petition the Georgia PSC for implementation of the Interim Cost Recovery (ICR) tariff that would be used to adjust the Company's earnings back to a 10.00% retail ROE. The Georgia PSC would have 90 days to rule on the Company's request. The ICR tariff will expire at the earlier of January 1, 2017 or the end of the calendar year in which the

ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR tariff, the Company may file a full rate case.

Except as provided above, the Company will not file for a general base rate increase while the 2013 ARP is in effect. The Company is required to file a general rate case by July 1, 2016, in response to which the Georgia PSC would be expected to determine whether the 2013 ARP should be continued, modified, or discontinued.

Integrated Resource Plans

On January 31, 2013, the Company filed its triennial Integrated Resource Plan (2013 IRP). The filing included the Company's request to decertify 16 coal- and oil-fired units totaling 2,093 megawatts (MWs). Several factors, including the cost to comply with existing and future environmental regulations, recent and forecasted economic conditions, and lower natural gas prices, contributed to the decision to close these units.

On April 17, 2013, the Georgia PSC approved the decertification of Plant Bowen Unit 6 (32 MWs), which was retired on April 25, 2013. On September 30, 2013, Plant Branch Unit 2 (319 MWs) was retired as approved by the Georgia PSC in the 2011 Integrated Resource Plan Update (2011 IRP Update) in order to comply with the State of Georgia's Multi-Pollutant Rule.

On July 11, 2013, the Georgia PSC approved the Company's request to decertify and retire Plant Boulevard Units 2 and 3 (28 MWs) effective July 17, 2013. Plant Branch Units 3 and 4 (1,016 MWs), Plant Yates Units 1 through 5 (579 MWs), and Plant McManus Units 1 and 2 (122 MWs) will be decertified and retired by April 16, 2015, the compliance date of the Mercury and Air Toxics Standards (MATS) rule. The decertification date of Plant Branch Unit 1 was extended from December 31, 2013 as specified in the final order in the 2011 IRP Update to coincide with the decertification date of Plant Branch Units 3 and 4. The decertification and retirement of Plant Kraft Units 1 through 4 (316 MWs) was also approved and will be effective by April 16, 2016, based on a one-year extension of the MATS rule compliance date that was approved by the State of Georgia Environmental Protection Division on September 10, 2013 to allow for necessary transmission system reliability improvements.

Additionally, the Georgia PSC approved the Company's proposed MATS rule compliance plan for emissions controls necessary for the continued operation of Plants Bowen Units 1 through 4, Wansley Units 1 and 2, Scherer Units 1 through 3, and Hammond Units 1 through 4, the switch to natural gas as the primary fuel at Plant Yates Units 6 and 7 and SEGCO's Plant Gaston Units 1 through 4, as well as the fuel switch at Plant McIntosh Unit 1 to operate on Powder River Basin coal. See Note 1 under "Affiliate Transactions" herein for additional information regarding the fuel switch at SEGCO's generating units.

In the 2013 ARP, the Georgia PSC approved the amortization of the construction work in progress (CWIP) balances related to environmental projects that will not be completed at Plant Branch Units 1 through 4 and Plant Yates Units 6 and 7 over nine years beginning in January 2014 and the amortization of any remaining net book values of Plant Branch Unit 2 from October 2013 to December 2022, Plant Branch Unit 1 from May 2015 to December 2020, Plant Branch Unit 3 from May 2015 to December 2023, and Plant Branch Unit 4 from May 2015 to December 2024. The Georgia PSC deferred a decision regarding the appropriate recovery period for the costs associated with unusable materials and supplies remaining at the retiring plants to the Company's next base rate case, which the Company expects to file in 2016 (2016 Rate Case). In the 2013 IRP, the Georgia PSC also deferred decisions regarding the recovery of any fuel related costs that could be incurred in connection with the retirement units to be addressed in future fuel cases.

A request was filed with the Georgia PSC on January 10, 2014 to cancel the proposed biomass fuel conversion of Plant Mitchell Unit 3 (155 MWs) because it would not be cost effective for customers. The filing also notified the Georgia PSC of the Company’s plans to seek decertification later this year. Plant Mitchell Unit 3 will continue to operate as a coal unit until April 2015 when it will be required to cease operation or install additional environmental controls to comply with the MATS rule. In connection with the retirement decision, the Company reclassified the retail portion of the net carrying value of Plant Mitchell Unit 3 from plant in service, net of depreciation, to other utility plant, net.

The decertification of these units and fuel conversions are not expected to have a material impact on the Company's financial statements; however, the ultimate outcome depends on the Georgia PSC's order in the 2016 Rate Case and future fuel cases and cannot be determined at this time.

Renewables Development

On December 17, 2013, four PPAs totaling 50 MWs of utility scale solar generation under the Georgia Power Advanced Solar Initiative (GPASI) were approved by the Georgia PSC, with the Company as the purchaser. These contracts will begin in 2015 and end in 2034. The resulting purchases will be for energy only and recovered through the Company’s fuel cost recovery mechanism. Under the 2013 IRP, the Georgia PSC approved an additional 525 MWs of solar generation to be purchased by the Company. The 525 MWs will be divided into 425 MWs of utility scale projects and 100 MWs of distributed generation.

On November 4, 2013, the Company filed an application for the certification of two PPAs which were executed on April 22, 2013 for the purchase of energy from two wind farms in Oklahoma with capacity totaling 250 MWs that will begin in 2016 and end in 2035.

During 2013, the Company executed four PPAs to purchase a total of 169 MWs of biomass capacity and energy from four facilities in Georgia that will begin in 2015 and end in 2035. On May 21, 2013, the Georgia PSC approved two of the biomass PPAs and the remaining two were approved on December 17, 2013. The four biomass PPAs are contingent upon the counterparty meeting specified contract dates for posting collateral and commercial operation. The ultimate outcome of this matter cannot be determined at this time.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved reductions in the Company's total annual billings of approximately $43 million effective June 1, 2011, $567 million effective June 1, 2012, and $122 million effective January 1, 2013. The 2013 reduction was due to the Georgia PSC authorizing an Interim Fuel Rider, which is set to expire June 1, 2014. The Company continues to be allowed to adjust its fuel cost recovery rates prior to the next fuel case if the under or over recovered fuel balance exceeds $200 million. The Company's fuel cost recovery includes costs associated with a natural gas hedging program as revised and approved by the Georgia PSC on February 7, 2013, requiring it to use options and hedges within a 24-month time horizon. See Note 11 under "Energy-Related Derivatives" for additional information. On February 18, 2014, the Georgia PSC approved the deferral of the Company's next fuel case, which is now expected to be filed by March 1, 2015.

The Company's over recovered fuel balance totaled approximately $58 million and $230 million at December 31, 2013 and 2012, respectively, and is included in current liabilities and other deferred credits and liabilities.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on the Company's revenues or net income, but will affect cash flow.

Nuclear Construction

In 2008, the Company, acting for itself and as agent for Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia (Dalton), acting by and through its Board of Water, Light, and Sinking Fund Commissioners (collectively, Owners), entered into an agreement with a consortium consisting of Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc. (collectively, Contractor), pursuant to which the Contractor agreed to design, engineer, procure, construct, and test two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities at Plant Vogtle (Vogtle 3 and 4 Agreement). Under the terms of the Vogtle 3 and 4 Agreement, the Owners agreed to pay a purchase price that is subject to certain price escalations and adjustments, including fixed escalation amounts and index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. Each Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Contractor under the Vogtle 3 and 4 Agreement. The Company's proportionate share is 45.7%. The Vogtle 3 and 4 Agreement provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees. The Contractor's liability to the Owners for schedule and performance liquidated damages and warranty claims is subject to a cap.

Certain payment obligations of Westinghouse and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and The Shaw Group, Inc., respectively. In the event of certain credit rating downgrades of any Owner, such Owner will be required to provide a letter of credit or other credit enhancement. The Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Owners will be required to pay certain termination costs. The Contractor may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including certain Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Owners, Owner insolvency, and certain other events.

In 2009, the NRC issued an Early Site Permit and Limited Work Authorization which allowed limited work to begin on Plant Vogtle Units 3 and 4. The NRC certified the Westinghouse Design Control Document, as amended (DCD), for the AP1000 nuclear reactor design, effective December 30, 2011, and issued combined construction and operating licenses (COLs) in February 2012. Receipt of the COLs allowed full construction to begin. There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, at the federal and state level, and additional challenges are expected as construction proceeds.

In 2009, the Georgia PSC approved inclusion of the Plant Vogtle Units 3 and 4 related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows the Company to recover financing costs for nuclear construction projects certified by the Georgia PSC. Financing costs are recovered on all applicable certified costs through annual adjustments to the Nuclear Construction Cost Recovery (NCCR) tariff by including the related CWIP accounts in rate base during the construction period. The Georgia PSC approved increases to the NCCR tariff of approximately $223 million, $35 million, $50 million, and $60 million, effective January 1, 2011, 2012, 2013, and 2014, respectively. Through the NCCR tariff, the Company is collecting and amortizing to earnings approximately $91 million of financing costs, capitalized in 2009 and 2010, over the five-year period ending December 31, 2015, in addition to the ongoing financing costs. At December 31, 2013, approximately $37 million of these 2009 and 2010 costs remained unamortized in CWIP.

The Company is required to file semi-annual Vogtle Construction Monitoring (VCM) reports with the Georgia PSC by February 28 and August 31 each year. If the projected certified construction capital costs to be borne by the Company increase by 5% or the projected in-service dates are significantly extended, the Company is required to seek an amendment to the Plant Vogtle Units 3 and 4 certificate from the Georgia PSC. Accordingly, the Company's eighth VCM report requested an amendment to the certificate to increase the estimated in-service capital cost of Plant Vogtle Units 3 and 4 from $4.4 billion to $4.8 billion and to extend the estimated in-service dates to the fourth quarter 2017 and the fourth quarter 2018 for Plant Vogtle Units 3 and 4, respectively.

On September 3, 2013, the Georgia PSC approved a stipulation entered into by the Company and the Georgia PSC staff to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate, until the commercial operation date of Plant Vogtle Unit 3, or earlier if deemed appropriate by the Georgia PSC and the Company. In accordance with the Georgia Integrated Resource Planning Act, any costs incurred by the Company in excess of the certified amount will not be included in rate base, unless shown to be reasonable and prudent. In addition, financing costs on any excess construction-related costs potentially would be subject to recovery through AFUDC instead of the NCCR tariff. As required by the stipulation, the Company filed an abbreviated status update with the Georgia PSC on September 3, 2013, which reflected approximately $2.4 billion of total construction capital costs incurred through June 30, 2013. On October 15, 2013, the Georgia PSC voted to approve the Company's eighth VCM report, reflecting construction capital costs incurred, which through December 31, 2012 totaled approximately $2.2 billion. Also in accordance with the stipulation, the Company will file with the Georgia PSC on February 28, 2014 a combined ninth and tenth VCM report covering the period from January 1 through December 31, 2013 (Ninth/Tenth VCM report), which will request approval for an additional $0.4 billion of construction capital costs. The Ninth/Tenth VCM report will reflect estimated in-service construction capital costs of $4.8 billion and associated financing costs during the construction period, which are estimated to total approximately $2.0 billion. The Company expects to resume filing semi-annual VCM reports in August 2014.

In July 2012, the Owners and the Contractor began negotiations regarding the costs associated with design changes to the DCD and the delays in the timing of approval of the DCD and issuance of the COLs, including the assertion by the Contractor that the Owners are responsible for these costs under the terms of the Vogtle 3 and 4 Agreement. The portion of the additional costs claimed by the Contractor that would be attributable to the Company (based on the Company's ownership interest) with respect to these issues is approximately $425 million (in 2008 dollars). The Contractor also has asserted it is entitled to further schedule extensions. The Company has not agreed with either the proposed cost or schedule adjustments or that the Owners have any responsibility for costs related to these issues. In November 2012, the Company and the other Owners filed suit against the Contractor in the U.S. District Court for the Southern District of Georgia seeking a declaratory judgment that the Owners are not responsible for these costs. Also in November 2012, the Contractor filed suit against the Company and the other Owners in the U.S. District Court for the District of Columbia alleging the Owners are responsible for these costs. On August 30, 2013, the U.S. District Court for the District of Columbia dismissed the Contractor's suit, ruling that the proper venue is the U.S. District Court for the Southern District of Georgia. The Contractor appealed the decision to the U.S. Court of Appeals for the District of Columbia Circuit on September 27, 2013. While litigation has commenced and the Company intends to vigorously defend its positions, the Company also expects negotiations with the Contractor to continue with respect to cost and schedule during which negotiations the parties may reach a mutually acceptable compromise of their positions.

Processes are in place that are designed to assure compliance with the requirements specified in the DCD and the COLs, including inspections by Southern Nuclear and the NRC that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the NRC. Various design and other licensing-based compliance issues are expected to arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs either to the Owners, the Contractor, or both.

As construction continues, the risk remains that additional challenges in the fabrication, assembly, delivery, and installation of structural modules, delays in the receipt of the remaining permits necessary for the operation of Plant Vogtle Units 3 and 4, or other issues could arise and may further impact project schedule and cost. Additional claims by the Contractor or the Company (on behalf of the Owners) are also likely to arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the Vogtle 3 and 4 Agreement, but also may be resolved through litigation.

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

4. JOINT OWNERSHIP AGREEMENTS

The Company and Alabama Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 MWs, as well as associated transmission facilities. The capacity of these units is sold equally to the Company and Alabama Power under a power contract. The Company and Alabama Power make payments sufficient to provide for the operating expenses, taxes, interest expense, and a return on equity. The Company's share of purchased power totaled $91 million in 2013, $107 million in 2012, and $141 million in 2011 and is included in purchased power, affiliates in the statements of income. The Company accounts for SEGCO using the equity method.

The Company owns undivided interests in Plants Vogtle, Hatch, Wansley, and Scherer in varying amounts jointly with one or more of the following entities: OPC, MEAG Power, Dalton, Florida Power & Light Company, Jacksonville Electric Authority, and Gulf Power. Under these agreements, the Company has been contracted to operate and maintain the plants as agent for the co-owners and is jointly and severally liable for third party claims related to these plants. In addition, the Company jointly owns the Rocky Mountain pumped storage hydroelectric plant with OPC who is the operator of the plant. The Company and Duke Energy Florida, Inc. jointly own a combustion turbine unit (Intercession City) operated by Duke Energy Florida, Inc.

At December 31, 2013, the Company's percentage ownership and investment (exclusive of nuclear fuel) in jointly-owned facilities in commercial operation with the above entities were as follows:

Facility (Type)	Company Ownership	Plant in Service	Accumulated Depreciation	CWIP
		(in millions)		
Plant Vogtle (nuclear)				
Units 1 and 2	45.7%	$ 3,375	$ 2,028	$ 53
Plant Hatch (nuclear)	50.1	1,092	551	52
Plant Wansley (coal)	53.5	800	260	36
Plant Scherer (coal)				
Units 1 and 2	8.4	209	80	24
Unit 3	75.0	1,155	398	19
Rocky Mountain (pumped storage)	25.4	182	120	—
Intercession City (combustion-turbine)	33.3	14	4	—

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

The Company also owns 45.7% of Plant Vogtle Units 3 and 4 that are currently under construction. See Note 3 under "Retail Regulatory Matters – Nuclear Construction" for additional information.

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. 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
		(in millions)	
Federal –			
Current	$ 277	$ 273	$ 106
Deferred	374	370	479
	651	643	585
State –			
Current	(30)	38	19
Deferred	102	7	21
	72	45	40
Total	$ 723	$ 688	$ 625

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
	(in millions)	
Deferred tax liabilities –		
Accelerated depreciation	$ 4,479	$ 4,201
Property basis differences	873	757
Employee benefit obligations	232	255
Premium on reacquired debt	73	77
Regulatory assets associated with employee benefit obligations	276	536
Asset retirement obligations	495	446
Other	168	93
Total	6,596	6,365
Deferred tax assets –		
Federal effect of state deferred taxes	159	142
Employee benefit obligations	388	644
Other property basis differences	93	100
Other deferred costs	84	39
Cost of removal obligations	17	29
State tax credit carry forward	118	86
Federal tax credit carry forward	3	—
Over-recovered fuel costs	22	89
Unbilled fuel revenue	53	39
Asset retirement obligations	495	446
Other	32	42
Total	1,464	1,656
Total deferred tax liabilities, net	5,132	4,709
Portion included in current assets/(liabilities), net	68	152
Accumulated deferred income taxes	$ 5,200	$ 4,861

At December 31, 2013, tax-related regulatory assets were $722 million. These assets are primarily attributable to tax benefits flowed through to customers in prior years, deferred taxes previously recognized at rates lower than the current enacted tax law, and taxes applicable to capitalized interest.

At December 31, 2013, tax-related regulatory liabilities to be credited to customers were $112 million. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than current enacted tax law and to unamortized ITCs. In 2011, the Company recorded a regulatory liability of $62 million related to a settlement with the Georgia Department of Revenue resolving claims for certain tax credits in 2005 through 2009. Amortization of the regulatory liability occurred ratably over the period from April 2012 through December 2013.

In accordance with regulatory requirements, deferred federal 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 $5 million in 2013, $13 million in 2012, and $9 million in 2011. State ITCs are recognized in the period in which the credits are claimed on the state income tax return and totaled $27 million in 2013, $36 million in 2012, and $53 million in 2011. At December 31, 2013, the Company had $3 million in federal tax credit carry forwards that will expire by 2032 and $118 million in state ITC carry forwards that will expire between 2020 and 2024.

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.

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	**2.5**	1.6	1.5
Non-deductible book depreciation	**1.3**	1.2	0.8
AFUDC equity	**(0.6)**	(1.0)	(1.9)
Other	**(0.4)**	(0.1)	(0.5)
Effective income tax rate	**37.8%**	36.7%	34.9%

The increase in the Company's 2013 effective tax rate is primarily the result of a decrease in state income tax credits and non-taxable AFUDC equity. The increase in the Company's 2012 effective tax rate is primarily the result of an increase in non-deductible book depreciation and a decrease in non-taxable AFUDC equity.

Unrecognized Tax Benefits

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

	2013	2012	2011
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ 23**	$ 47	$ 237
Tax positions from current periods	**—**	3	9
Tax positions increase from prior periods	**—**	3	—
Tax positions decrease from prior periods	**(23)**	(19)	(87)
Reductions due to settlements	**—**	(8)	(112)
Reductions due to expired statute of limitations	**—**	(3)	—
Balance at end of year	**$ —**	$ 23	$ 47

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.

In addition, the tax reductions due to expired statute of limitations for 2012 relate to the Georgia jobs and retraining tax credits and the Georgia manufacturer's ITCs.

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

	2013	2012	2011
		(in millions)	
Tax positions impacting the effective tax rate	**$ —**	$ —	$ 28
Tax positions not impacting the effective tax rate	**—**	23	19
Balance of unrecognized tax benefits	**$ —**	$ 23	$ 47

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

Accrued interest for unrecognized tax benefits was as follows:

	2013	2012	2011
		(in millions)	
Interest accrued at beginning of year	**$ —**	$ 6	$ 27
Interest reclassified due to settlements	**—**	(6)	(24)
Interest accrued during the year	**—**	—	3
Balance at end of year	**$ —**	$ —	$ 6

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

It is reasonably possible that the amount of the unrecognized tax benefits 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

Securities Due Within One Year

A summary of scheduled maturities of long-term debt due within one year at December 31 was as follows:

	2013	2012
	(in millions)	
Senior notes	**$ —**	$ 1,675
Capital lease	**5**	5
Total	**$ 5**	$ 1,680

Maturities through 2018 applicable to total long-term debt are as follows: $5 million in 2014; $1.1 billion in 2015; $710 million in 2016; $457 million in 2017; and $277 million in 2018.

Senior Notes

The Company issued $850 million aggregate principal amount of unsecured senior notes in 2013. The proceeds of these issuances were used to fund a portion of the Company's repayment of $1.8 billion of unsecured senior notes and $300 million of an unsecured bank term loan, to repay a portion of the Company's short-term indebtedness, and for general corporate purposes, including the Company's continuous construction program.

At December 31, 2013 and 2012, the Company had $6.9 billion and $7.9 billion of senior notes outstanding, respectively. These senior notes are effectively subordinated to all secured debt of the Company, which aggregated $45 million and $50 million at December 31, 2013 and 2012, respectively. As of December 31, 2013 and 2012, the Company's secured debt was related to capital lease obligations.

See "DOE Loan Guarantee Borrowings" for information regarding additional secured borrowings incurred by the Company subsequent to December 31, 2013.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2013 and 2012 was $1.7 billion and $1.8 billion, respectively. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

In 2013, the Company incurred obligations in connection with issuance by public authorities of an aggregate of $194 million of pollution control revenue bonds. The proceeds of these issuances were used to redeem $194 million of outstanding pollution control bonds. Also in November 2013, the Company purchased and now holds $104.6 million aggregate principal amount of pollution control revenue bonds issued for its benefit in 2013.

Bank Term Loans

In March 2013, the Company entered into three 60-day floating rate bank loans bearing interest based on one-month London Interbank Offered Rate (LIBOR). Each of these short-term loans was for $100 million aggregate principal amount, and the proceeds were used for working capital and other general corporate purposes, including the Company's continuous construction program. These bank loans were repaid at maturity.

In November 2013, the Company entered into three four-month floating rate bank loans for an aggregate principal amount of $400 million, bearing interest based on one-month LIBOR. The proceeds of these short-term loans were used for working capital and other general corporate purposes, including the Company's continuous construction program. At December 31, 2013, these bank term loans are included in notes payable on the balance sheets. Subsequent to December 31, 2013, the Company repaid these bank term loans. There were no bank term loans outstanding at December 31, 2012.

These bank loans have covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes long-term debt payable to affiliated trusts and other hybrid securities. At December 31, 2013, the Company was in compliance with its debt limits.

DOE Loan Guarantee Borrowings

Pursuant to the loan guarantee program established under Title XVII of the Energy Policy Act of 2005 (Title XVII Loan Guarantee Program), the Company and the DOE entered into a loan guarantee agreement (Loan Guarantee Agreement) on February 20, 2014, under which the DOE agreed to guarantee the obligations of the Company under a note purchase agreement (FFB Note Purchase Agreement) among the DOE, the Company, and the Federal Financing Bank (FFB) and a related promissory note (FFB Promissory Note). The FFB Note Purchase Agreement and the FFB Promissory Note provide for a multi-advance term loan facility (FFB Credit Facility), under which the Company may make term loan borrowings through the FFB.

Proceeds of advances made under the FFB Credit Facility will be used to reimburse the Company for a portion of certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the Title XVII Loan Guarantee Program (Eligible Project Costs). Aggregate borrowings under the FFB Credit Facility may not exceed the lesser of (i) 70% of Eligible Project Costs or (ii) approximately $3.46 billion.

All borrowings under the FFB Credit Facility are full recourse to the Company, and the Company is obligated to reimburse the DOE in the event the DOE is required to make any payments to FFB under the DOE guarantee. The Company's reimbursement obligations to the DOE are secured by a first priority lien on (i) the Company's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 and (ii) the Company's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. There are no restrictions on the Company's ability to grant liens on other property.

Advances may be requested under the FFB Credit Facility on a quarterly basis through December 31, 2020. The final maturity date for each advance under the FFB Credit Facility is February 20, 2044. Interest is payable quarterly and principal payments will begin on February 20, 2020. Borrowings under the FFB Credit Facility will bear interest at the applicable U.S. Treasury rate plus a spread equal to 0.375%.

On February 20, 2014, the Company made initial borrowings under the FFB Credit Facility in an aggregate principal amount of $1.0 billion. The interest rate applicable to $500 million of the initial advance under the FFB Credit Facility is 3.860% for an interest period that extends to February 20, 2044 (the final maturity date) and the interest rate applicable to the remaining $500 million is 3.488% for an interest period that extends to February 20, 2029, and will be reset from time to time thereafter through the final maturity date. In connection with its entry into the Loan Guarantee Agreement, the FFB Note Purchase Agreement, and the FFB Promissory Note, the Company incurred issuance costs of approximately $67 million, which will be amortized over the life of the borrowings under the FFB Credit Facility.

Future advances are subject to satisfaction of customary conditions, as well as certification of compliance with the requirements of the Title XVII Loan Guarantee Program, including accuracy of project-related representations and warranties, delivery of updated project-related information, and evidence of compliance with the prevailing wage requirements of the Davis-Bacon Act of 1931, as amended, compliance with the Cargo Preference Act of 1954, and certification from the DOE's consulting engineer that proceeds of the advances are used to reimburse Eligible Project Costs.

Under the Loan Guarantee Agreement, the Company is subject to customary borrower affirmative and negative covenants and events of default. In addition, the Company is subject to project-related reporting requirements and other project-specific covenants and events of default.

In the event certain mandatory prepayment events occur, the FFB’s commitment to make further advances under the FFB Credit Facility will terminate and the Company will be required to prepay the outstanding principal amount of all borrowings under the FFB Credit Facility over a period of five years (with level principal amortization). Under certain circumstances, insurance proceeds and any proceeds from an event of taking must be applied to immediately prepay outstanding borrowings under the FFB Credit Facility. The Company also may voluntarily prepay outstanding borrowings under the FFB Credit Facility. Under the FFB Promissory Note, any prepayment (whether mandatory or optional) will be made with a make-whole premium or discount, as applicable.

In connection with any cancellation of Plant Vogtle Units 3 and 4 that results in a mandatory prepayment event, the DOE may elect to continue construction of Plant Vogtle Units 3 and 4. In such an event, the DOE will have the right to assume the Company’s rights and obligations under the principal agreements relating to Plant Vogtle Units 3 and 4 and to acquire all or a portion of the Company’s ownership interest in Plant Vogtle Units 3 and 4.

Capital Leases

Assets acquired under capital leases are recorded in the balance sheets as utility plant in service, and the related obligations are classified as long-term debt. At December 31, 2013 and 2012, the Company had a capital lease asset for its corporate headquarters building of $61 million, with accumulated depreciation at December 31, 2013 and 2012 of $16 million and $11 million, respectively. At December 31, 2013 and 2012, the capitalized lease obligation was $45 million and $50 million, respectively, with an interest rate of 7.9% for both years. For ratemaking purposes, the Georgia PSC has allowed only the lease payments in cost of service. The difference between the accrued expense and the lease payments allowed for ratemaking purposes has been deferred and is being amortized to expense as ordered by the Georgia PSC. The annual expense incurred for all capital leases was not material for any year presented. See Note 7 under "Fuel and Purchased Power Agreements" for additional information on capital lease PPAs that become effective in 2015.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company has shares of its Class A preferred stock, preference stock, and common stock outstanding. The Company's Class A preferred stock ranks senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. The outstanding series of the Class A preferred stock is subject to redemption at the option of the Company at any time at a redemption price equal to 100% of the par value. In addition, on or after October 1, 2017, the Company may redeem the outstanding series of the preference stock at a redemption price equal to 100% of the par value. With respect to any redemption of the preference stock prior to October 1, 2017, the redemption price includes a make-whole premium based on the present value of the liquidation amount and future dividends through the first par redemption date.

Dividend Restrictions

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

Bank Credit Arrangements

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

Expires[a]			
2016	2018	Total	Unused
	(in millions)		
$150	$1,600	$1,750	$1,736

(a) No credit arrangements expire in 2014, 2015, or 2017.

The Company expects to renew its credit arrangements, as needed, prior to expiration. All the credit arrangements require payment of commitment fees based on the unused portion of the commitments. Commitment fees average less than 1/4 of 1% for the Company.

The credit arrangements have covenants that limit the Company's debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes certain hybrid securities.

A portion of the $1.7 billion of unused credit arrangements with banks is allocated to provide liquidity support to the Company's variable rate pollution control revenue bonds and its commercial paper borrowings. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2013 was $862 million. In addition, at December 31, 2013, the Company had $242 million of fixed rate pollution control revenue bonds that will be required to be remarketed within the next 12 months.

The Company makes short-term borrowings primarily through a commercial paper program that has the liquidity support of the Company's committed bank credit arrangements. The Company may also borrow through various other arrangements with banks. Commercial paper and short-term bank term loans are included in notes payable on the balance sheets.

The Company had $1.0 billion of short-term debt outstanding at December 31, 2013. The Company had no short-term debt outstanding at December 31, 2012, excluding $2 million of notes payable related to other energy service contracts. Details of short-term borrowings outstanding at December 31, 2013 were as follows:

	Short-term Debt at the End of the Period	
	Amount Outstanding	Weighted Average Interest Rate
	(in millions)	
December 31, 2013:		
Commercial paper	$ 647	0.2%
Short-term bank debt	400	0.9%
Total	$ 1,047	0.5%

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 $2.3 billion, $2.1 billion, and $2.8 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.

The Company has commitments regarding a portion of a 5% interest in the original cost of Plant Vogtle Units 1 and 2 owned by MEAG Power that are in effect until the latter of the retirement of the plant or the latest stated maturity date of MEAG Power's bonds issued to finance such ownership interest. The payments for capacity are required whether or not any capacity is available. The energy cost is a function of each unit's variable operating costs. Portions of the capacity payments relate to costs in excess of MEAG Power's Plant Vogtle Unit 1 and 2 allowed investment for ratemaking purposes. The present value of these portions at the time of the disallowance was written off. Generally, the cost of such capacity and energy is included in purchased power, non-affiliates in the statements of income. Capacity payments totaled $27 million, $50 million, and $52 million in 2013, 2012, and 2011, respectively.

The Company has also entered into various long-term PPAs, some of which are accounted for as capital or operating leases. Total capacity expense under PPAs accounted for as operating leases was $162 million, $169 million, and $216 million for 2013, 2012, and 2011, respectively. Estimated total long-term obligations at December 31, 2013 were as follows:

	Affiliate Capital Leases	Non-Affiliate Capital Leases [4]	Affiliate Operating Leases	Non-Affiliate Operating Leases [4]	Vogtle Units 1 and 2 Capacity Payments	Total ($)
			(in millions)			
2014	$ —	$ —	$ 55	$ 112	$ 21	$ 188
2015	22	20	89	127	13	271
2016	22	26	99	142	11	300
2017	23	27	71	144	8	273
2018	23	27	62	145	7	264
2019 and thereafter	278	541	669	1,573	58	3,119
Total	$ 368	$ 641	$ 1,045	$ 2,243	$ 118	$ 4,415
Less: amounts representing executory costs[1]	55	142				
Net minimum lease payments	313	499				
Less: amounts representing interest[2]	85	166				
Present value of net minimum lease payments[3]	$ 228	$ 333				

(1) Executory costs such as taxes, maintenance, and insurance (including the estimated profit thereon) are estimated and included in total minimum lease payments.
(2) Calculated at the Company's incremental borrowing rate at the inception of the leases.
(3) When the PPAs begin in 2015, the Company will recognize capital lease assets and capital lease obligations totaling $482 million, equal to the lesser of the present value of the net minimum lease payments or the estimated fair value of the leased property.
(4) A total of $1.3 billion of biomass PPAs included under the non-affiliate capital and operating leases is contingent upon the counterparty meeting specified contract dates for posting collateral and commercial operation.

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 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

In addition to the PPA operating leases discussed above, the Company has other operating lease agreements with various terms and expiration dates. Total rent expense was $32 million for 2013, $34 million for 2012, and $33 million for 2011. The Company includes any step rents, fixed escalations, and lease concessions in its computation of minimum lease payments.

As of December 31, 2013, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Railcars	Other	Total
		(in millions)	
2014	$ 20	$ 6	$ 26
2015	14	6	20
2016	8	5	13
2017	5	4	9
2018	2	4	6
2019 and thereafter	—	11	11
Total	$ 49	$ 36	$ 85

Railcar minimum lease payments are disclosed at 100% of railcar lease obligations; however, a portion of these obligations is shared with the joint owners of Plants Scherer and Wansley. A majority of the rental expenses related to the railcar leases are recoverable through the fuel cost recovery clause as ordered by the Georgia PSC and the remaining portion is recovered through base rates.

In addition to the above rental commitments, the Company has obligations upon expiration of certain railcar leases with respect to the residual value of the leased property. These leases have terms expiring through 2018 with maximum obligations under these leases of $30 million. 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

Alabama Power has guaranteed the obligations 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. The Company has agreed to reimburse Alabama Power for the pro rata portion of such obligations corresponding to the Company's then proportionate ownership of SEGCO's stock if Alabama Power is called upon to make such payment under its guarantee. See Note 4 for additional information.

In addition, subsequent to December 31, 2013, the Company entered into an agreement that requires the Company to guarantee certain payments of a gas supplier for Plant McIntosh for a period up to 15 years. The guarantee is expected to be terminated if certain events occur within one year of the initial gas deliveries in 2017. In the event the gas supplier defaults on payments, the maximum potential exposure under the guarantee is approximately $43 million.

As discussed earlier in this Note under "Operating Leases," the Company has entered into certain residual value guarantees related to railcar leases.

8. STOCK COMPENSATION

Stock Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2013, there were 1,265 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.

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

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

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

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

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2012	6,547,498	$ 36.18
Granted	1,509,662	44.09
Exercised	(1,196,585)	33.38
Cancelled	(11,421)	40.99
Outstanding at December 31, 2013	**6,849,154**	**$ 38.41**
Exercisable at December 31, 2013	**4,321,853**	**$ 35.51**

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 $27 million and $26 million, respectively.

As of December 31, 2013, the amount of unrecognized compensation cost related to stock option awards not yet vested was immaterial.

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

The total intrinsic value of options exercised during the years ended December 31, 2013, 2012, and 2011 was $16 million, $34 million, and $32 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $6 million, $13 million, and $12 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.

The fair value of performance share awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period. The Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. The expected volatility was based on the historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the performance period of the award units.

The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of performance share award units granted:

Year Ended December 31	2013	2012	2011
Expected volatility	**12.0%**	16.0%	19.2%
Expected term *(in years)*	**3.0**	3.0	3.0
Interest rate	**0.4%**	0.4%	1.4%
Annualized dividend rate	**$1.96**	$1.89	$1.82
Weighted average grant-date fair value	**$40.50**	$41.99	$35.97

Total unvested performance share units outstanding as of December 31, 2012 were 280,000. During 2013, 161,240 performance share units were granted, 151,769 performance shares were vested, and 16,371 performance share units were forfeited, resulting in 273,100 unvested units outstanding at December 31, 2013. In January 2014, the vested performance share award units were converted into 45,239 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 $6 million, $6 million, and $4 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 Hatch and Plant Vogtle Units 1 and 2. The Act provides funds up to $13.6 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. The Company could be assessed up to $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, based on its ownership and buyback interests in all licensed reactors, is $252 million, per incident, but not more than an aggregate of $37 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. See Note 4 to the financial statements herein for additional information on joint ownership agreements.

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 replacement power, subject to ownership limitations. Each facility has elected a 12-week deductible waiting period.

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

Under each of the NEIL policies, members are subject to assessments 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 $65 million.

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

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the Company or to its debt trustees as may be appropriate under the policies and applicable trust indentures. In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers, would be borne by the Company and could have a material effect on the Company's financial condition and results of operations.

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

10. FAIR VALUE MEASUREMENTS

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

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

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

As of December 31, 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:

	Fair Value Measurements Using			
As of December 31, 2013:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Energy-related derivatives	$ —	$ 5	$ —	$ 5
Nuclear decommissioning trusts:[(a)]				
Domestic equity	197	1	—	198
Foreign equity	—	131	—	131
U.S. Treasury and government agency securities	—	79	—	79
Municipal bonds	—	64	—	64
Corporate bonds	—	140	—	140
Mortgage and asset backed securities	—	114	—	114
Other investments	—	24	—	24
Total	$ 197	$ 558	$ —	$ 755
Liabilities:				
Energy-related derivatives	$ —	$ 21	$ —	$ 21

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

As of December 31, 2012, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2012:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Energy-related derivatives	$ —	$ 11	$ —	$ 11
Nuclear decommissioning trusts:[a]				
Domestic equity	162	1	—	163
Foreign equity	—	117	—	117
U.S. Treasury and government agency securities	—	105	—	105
Municipal bonds	—	55	—	55
Corporate bonds	—	133	—	133
Mortgage and asset backed securities	—	115	—	115
Other investments	—	10	—	10
Cash equivalents	15	—	—	15
Total	$ 177	$ 547	$ —	$ 724
Liabilities:				
Energy-related derivatives	$ —	$ 45	$ —	$ 45

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

Valuation Methodologies

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

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

A market price secured from the primary source vendor is then 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:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
As of December 31, 2013:	*(in millions)*			
Nuclear decommissioning trusts:				
Foreign equity fund	$ 131	None	Daily	5 days
Corporate bonds — commingled funds	8	None	Daily	Not applicable
Other — commingled funds	24	None	Daily	Not applicable
As of December 31, 2012:				
Nuclear decommissioning trusts:				
Foreign equity fund	$ 117	None	Daily	5 days
Corporate bonds — commingled funds	9	None	Daily	Not applicable
Other — commingled funds	10	None	Daily	Not applicable
Cash equivalents:				
Money market funds	15	None	Daily	Not applicable

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The foreign equity fund in the nuclear decommissioning trusts seeks to provide long-term capital appreciation. In pursuing this investment objective, the foreign equity fund primarily invests in a diversified portfolio of equity securities of foreign companies, including those in emerging markets. These equity securities may include, but are not limited to, common stocks, preferred stocks, real estate investment trusts, convertible securities and depositary receipts, including American depositary receipts, European depositary receipts and global depositary receipts, and rights and warrants to buy common stocks. The Company may withdraw all or a portion of its investment on the last business day of each month subject to a minimum withdrawal of $1 million, provided that a minimum investment of $10 million remains. If notices of withdrawal exceed 20% of the aggregate value of the foreign equity fund, then the foreign equity fund's board may refuse to permit the withdrawal of all such investments and may scale down the amounts to be withdrawn pro rata and may further determine that any withdrawal that has been postponed will have priority on the subsequent withdrawal date.

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

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

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

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2013	**$ 8,593**	**$ 8,782**
2012	$ 9,624	$ 10,427

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on 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 a fuel-hedging program, implemented per the guidelines of the Georgia 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 gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

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

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

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

At December 31, 2013, the net volume of energy-related derivative contracts for natural gas positions totaled 60 million mmBtu (million British thermal units), all of which expire by 2017, which is the longest hedge date.

In addition to the volume discussed above, the Company enters into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The expected volume of natural gas subject to such a feature is 5 million mmBtu for the Company.

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 income.

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 immaterial. The Company has deferred gains and losses related to interest rate derivative settlements that are expected to be amortized into earnings through 2037.

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:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2013**	2012	**Balance Sheet Location**	**2013**	2012
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ 3**	$ 6	Liabilities from risk management activities	**$ 13**	$ 30
	Other deferred charges and assets	**2**	5	Other deferred credits and liabilities	**8**	15
Total derivatives designated as hedging instruments for regulatory purposes		**$ 5**	$ 11		**$ 21**	$ 45

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

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 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.

Fair Value					
Assets	**2013**	2012	**Liabilities**	**2013**	2012
	(in millions)			*(in millions)*	
Energy-related derivatives presented in the Balance Sheet [(a)]	**$ 5**	$ 11	Energy-related derivatives presented in the Balance Sheet [(a)]	**$ 21**	$ 45
Gross amounts not offset in the Balance Sheet [(b)]	**(5)**	(11)	Gross amounts not offset in the Balance Sheet [(b)]	**(5)**	(11)
Net-energy related derivative assets	**$ —**	$ —	**Net-energy related derivative liabilities**	**$ 16**	$ 34

(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 effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets were as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2013**	2012	**Balance Sheet Location**	**2013**	2012
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$ (13)**	$ (30)	Other regulatory liabilities, current	**$ 3**	$ 6
	Other regulatory assets, deferred	**(8)**	(15)	Other deferred credits and liabilities	**2**	5
Total energy-related derivative gains (losses)		**$ (21)**	$ (45)		**$ 5**	$ 11

For the years ended December 31, 2013, 2012, and 2011, the pre-tax effects of interest rate derivatives designated as cash flow hedging instruments recognized in OCI and those reclassified from accumulated OCI into income were immaterial.

There was no material ineffectiveness recorded in earnings for any period presented. The pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was immaterial for all years presented.

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 $3 million.

At December 31, 2013, the Company had no collateral posted with its derivative counterparties; however, because of the joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $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.

12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

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

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
		(in millions)	
March 2013	**$ 1,882**	**$ 412**	**$ 197**
June 2013	**2,042**	**552**	**282**
September 2013	**2,484**	**872**	**487**
December 2013	**1,866**	**404**	**208**
March 2012	$ 1,745	$ 344	$ 167
June 2012	2,020	535	295
September 2012	2,498	924	525
December 2012	1,735	400	181

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

	2013	2012	2011	2010	2009
Operating Revenues (in millions)	**$ 8,274**	$ 7,998	$ 8,800	$ 8,349	$ 7,692
Net Income After Dividends on Preferred and Preference Stock (in millions)	**$ 1,174**	$ 1,168	$ 1,145	$ 950	$ 814
Cash Dividends on Common Stock (in millions)	**$ 907**	$ 983	$ 1,096	$ 820	$ 739
Return on Average Common Equity (percent)	**12.45**	12.76	12.89	11.42	11.01
Total Assets (in millions)	**$ 28,907**	$ 28,803	$ 27,151	$ 25,914	$ 24,295
Gross Property Additions (in millions)	**$ 1,906**	$ 1,838	$ 1,981	$ 2,401	$ 2,646
Capitalization (in millions):					
Common stock equity	**$ 9,591**	$ 9,273	$ 9,023	$ 8,741	$ 7,903
Preferred and preference stock	**266**	266	266	266	266
Long-term debt	**8,633**	7,994	8,018	7,931	7,782
Total (excluding amounts due within one year)	**$ 18,490**	$ 17,533	$ 17,307	$ 16,938	$ 15,951
Capitalization Ratios (percent):					
Common stock equity	**51.9**	52.9	52.1	51.6	49.5
Preferred and preference stock	**1.4**	1.5	1.5	1.6	1.7
Long-term debt	**46.7**	45.6	46.4	46.8	48.8
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**2,080,358**	2,062,040	2,047,390	2,049,770	2,043,661
Commercial	**299,340**	297,294	296,143	296,140	295,375
Industrial	**8,216**	8,246	8,279	8,136	8,202
Other	**8,623**	7,724	7,521	7,309	6,580
Total	**2,396,537**	2,375,304	2,359,333	2,361,355	2,353,818
Employees (year-end)	**7,886**	8,094	8,310	8,330	8,599

SELECTED FINANCIAL AND OPERATING DATA 2009-2013 (continued)
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	2013	2012	2011	2010	2009
Operating Revenues (in millions):					
Residential	**$ 3,058**	$ 2,986	$ 3,241	$ 3,072	$ 2,686
Commercial	**3,077**	2,965	3,217	3,011	2,826
Industrial	**1,391**	1,322	1,547	1,441	1,318
Other	**94**	89	94	84	82
Total retail	**7,620**	7,362	8,099	7,608	6,912
Wholesale — non-affiliates	**281**	281	341	380	395
Wholesale — affiliates	**20**	20	32	53	112
Total revenues from sales of electricity	**7,921**	7,663	8,472	8,041	7,419
Other revenues	**353**	335	328	308	273
Total	**$ 8,274**	$ 7,998	$ 8,800	$ 8,349	$ 7,692
Kilowatt-Hour Sales (in millions):					
Residential	**25,479**	25,742	27,223	29,433	26,272
Commercial	**31,984**	32,270	32,900	33,855	32,593
Industrial	**23,087**	23,089	23,519	23,209	21,810
Other	**630**	641	657	663	671
Total retail	**81,180**	81,742	84,299	87,160	81,346
Wholesale — non-affiliates	**3,029**	2,934	3,904	4,662	5,208
Wholesale — affiliates	**496**	600	626	1,000	2,504
Total	**84,705**	85,276	88,829	92,822	89,058
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**12.00**	11.60	11.91	10.44	10.22
Commercial	**9.62**	9.19	9.78	8.89	8.67
Industrial	**6.03**	5.73	6.58	6.21	6.04
Total retail	**9.39**	9.01	9.61	8.73	8.50
Wholesale	**8.54**	8.52	8.23	7.65	6.57
Total sales	**9.35**	8.99	9.54	8.66	8.33
Residential Average Annual Kilowatt-Hour Use Per Customer	**12,293**	12,509	13,288	14,367	12,848
Residential Average Annual Revenue Per Customer	**$ 1,475**	$ 1,451	$ 1,582	$ 1,499	$ 1,314
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**17,586**	17,984	16,588	15,992	15,995
Maximum Peak-Hour Demand (megawatts):					
Winter	**12,767**	14,104	14,800	15,614	15,173
Summer	**15,228**	16,440	16,941	17,152	16,080
Annual Load Factor (percent)	**63.5**	59.1	59.5	60.9	60.7
Plant Availability (percent)*:					
Fossil-steam	**87.1**	90.3	88.6	88.6	92.5
Nuclear	**91.8**	94.1	92.2	94.0	88.4
Source of Energy Supply (percent):					
Coal	**26.4**	26.6	44.4	51.8	52.3
Nuclear	**17.7**	18.3	16.6	16.4	16.2
Hydro	**2.0**	0.7	1.1	1.4	1.8
Oil and gas	**29.6**	22.0	8.9	8.0	7.7
Purchased power -					
From non-affiliates	**3.3**	6.8	6.1	5.2	4.4
From affiliates	**21.0**	25.6	22.9	17.2	17.6
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
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Directors

W. Paul Bowers
President and Chief Executive Officer
Georgia Power Company

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

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

Thomas A. Fanning
Chairman, President, and Chief Executive Officer
The Southern Company

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

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

Charles K. Tarbutton
Assistant Vice President
Sandersville Railroad Company

Beverly Daniel Tatum
President
Spelman College

D. Gary Thompson
Retired Chief Executive Officer
Wachovia Corporation

Clyde C. Tuggle
Senior Vice President, Chief Public Affairs and Communications Officer
The Coca-Cola Company

Richard W. Ussery
Retired Chairman and Chief Executive Officer
Total System Services, Inc.

Officers

W. Paul Bowers
President and Chief Executive Officer
Georgia Power Company

W. Craig Barrs
Executive Vice President
External Affairs

W. Ron Hinson
Executive Vice President, Chief Financial Officer, and Treasurer

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

Anthony L. Wilson
Executive Vice President
Customer Service and Operations

Michael K. Anderson
Senior Vice President
Charitable Giving

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

Walter Dukes
Senior Vice President
Metro Atlanta Regions

Michael A. Hazelton (Elected Senior Vice President effective 1/2/2014)
Senior Vice President
Marketing

John L. Pemberton
Senior Vice President and
Senior Production Officer

Tami M. Barron (Elected effective 1/4/2014)
Vice President
Supply Chain Management

Melissa K. Caen
Assistant Secretary

Moanica M. Caston
Vice President
Diversity and Inclusion

DIRECTORS AND OFFICERS
Georgia Power Company 2013 Annual Report

Lenn H. Chandler
Vice President
Northeast Region

Pedro P. Cherry
Vice President
Community and Economic Development

P. Mike Clanton
Vice President
Land

Jason T. Cuevas
Vice President
Corporate Communication

J. Truitt Eavenson (Effective 3/29/2014)
Vice President
Governmental and Regulatory Affairs

Jim R. Fletcher (Resigned effective 3/29/2014)
Vice President
Governmental and Regulatory Affairs

Fran G. Forehand (Elected effective 3/29/2014)
Vice President
East Region

Cathy P. Hill
Vice President
Coastal Region

Anne H. Kaiser
Vice President
Northwest Region

Stacy R. Kilcoyne
Vice President
Human Resource Services

Danny W. Lindsey
Vice President
Transmission

Earl C. Long
Assistant Treasurer

Jacki W. Lowe
Vice President
West Region

Terri H. Lupo
Vice President
South Region

William N. (Norrie) McKenzie (Elected effective 9/1/2013)
Vice President
Renewable Development

Leonard Owens
Vice President
Human Resources and Labor

Laura I. Patterson (Elected Comptroller effective 1/17/2014)
Comptroller and Assistant Secretary

Gregory N. Roberts
Vice President
Pricing and Planning

Louise L. Scott (Effective 3/29/2014)
Vice President
Customer Services

Ronald Shipman
Vice President
Environmental Affairs

Leslie R. Sibert
Vice President
Distribution

Elliott L. Spencer (Resigned effective 1/17/2014)
Assistant Comptroller

H. Murray Weaver II
Vice President
Sales

Thomas J. Wicker
Vice President
Central Region

James D. Wynn, Jr.
Vice President
Corporate Services

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 Georgia and to wholesale customers in the Southeast. The Company sells electricity to approximately 2.4 million customers within its service area. In 2013, retail energy sales accounted for 96% of the Company's total sales of 84.7 billion kilowatt-hours.

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

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

Registrar, Transfer Agent, and Dividend Paying Agent
For Preferred Stock and Preference Stock
Computershare Inc.
P.O. Box 30170
College Station, TX 77842-3170
(800) 554-7626
www.computershare.com/investor

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

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

Quarter	2013	2012
	(in thousands)	
First	$226,750	$227,075
Second	226,750	227,075
Third	226,750	227,075
Fourth	226,750	302,075

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

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

Georgia Power Company
241 Ralph McGill Boulevard, N.E.
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