GEORGIA POWER COMPANY

2014 ANNUAL REPORT

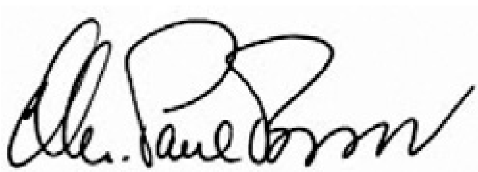
GEORGIA POWER

A SOUTHERN COMPANY

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Georgia Power Company 2014 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 (2013)* 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, 2014.



W. Paul Bowers
Chairman, President, and Chief Executive Officer

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

March 2, 2015

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, 2014 and 2013, 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, 2014. 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 80) present fairly, in all material respects, the financial position of Georgia Power Company as of December 31, 2014 and 2013, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
March 2, 2015

DEFINITIONS

Term	Meaning
2013 ARP	Alternative Rate Plan approved by the Georgia PSC for Georgia Power for the years 2014 through 2016
AFUDC	Allowance for funds used during construction
Alabama Power	Alabama Power Company
ASC	Accounting Standards Codification
CCR	Coal combustion residuals
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
CWIP	Construction work in progress
DOE	U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FFB	Federal Financing Bank
GAAP	Generally accepted accounting principles
Gulf Power	Gulf Power Company
IRS	Internal Revenue Service
ITC	Investment tax credit
KWH	Kilowatt-hour
LIBOR	London Interbank Offered Rate
Mississippi Power	Mississippi Power Company
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MW	Megawatt
NCCR	Nuclear Construction Cost Recovery
NRC	U.S. Nuclear Regulatory Commission
OCI	Other comprehensive income
Plant Vogtle Units 3 and 4	Two new nuclear generating units under construction at Plant Vogtle
power pool	The operating arrangement whereby the integrated generating resources of the traditional operating companies and Southern Power Company are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power purchase agreement
PSC	Public Service Commission
ROE	Return on equity
S&P	Standard and Poor's Rating Services, a division of The McGraw Hill Companies, Inc.
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	U.S. Securities and Exchange Commission
SEGCO	Southern Electric Generating Company
Southern Company system	The Southern Company, the traditional operating companies, Southern Power, SEGCO, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
traditional operating companies	Alabama Power, Georgia Power Company, Gulf Power, and Mississippi Power

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Georgia Power Company 2014 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, 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 Plant Vogtle Units 3 and 4 and will own a 45.7% interest in these two nuclear generating units 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.

In December 2013, the Georgia PSC approved the 2013 ARP for the years 2014 through 2016 including a base rate increase of approximately $110 million for 2014 and required compliance filings for both 2015 and 2016 to review base rate increases for those respective years. On February 19, 2015, the Georgia PSC completed its review of the Company's October 3, 2014 compliance filing for 2015 and approved a base rate increase of approximately $136 million for that year. The 2016 base rate increase, which was approved in the 2013 ARP, will be determined through a compliance filing expected to be filed in late 2015, and will be subject to review by the Georgia PSC. The Company is scheduled to file its next base rate case by July 1, 2016. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Rate Plans" herein for additional information.

Key Performance Indicators

The Company continues to focus on several key performance indicators, including 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 to evaluate the Company's results and generally targets the top quartile of these surveys in measuring performance, which the Company achieved during 2014.

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 Company's 2014 Peak Season EFOR of 1.93% was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages, with performance targets set based on historical performance. The Company's 2014 performance was better than the target for these transmission and distribution reliability measures.

The Company uses net income after dividends on preferred and preference stock as the primary measure of the Company's financial performance. In 2014, the Company achieved its targeted net income after dividends on preferred and preference stock. See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance.

Earnings

The Company's 2014 net income after dividends on preferred and preference stock was $1.2 billion, representing a $51 million, or 4.3%, increase over the previous year. The increase was due primarily to an increase in base retail revenues effective January 1, 2014 as authorized under the 2013 ARP and colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013, partially offset by higher non-fuel operations and maintenance expenses.

The Company's 2013 net income after dividends on preferred and preference stock was $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.

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

	Amount	Increase (Decrease) from Prior Year	
	2014	**2014**	2013
		(in millions)	
Operating revenues	**$ 8,988**	**$ 714**	$ 276
Fuel	**2,547**	**240**	256
Purchased power	**988**	**104**	(97)
Other operations and maintenance	**1,902**	**248**	10
Depreciation and amortization	**846**	**39**	62
Taxes other than income taxes	**409**	**27**	8
Total operating expenses	**6,692**	**658**	239
Operating income	**2,296**	**56**	37
Allowance for equity funds used during construction	**45**	**15**	(23)
Interest expense, net of amounts capitalized	**348**	**(13)**	(5)
Other income (expense), net	**(22)**	**(27)**	22
Income taxes	**729**	**6**	35
Net income	**1,242**	**51**	6
Dividends on preferred and preference stock	**17**	**—**	—
Net income after dividends on preferred and preference stock	**$ 1,225**	**$ 51**	$ 6

Operating Revenues

Operating revenues for 2014 were $9.0 billion, reflecting a $714 million increase from 2013. Details of operating revenues were as follows:

	Amount	
	2014	2013
	(in millions)	
Retail — prior year	**$ 7,620**	$ 7,362
Estimated change resulting from —		
Rates and pricing	**183**	137
Sales growth (decline)	**21**	(5)
Weather	**139**	(61)
Fuel cost recovery	**277**	187
Retail — current year	**8,240**	7,620
Wholesale revenues —		
Non-affiliates	**335**	281
Affiliates	**42**	20
Total wholesale revenues	**377**	301
Other operating revenues	**371**	353
Total operating revenues	**$ 8,988**	$ 8,274
Percent change	**8.6%**	3.5%

Retail base revenues of $5.2 billion in 2014 increased $343 million, or 7.1%, compared to 2013. The significant factors driving this change are shown in the preceding table. The increase in rates and pricing was primarily due to base tariff increases effective January 1, 2014, as approved by the Georgia PSC in the 2013 ARP, and increases in collections for financing costs related to the construction of Plant Vogtle Units 3 and 4 through the NCCR tariff as well as higher contributions from market-driven rates from commercial and industrial customers. In 2014, residential base revenues increased $163 million, or 7.6%, commercial base revenues increased $108 million, or 5.5%, and industrial base revenues increased $74 million, or 11.1%, compared to 2013.

Retail base revenues of $4.9 billion in 2013 increased $71 million, or 1.5%, compared to 2012. The significant factors driving this change are shown in the preceding table. The increase in rates and pricing was 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 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 continued to be impacted by economic uncertainty, modest economic growth, and energy efficiency efforts.

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. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" herein for additional information.

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

	2014	2013	2012
		(in millions)	
Capacity and other	**$ 164**	$ 174	$ 177
Energy	**171**	107	104
Total non-affiliated	**$ 335**	$ 281	$ 281

Wholesale capacity revenues from PPAs are recognized either on a levelized basis over the appropriate contract period or the amounts billable under the contract terms and provide for 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.

Wholesale revenues from other non-affiliated sales increased $54 million, or 19.2%, in 2014 and were flat in 2013 as compared to 2012. The increase in 2014 was primarily due to increased demand resulting from colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013 and the lower cost of Company-owned generation compared to the market cost of available energy. The decrease in capacity revenues reflects the expiration of a wholesale contract in December 2013 and the removal of Plant Branch Unit 2 capacity from contracts following the unit's retirement in September 2013.

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 FERC. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost. In 2014, wholesale revenues from sales to affiliates increased $22 million as compared to 2013 due to colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013 and the lower cost of Company-owned generation. Wholesale revenues from sales to affiliated companies remained flat in 2013 as compared to 2012.

Other operating revenues increased $18 million, or 5.1%, in 2014 from the prior year primarily due to $7 million in transmission service revenues, $5 million of solar application fee revenues, and $5 million in outdoor lighting revenues. 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.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2014 and the percent change from the prior year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2014	**2014**	2013	**2014**	**2013***
	(in billions)				
Residential	**27.1**	**6.5%**	(1.0)%	**0.5%**	0.1%
Commercial	**32.4**	**1.4**	(0.9)	**(0.2)**	(0.2)
Industrial	**23.6**	**2.0**	—	**1.5**	0.7
Other	**0.7**	**0.5**	(1.8)	**0.3**	(1.8)
Total retail	**83.8**	**3.2**	(0.7)	**0.5%**	0.1%
Wholesale					
Non-affiliates	**4.3**	**42.6**	3.3		
Affiliates	**1.1**	**125.4**	(17.4)		
Total wholesale	**5.4**	**54.2**	(0.2)		
Total energy sales	**89.2**	**5.3%**	(0.7)%		

* 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 2013 weather-adjusted commercial KWH sales increased 0.2% as compared to 2012.

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

In 2014, KWH sales for residential and commercial customer classes increased compared to 2013 primarily due to colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013 and customer growth, partially offset by decreased customer usage. Industrial sales increased in 2014 compared to 2013. Increased demand in the paper, textiles, and stone, clay, and glass sectors were the main contributors to the increase in industrial sales in 2014 compared to 2013. Weather adjusted commercial KWH sales decreased by 0.2% as a result of decreased customer usage, largely offset by customer growth. Weather adjusted residential KWH sales increased by 0.5% as a result of customer growth, largely offset by decreased customer usage. Household income, one of the primary drivers of residential customer usage, was flat in 2014.

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 2013 compared to 2012.

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:

	2014	2013	2012
Total generation *(billions of KWHs)*	**69.9**	66.8	59.8
Total purchased power *(billions of KWHs)*	**23.1**	21.4	28.7
Sources of generation *(percent)* —			
Coal	**41**	35	39
Nuclear	**22**	23	27
Gas	**35**	39	33
Hydro	**2**	3	1
Cost of fuel, generated *(cents per net KWH)* —			
Coal	**4.52**	4.92	4.63
Nuclear	**0.90**	0.91	0.87
Gas	**3.67**	3.33	3.02
Average cost of fuel, generated *(cents per net KWH)*	**3.40**	3.32	3.07
Average cost of purchased power *(cents per net KWH)**	**5.20**	4.83	4.24

* 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 $3.5 billion in 2014, an increase of $344 million, or 10.8%, compared to 2013. The increase was primarily due to a $292 million increase in the volume of KWHs generated and purchased due to colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013 driving higher customer demand and an increase of $84 million in the average cost of purchased power primarily due to higher natural gas prices, partially offset by a $32 million decrease in the average cost of fuel primarily due to lower coal prices.

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 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 – "Retail Regulatory Matters – Fuel Cost Recovery" herein for additional information.

Fuel

Fuel expense was $2.5 billion in 2014, an increase of $240 million, or 10.4%, compared to 2013. The increase was primarily due to an increase of 5.7% in the volume of KWHs generated as a result of colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013 driving higher customer demand and a 2.4% increase in the average cost of fuel per KWH generated primarily due to higher natural gas prices, partially offset by lower coal prices. 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.

Purchased Power - Non-Affiliates

Purchased power expense from non-affiliates was $287 million in 2014, an increase of $63 million, or 28.1%, compared to 2013. The increase was primarily due to a 6.1% increase in the average cost per KWH purchased primarily resulting from higher natural gas prices and a 22.0% increase in the volume of KWHs purchased to meet higher customer demand resulting from colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013. 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.

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 $701 million in 2014, an increase of $41 million, or 6.2%, compared to 2013. The increase was primarily due to an increase of 5.8% in the average cost per KWH purchased reflecting higher natural gas prices and a 5.6% increase in the volume of KWHs purchased to meet higher customer demand resulting from colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013. 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.

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 2014, other operations and maintenance expenses increased $248 million, or 15.0%, compared to 2013. The increase was primarily due to increases of $74 million in transmission and distribution overhead line maintenance expenses, $58 million in generation expense to meet higher demand, $52 million in scheduled outage-related costs, $35 million in customer assistance expenses related to customer incentive and demand-side management costs, and $11 million in the storm damage accrual as authorized in the 2013 ARP.

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.

Depreciation and Amortization

Depreciation and amortization increased $39 million, or 4.8%, in 2014 compared to 2013. The increase was primarily due to decreases of $36 million and $17 million in amortization of regulatory liabilities related to state income tax credits that was completed in December 2013 and other cost of removal obligations as authorized in the 2013 ARP, respectively, partially offset by a decrease of $14 million in depreciation and amortization also as authorized in the 2013 ARP.

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 2012 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 "Depreciation and Amortization" for additional information.

Taxes Other Than Income Taxes

In 2014, taxes other than income taxes increased $27 million, or 7.1%, compared to 2013. The increase was primarily due to increases of $24 million in municipal franchise fees related to higher retail revenues and $9 million in payroll taxes, partially offset by a $6 million decrease in property 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.

Allowance for Equity Funds Used During Construction

AFUDC equity increased $15 million, or 50.0%, in 2014 compared to the prior year primarily due to an increase in construction related to ongoing environmental and transmission projects. 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 2012.

Interest Expense, Net of Amounts Capitalized

In 2014, interest expense, net of amounts capitalized decreased $13 million, or 3.6%, from the prior year. The decrease was primarily due to a $40 million decrease in interest on long-term debt resulting from redemptions and refinancing of long-term debt at lower interest rates and a $4 million increase in interest capitalized as a result of increased construction activity, partially offset by a $32 million increase in interest on outstanding long-term debt borrowings from the FFB.

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.

Other Income (Expense), net

In 2014, other income (expense), net decreased $27 million from the prior year primarily due to a $9 million increase in donations and an $8 million decrease in wholesale operating fee revenue. 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 fee revenue and a $9 million decrease in donations.

Income Taxes

Income taxes increased $6 million, or 0.8%, in 2014 compared to the prior year primarily due to higher pre-tax earnings and an increase in non-deductible book depreciation, partially offset by the recognition of tax benefits related to emission allowances and state apportionment, an increase in non-taxable AFUDC equity, and state income tax credits.

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.

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 completion and subsequent operation of ongoing construction projects, primarily Plant Vogtle Units 3 and 4. Future earnings in the near term will depend, in part, upon maintaining and growing sales which are subject to a number of factors. These factors include weather, competition, new energy contracts with other utilities, energy conservation practiced by customers, the use of alternative energy sources 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 may impact sales for the Company, as the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. 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 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. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. See Note 3 to the financial statements under "Environmental Matters – New Source Review Actions" for additional information. The ultimate outcome of these matters 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 2014, the Company had invested approximately $4.7 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $0.4 billion, $0.3 billion, and $0.2 billion for 2014, 2013, and 2012, respectively. The Company expects that capital expenditures to comply with environmental statutes and regulations will total approximately $0.8 billion from 2015 through 2017, with annual totals of approximately $0.3 billion, $0.2 billion, and $0.2 billion for 2015, 2016, and 2017, respectively. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" 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, closure and monitoring of CCR facilities, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time. See "Retail Regulatory Matters – Integrated Resource Plans" herein for additional information on planned unit retirements and fuel conversions.

Compliance with any new federal or state legislation or regulations relating to air quality, water, CCR, 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 $4.3 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.

In 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 up to April 16, 2016 for affected units for which extensions have been granted. On November 25, 2014, the U.S. Supreme Court granted a petition for review of the final MATS rule.

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 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 an ozone nonattainment area is a 15-county area within metropolitan Atlanta. On December 17, 2014, the EPA published a proposed rule to further reduce the current eight-hour ozone standard. The EPA is required by federal court order to complete this rulemaking by October 1, 2015. Finalization of a lower eight-hour ozone standard could result in the designation of new ozone nonattainment areas within the Company's service territory.

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, with the exception of the Atlanta area, the EPA has officially redesignated former nonattainment areas within the service territory as attainment for these standards. A redesignation request for the Atlanta area is pending with the EPA. In 2012, the EPA issued a final rule that increases the stringency of the annual fine particulate matter standard. The EPA promulgated final designations for the 2012 annual standard on December 18, 2014, and no new nonattainment areas were designated within the Company's service territory. The EPA has, however, deferred designation decisions for certain areas in Georgia, so future nonattainment designations in these areas are possible.

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 has announced plans to make additional designation decisions for SO_2 in the future, which could result in nonattainment designations for 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 Cross State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide emissions from power plants in 28 states in two phases, with Phase I beginning in 2015 and Phase II beginning in 2017. In 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR in its entirety, but on April 29, 2014, the U.S. Supreme Court overturned that decision and remanded the case back to the U.S. Court of Appeals for the District of Columbia Circuit for further proceedings. The U.S. Court of Appeals for the District of Columbia Circuit granted the EPA's motion to lift the stay of the rule, and the first phase of CSAPR took effect on January 1, 2015.

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, including fossil fuel-fired generating facilities, 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 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.

In February 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 proposed to supplement the 2013 proposed rule on September 17, 2014, making it more stringent. The EPA has entered into a settlement agreement requiring it to finalize the proposed rule by May 22, 2015. The proposed rule would require states subject to the rule (including Georgia, Alabama, and Florida) to revise their SSM provisions within 18 months after issuance of the final rule.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the current and proposed environmental requirements discussed above. As part of this strategy, the Company has developed a compliance plan for the MATS rule which includes reliance on existing emission control technologies, the construction of baghouses to provide an additional level of control on the emissions of mercury and particulates from certain generating units, the use of additives or other injection technology, the use of additional natural gas capability, and unit retirements. Additionally, certain transmission system upgrades are required. The impacts of the eight-hour ozone, fine particulate matter and SO_2 NAAQS, CSAPR, 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 the proposed and final rules, the resolution of pending and future legal challenges, and/or 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.

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 nitrogen oxide 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, 2014, the Company had installed the required controls on 14 of its coal-fired generating units with two additional projects to be completed before the unit-specific installation deadlines.

Water Quality

The EPA's final rule establishing standards for reducing effects on fish and other aquatic life caused by new and existing cooling water intake structures at existing power plants and manufacturing facilities became effective on October 14, 2014. The effect of this final rule will depend on the results of additional studies and implementation of the rule by regulators based on site-specific factors. The ultimate impact of this rule will also depend on the outcome of ongoing legal challenges and cannot be determined at this time.

In June 2013, the EPA published a proposed rule which requested comments on a range of potential regulatory options for addressing revised technology-based limits for certain wastestreams from steam electric power plants and best management practices for CCR surface impoundments. The EPA has entered into a consent decree requiring it to finalize revisions to the steam electric effluent guidelines by September 30, 2015. The ultimate impact of the rule will also depend on the specific technology requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time.

On April 21, 2014, the EPA and the U.S. Army Corps of Engineers jointly published a proposed rule to revise the regulatory definition of waters of the U.S. for all Clean Water Act (CWA) programs, which would significantly expand the scope of federal jurisdiction under the CWA. In addition, the rule as proposed could have significant impacts on economic development projects which could affect customer demand growth. The ultimate impact of the proposed rule will depend on the specific requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time. If finalized as proposed, this rule could significantly increase permitting and regulatory requirements and costs associated with the siting of new facilities and the installation, expansion, and maintenance of transmission and distribution lines.

These proposed and final water quality 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.

Coal Combustion Residuals

The Company currently manages CCR at onsite units consisting of landfills and surface impoundments (CCR Units) at 11 electric generating plants. In addition to on-site storage, the Company also sells a portion of its CCR to third parties for beneficial reuse. Individual states regulate CCR and the State of Georgia has its own regulatory requirements. The Company has an inspection program in place to assist in maintaining the integrity of its coal ash surface impoundments.

On December 19, 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), but has not yet published it in the Federal Register. The CCR Rule will regulate the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in CCR Units at active generating power plants. The CCR Rule does not mandate closure of CCR Units, but includes minimum criteria for active and inactive surface impoundments containing CCR and liquids, lateral expansions of existing units, and active landfills. Failure to meet the minimum criteria can result in the mandated closure of a CCR Unit. Although the EPA does not require individual states to adopt the final criteria, states have the option to incorporate the federal criteria into their state solid waste management plans in order to regulate CCR in a manner consistent with federal standards. The EPA's final rule continues to exclude the beneficial use of CCR from regulation.

The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the Company's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. The cost and timing of potential ash pond closure and ongoing monitoring activities that may be required in connection with the CCR Rule is also uncertain; however, the Company has developed a preliminary nominal dollar estimate of costs associated with closure and groundwater monitoring of ash ponds in place of approximately $390 million and ongoing post-closure care of approximately $62 million. The Company has previously recorded asset retirement obligations (ARO) associated with ash ponds of $500 million, or $458 million on a nominal dollar basis, based on existing state requirements. During 2015, the Company will record AROs for any incremental estimated closure costs resulting from acceleration in the timing of any currently planned closures and for differences between existing state requirements and the requirements of the CCR Rule. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

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

In 2014, the EPA published three sets of proposed standards that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. On January 8, 2014, the EPA published proposed standards for new units, and, on June 18, 2014, the EPA published proposed standards governing existing units, known as the Clean Power Plan, and separate standards governing CO_2 emissions from modified and reconstructed units. The EPA's proposed Clean Power Plan establishes guidelines for states to develop plans to address CO_2 emissions from existing fossil fuel-fired electric generating units. The EPA's proposed guidelines establish state-specific interim and final CO_2 emission rate goals to be achieved between 2020 and 2029 and in 2030 and thereafter. The proposed guidelines and standards could result in operational restrictions and material compliance costs, including capital expenditures, which could affect future unit retirement and replacement decisions. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

The Southern Company system filed comments on the EPA's proposed Clean Power Plan on December 1, 2014. These comments addressed legal and technical issues in addition to providing a preliminary estimated cost of complying with the proposed guidelines utilizing one of the EPA's compliance scenarios. Costs associated with this proposal could be significant to the utility industry and the Southern Company system. However, the ultimate financial and operational impact of the proposed Clean Power Plan on the Southern Company system cannot be determined at this time and will depend upon numerous known and unknown factors. Some of the unknown factors include: the structure, timing, and content of the EPA's final guidelines; individual state implementation of these guidelines, including the potential that state plans impose different standards; additional rulemaking activities in response to legal challenges and related court decisions; the impact of future changes in generation and emissions-related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement capacity; and the time periods over which compliance will be required.

Over the past several years, the U.S. Congress has also 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.

The EPA's greenhouse gas reporting rule requires annual reporting of CO_2 equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2013 greenhouse gas emissions were approximately 33 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2014 greenhouse gas emissions on the same basis is approximately 38 million metric tons of CO_2 equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation, the mix of fuel sources, and other factors.

Retail Regulatory Matters

The Company's revenues from regulated retail operations are collected through various rate mechanisms subject to the oversight of the Georgia PSC. The Company currently recovers its costs from the regulated retail business through the 2013 ARP, which includes traditional base tariff rates, Demand-Side Management (DSM) tariffs, ECCR tariffs, and Municipal Franchise Fee (MFF) tariffs. In addition, financing costs related to the construction of Plant Vogtle Units 3 and 4 are being collected through the NCCR tariff and fuel costs are collected through separate fuel cost recovery tariffs. See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.

Rate Plans

In December 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 in November 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 approximately $25 million; (3) DSM tariffs by approximately $1 million; and (4) MFF tariff by approximately $4 million, for a total increase in base revenues of approximately $110 million.

On February 19, 2015, in accordance with the 2013 ARP, the Georgia PSC approved adjustments to traditional base, ECCR, DSM, and MFF tariffs effective January 1, 2015 as follows:

- Traditional base tariffs by approximately $107 million to cover additional capacity costs;
- ECCR tariff by approximately $23 million;
- DSM tariffs by approximately $3 million; and
- MFF tariff by approximately $3 million to reflect the adjustments above.

The sum of these adjustments resulted in a base revenue increase of approximately $136 million in 2015.

The 2016 base rate increase, which was approved in the 2013 ARP, will be determined through a compliance filing expected to be filed in late 2015, and will be subject to review by the Georgia PSC.

Under the 2013 ARP, the Company's retail 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. In 2014, the Company's retail ROE exceeded 12.00%, and the Company expects to refund to retail customers approximately $13 million in 2015, subject to review and approval by the Georgia PSC.

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.

Renewables Development

On May 20, 2014, the Georgia PSC approved the Company's application for the certification of two PPAs executed in April 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.

On December 16, 2014, the Georgia PSC approved and certified ten PPAs that were executed in October 2014. These PPAs provide for the purchase of energy from 515 MWs of solar capacity as part of the Georgia Power Advanced Solar Initiative program, of which approximately 99 MWs is expected to be purchased from solar facilities owned by Southern Power. These PPAs are expected to commence in December 2015 and 2016 and have terms ranging from 20 to 30 years.

On October 23, 2014, the Georgia PSC approved the Company's request to build, own, and operate three 30-MW solar generation facilities at three U.S. Army bases by the end of 2016. In addition, on December 16, 2014, the Georgia PSC approved the Company's request to build, own, and operate a 30-MW solar generation facility at Kings Bay Naval facility by the end of 2016.

Integrated Resource Plans

See "Environmental Matters – Environmental Statutes and Regulations – Air Quality," "– Water Quality," "– Coal Combustion Residuals," and "– Global Climate Issues," 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 regulations of CCR and CO_2; the State of Georgia's Multi-

Pollutant Rule; and 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.

In July 2013, the Georgia PSC approved the Company's latest triennial Integrated Resource Plan (2013 IRP) including 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.

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 (250 MWs) was extended from December 31, 2013 as specified in the final order in the 2011 Integrated Resource Plan Update (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) were 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 in September 2013 to allow for necessary transmission system reliability improvements. In July 2013, the Georgia PSC approved the switch to natural gas as the primary fuel for Plant Yates Units 6 and 7. In September 2013, Plant Branch Unit 2 (319 MWs) was retired as approved by the Georgia PSC in the 2011 IRP Update in order to comply with the State of Georgia's Multi-Pollutant Rule.

In the 2013 ARP, the Georgia PSC approved the amortization of the 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.

On July 1, 2014, the Georgia PSC approved the Company's request to cancel the proposed biomass fuel conversion of Plant Mitchell Unit 3 (155 MWs) because it would not be cost effective for customers. The Company expects to request decertification of Plant Mitchell Unit 3 in connection with the triennial Integrated Resource Plan to be filed in 2016. The Company plans to continue to operate the unit as needed until the MATS rule becomes effective in April 2015.

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.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. 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. On January 20, 2015, the Georgia PSC approved the deferral of the Company's next fuel case filing until at least June 30, 2015.

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, Vogtle Owners), entered into an agreement with a consortium consisting of Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc., a subsidiary of The Shaw Group Inc., which was acquired by Chicago Bridge & Iron Company N.V. (CB&I) (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 Vogtle 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. The Vogtle 3 and 4 Agreement also provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees. The Contractor's liability to the Vogtle Owners for schedule and performance liquidated damages and warranty claims is subject to a cap. In addition, the Vogtle 3 and 4 Agreement provides for limited cost sharing by the Vogtle Owners for Contractor costs under certain conditions (which have not occurred), with maximum additional capital costs under this provision attributable to the Company (based on the Company's ownership interest) of approximately $114 million. Each Vogtle 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%.

Certain payment obligations of Westinghouse and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and CB&I's The Shaw Group Inc., respectively. In the event of certain credit rating downgrades of any Vogtle Owner, such Vogtle Owner will be required to provide a letter of credit or other credit enhancement. The Vogtle Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Vogtle Owners will be required to pay certain termination costs. The Contractor may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including certain Vogtle 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 Vogtle Owners, Vogtle 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, in late 2011, and issued combined construction and operating licenses (COLs) in early 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. On December 16, 2014, the Georgia PSC approved an increase to the NCCR tariff of approximately $27 million effective January 1, 2015.

In 2012, the Vogtle 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 Vogtle Owners are responsible for these costs under the terms of the Vogtle 3 and 4 Agreement. Also in 2012, the Company and the other Vogtle Owners filed suit against the Contractor in the U.S. District Court for the Southern District of Georgia seeking a declaratory judgment that the Vogtle Owners are not responsible for these costs. In 2012, the Contractor also filed suit against the Company and the other Vogtle Owners in the U.S. District Court for the District of Columbia alleging the Vogtle Owners are responsible for these costs. In August 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 in September 2013. The portion of additional costs claimed by the Contractor in its initial complaint that would be attributable to the Company (based on the Company's ownership interest) is approximately $425 million (in 2008 dollars). The Contractor also asserted it is entitled to extensions of the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. On May 22, 2014, the Contractor filed an amended counterclaim to the suit pending in the U.S. District Court for the Southern District of Georgia alleging that (i) the design changes to the DCD imposed by the NRC delayed module production and the impacts to the Contractor are recoverable by the Contractor under the Vogtle 3 and 4 Agreement and (ii) the changes to the basemat rebar design required by the NRC caused additional costs and delays recoverable by the Contractor under the Vogtle 3 and 4 Agreement. The Contractor did not specify in its amended counterclaim the amounts relating to these new allegations; however, the Contractor has subsequently asserted related minimum damages (based on the Company's ownership interest) of $113 million. The Contractor may from time to time continue to assert that it is entitled to additional payments with respect to these allegations, any of which could be substantial. The Company has not agreed to the proposed cost or to any changes to the guaranteed substantial completion dates or that the Vogtle Owners have any responsibility for costs related to these issues. Litigation is ongoing and the Company intends to vigorously defend the positions of the Vogtle Owners. 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.

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. The Company's eighth VCM report filed in February 2013 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.

In September 2013, the Georgia PSC approved a stipulation (2013 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 completion 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 be included in rate base, provided the Company shows the costs to be reasonable and prudent. In addition, financing costs on any construction-related costs in excess of the certified amount likely would be subject to recovery through AFUDC instead of the NCCR tariff.

The Georgia PSC has approved eleven VCM reports covering the periods through June 30, 2014, including construction capital costs incurred, which through that date totaled $2.8 billion.

On January 29, 2015, the Company announced that it was notified by the Contractor of the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4, which would incrementally delay the previously disclosed estimated in-service dates by 18 months (from the fourth quarter of 2017 to the second quarter of 2019 for Unit 3 and from the fourth quarter of 2018 to the second quarter of 2020 for Unit 4). The Company has not agreed to any changes to the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. The Company does not believe that the Contractor's revised forecast reflects all efforts that may be possible to mitigate the Contractor's delay.

In addition, the Company believes that, pursuant to the Vogtle 3 and 4 Agreement, the Contractor is responsible for the Contractor's costs related to the Contractor's delay (including any related construction and mitigation costs, which could be material) and that the Vogtle Owners are entitled to recover liquidated damages for the Contractor's delay beyond the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. Consistent with the Contractor's position in the pending litigation described above, the Company expects the Contractor to contest any claims for liquidated damages and to assert that the Vogtle Owners are responsible for additional costs related to the Contractor's delay.

On February 27, 2015, the Company filed its twelfth VCM report with the Georgia PSC covering the period from July 1 through December 31, 2014, which requests approval for an additional $0.2 billion of construction capital costs incurred during that period and reflects the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4 as well as additional estimated owner-related costs of approximately $10 million per month expected to result from the Contractor's proposed 18-month delay, including property taxes, oversight costs, compliance costs, and other operational readiness costs. No Contractor costs related to the Contractor's proposed 18-month delay are included in the twelfth VCM report. Additionally, while the Company has not agreed to any change to the guaranteed substantial completion dates, the twelfth VCM report includes a requested amendment to the Plant Vogtle Units 3 and 4 certificate to reflect the Contractor's revised forecast, to include the estimated owner's costs associated with the proposed 18-month Contractor delay, and to increase the estimated total in-service capital cost of Plant Vogtle Units 3 and 4 to $5.0 billion.

The Company will continue to incur financing costs of approximately $30 million per month until Plant Vogtle Units 3 and 4 are placed in service. The twelfth VCM report estimates total associated financing costs during the construction period to be approximately $2.5 billion.

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 Vogtle Owners or the Contractor or to both.

As construction continues, the risk remains that ongoing challenges with Contractor performance including additional challenges in its fabrication, assembly, delivery, and installation of the shield building and 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. In addition, the IRS allocated production tax credits to each of Plant Vogtle Units 3 and 4, which require the applicable unit to be placed in service before 2021.

Additional claims by the Contractor or the Company (on behalf of the Vogtle 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 December 19, 2014, the Tax Increase Prevention Act of 2014 (TIPA) was signed into law. The TIPA retroactively extended several tax credits through 2014 and extended 50% bonus depreciation for property placed in service in 2014 (and for certain long-term production-period projects to be placed in service in 2015). The extension of 50% bonus depreciation had a positive impact on the Company's cash flows and, combined with bonus depreciation allowed in 2014 under the American Taxpayer Relief Act of 2012, resulted in approximately $200 million of positive cash flows for the 2014 tax year. The estimated cash flow benefit of bonus depreciation related to TIPA is expected to be approximately $45 million to $50 million for the 2015 tax year.

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 occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters.

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.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

The Company is subject to retail regulation by the 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, AROs, 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 position, results of operations, or cash flows.

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.

For purposes of its December 31, 2014 measurement date, the Company adopted new mortality tables for its pension plans and retiree life and medical plans, which reflect increased life expectancies in the U.S. The adoption of new mortality tables increased the projected benefit obligations for the Company's pension plans and other postretirement benefit plans by approximately $226 million and $46 million, respectively. The adoption of new mortality tables will increase net periodic costs related to the Company's pension plans and other postretirement benefit plans in 2015 by $30 million and $5 million, respectively.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in an $11 million or less change in total annual benefit expense and a $163 million or less change in projected obligations.

Recently Issued Accounting Standards

On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2014. 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 2015 through 2017, 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, to add or change fuel sources for certain existing 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, as well as by accessing borrowings from financial institutions and borrowings through the FFB. 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, 2014 as compared to December 31, 2013. On December 18, 2014, the Company voluntarily contributed $150 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2015. The Company funded approximately $2 million to its nuclear decommissioning trust funds in 2014. See "Contractual Obligations" herein and Notes 1 and 2 to the financial statements under "Nuclear Decommissioning" and "Pension Plans," respectively, for additional information.

Net cash provided from operating activities totaled $2.4 billion in 2014, a decrease of $403 million from 2013, primarily due to fuel cost recovery and storm restoration costs, partially offset by higher retail operating revenues and lower fuel inventory additions. 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 used for investing activities totaled $2.2 billion, $1.9 billion, and $2.0 billion in 2014, 2013, and 2012, 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. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Nuclear Construction" herein for additional information.

Net cash used for financing activities totaled $163 million, $891 million, and $290 million for 2014, 2013, and 2012, respectively. The decrease in cash used in 2014 compared to 2013 was primarily due to borrowings from the FFB for construction of Plant Vogtle Units 3 and 4, partially offset by FFB loan issuance costs and a reduction in short-term debt. 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. 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 2014 included an increase of $1.2 billion in total property, plant, and equipment due to gross property additions described above, an increase in other regulatory assets, deferred of $640 million, a decrease of $303 million in fossil fuel stock due to an increase in fuel generation, and an increase of $361 million in employee benefit obligations primarily as a result of changes in the actuarial assumptions. See Note 2 to the financial statements for additional information.

The Company's ratio of common equity to total capitalization, including short-term debt, was 50.4% in 2014 and 49.1% in 2013. 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 FFB. The Company is obligated to reimburse the DOE for any payments the DOE is required to make to the FFB under the guarantee. The Company's reimbursement obligations to the DOE are full recourse and also are secured by a first priority lien on (i) the Company's 45.7% ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor core) 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 under "DOE Loan Guarantee Borrowings" for additional information regarding the Loan Guarantee Agreement and Note 3 to the financial statements under "Retail Regulatory Matters – Nuclear Construction" for additional information regarding Plant Vogtle Units 3 and 4.

Eligible Project Costs incurred through December 31, 2014 would allow for borrowings of up to $2.1 billion under the FFB Credit Facility. Through December 31, 2014, the Company had borrowed $1.2 billion under the FFB Credit Facility, leaving $0.9 billion of currently available borrowing ability.

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 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.

As of December 31, 2014, the Company's current liabilities exceeded current assets by $1.0 billion primarily due to long-term debt that is due in one year. The Company intends to utilize equity contributions from Southern Company and cash from operations, as well as commercial paper, lines of credit, bank notes, and securities issuances, as market conditions permit, to fund the Company's short-term capital needs. In 2015, the Company also expects to utilize borrowings through the FFB as the primary source of borrowed funds. The Company has substantial cash flow from operating activities and access to the capital markets and financial institutions to meet short-term liquidity needs.

At December 31, 2014, the Company had approximately $24 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2014 were as follows:

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

(a) No credit arrangements expire in 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 program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2014 was approximately $865 million. In addition, at December 31, 2014, the Company had $118 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months. As of December 31, 2014, $98 million of certain pollution control revenue bonds of the Company were reclassified to securities due within one year in anticipation of their redemption in connection with unit retirement decisions.

The Company's credit 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 bank credit arrangements contain material adverse change clauses at the time of borrowings. Subject to applicable market conditions, 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		Short-term Debt During the Period [a]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2014:					
Commercial paper	**$ 156**	**0.3%**	**$ 280**	**0.2%**	**$703**
Short-term bank debt	**—**	**—%**	**56**	**0.9%**	**400**
Total	**$ 156**	**0.3%**	**$ 336**	**0.3%**	
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%	

(a) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2014, 2013, and 2012.

The Company believes the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, short-term bank notes, 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 June 2014, the Company redeemed $17 million aggregate principal amount of Development Authority of Bartow County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Bowen Project), Second Series 1998 and $19.5 million aggregate principal amount of Development Authority of Appling County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Hatch Project), Second Series 2001.

In July 2014, the Company reoffered to the public $40 million aggregate principal amount of Development Authority of Monroe County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Scherer Project), First Series 2009, which had been previously purchased and held by the Company since 2010.

DOE Loan Guarantee Borrowings

On February 20, 2014, the Company made initial borrowings under the FFB Credit Facility in an aggregate principal amount of $1.0 billion and on December 11, 2014, the Company made additional borrowings under the FFB Credit Facility in an aggregate principal amount of $200 million. 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 2044 and the interest rate applicable to the remaining $500 million is 3.488% for an interest period that extends to 2029 and is expected to be reset from time to time thereafter through 2044. The interest rate applicable to the $200 million advance in December 2014 is 3.002% for an interest period that extends to 2044. The final maturity date for all advances under the FFB Credit Facility is February 20, 2044. The proceeds of the borrowings in 2014 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. In connection with its entry into the agreements with the DOE and the FFB, the Company incurred issuance costs of approximately $66 million, which are being amortized over the life of the borrowings under the FFB Credit Facility.

Under the Loan Guarantee Agreement, the Company 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 engineering, procurement, and construction contract, as amended, relating to Plant Vogtle Units 3 and 4 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 the Company or Southern Nuclear to comply with requirements of law or DOE loan guarantee program requirements. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information.

Other

In February 2014, the Company repaid three four-month floating rate bank loans in an aggregate principal amount of $400 million. At December 31, 2014, the Company had no bank term loans outstanding.

In October 2014, the Company entered into interest rate swaps to hedge exposure to interest rate changes related to existing debt. The notional amount of the swaps totaled $900 million.

In November and December 2014, the Company entered into forward-starting interest rate swaps to hedge exposure to interest rate changes related to anticipated borrowings under the FFB Credit Facility in 2015. The notional amount of the swaps totaled $700 million.

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, interest rate derivatives, and construction of new generation. The maximum potential collateral requirements under these contracts at December 31, 2014 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB- and/or Baa3	$ 85
Below BBB- and/or Baa3	1,332

Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market and the variable rate pollution control revenue bond market.

Market Price Risk

Due to cost-based rate regulation and other various cost recovery mechanisms, the Company continues to have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company may enter into derivatives designated as hedges. The weighted average interest rate on $1.3 billion of long-term variable interest rate exposure at January 1, 2015 was 1.24%. If the Company sustained a 100 basis point change in interest rates for all long-term variable interest rate exposure, the change would affect annualized interest expense by approximately $13 million at January 1, 2015. 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, 2014 when compared to the December 31, 2013 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:

	2014 Changes	2013 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (16)**	$ (34)
Contracts realized or settled:		
Swaps realized or settled	**2**	9
Options realized or settled	**8**	20
Current period changes[(a)]:		
Swaps	**(1)**	1
Options	**(13)**	(12)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (20)**	$ (16)

(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:

	2014	2013
	mmBtu Volume	
	(in millions)	
Commodity – Natural gas swaps	**4**	7
Commodity – Natural gas options	**42**	52
Total hedge volume	**46**	59

The weighted average swap contract cost above market prices was approximately $0.68 per mmBtu as of December 31, 2014 and $0.50 per mmBtu as of December 31, 2013. 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, 2014 and 2013, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and were related to the Company's fuel-hedging program, which have 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, 2014 were as follows:

	Fair Value Measurements December 31, 2014		
	Total	Maturity	
	Fair Value	Year 1	Years 2&3
	(in millions)		
Level 1	$ —	$ —	$ —
Level 2	(20)	(16)	(4)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$ (20)	$ (16)	$ (4)

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 and S&P or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements.

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to be $2.4 billion for 2015, $2.4 billion for 2016, and $2.1 billion for 2017. Capital expenditures to comply with environmental statutes and regulations included in these estimated amounts are $0.3 billion, $0.2 billion, and $0.2 billion for 2015, 2016, and 2017, respectively. These amounts include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units.

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 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 information regarding additional factors that may impact construction expenditures.

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

	2015	2016-2017	2018-2019	After 2019	Total
			(in millions)		
Long-term debt[(a)] —					
Principal	$ 1,148	$ 1,154	$ 750	$ 6,756	$ 9,808
Interest	342	634	557	5,128	6,661
Preferred and preference stock dividends[(b)]	17	35	35	—	87
Financial derivative obligations[(c)]	31	4	—	—	35
Operating leases[(d)]	25	36	15	14	90
Capital leases[(d)]	6	13	15	6	40
Purchase commitments —					
Capital[(e)]	2,165	4,150	—	—	6,315
Fuel[(f)]	1,805	2,176	1,371	8,722	14,074
Purchased power[(g)]	293	684	606	3,545	5,128
Other[(h)]	92	124	101	272	589
Trusts —					
Nuclear decommissioning[(i)]	5	11	11	110	137
Pension and other postretirement benefit plans[(j)]	44	82	—	—	126
Total	$ 5,973	$ 9,103	$ 3,461	$ 24,553	$ 43,090

(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, 2015, 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) Includes derivative liabilities related to cash flow hedges of forecasted debt, as well as energy-related derivatives. For additional information, see Notes 1 and 11 to the financial statements.
(d) Excludes PPAs that are accounted for as leases and 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, 2014, 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, 2014.
(g) Estimated minimum long-term obligations for various PPA purchases from gas-fired, biomass, and wind-powered facilities. A total of $1.1 billion of biomass PPAs is contingent upon the counterparties meeting specified contract dates for commercial operation and may change as a result of regulatory action. See FUTURE EARNINGS POTENTIAL – "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 for Plant Hatch and Plant Vogtle Units 1 and 2 are based on the 2013 ARP. 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 2014 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, access to sources of capital, projections for the qualified pension plan, postretirement benefit plan, and nuclear decommissioning trust fund contributions, financing activities, completion dates of construction projects, filings with state and federal regulatory authorities, impact of the TIPA, estimated sales and purchases under power sale and purchase agreements, and estimated construction and other plans and 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, CCR, and emissions of sulfur, nitrogen, CO_2, 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 pending EPA civil action against the Company and IRS 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 last recession, population and business growth (and declines), the effects of energy conservation and efficiency 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;
- the ability to control costs and avoid cost overruns during the development and construction of facilities, which include the development and construction of generating facilities with designs that have not been finalized or previously constructed, including changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Georgia PSC);
- the ability to construct facilities in accordance with the requirements of permits and licenses, to satisfy any operational and environmental performance standards, including any PSC requirements and the requirements of tax credits and other incentives, and to integrate facilities into the Southern Company system upon completion of construction;
- 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;
- the ability to successfully operate generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
- legal proceedings and regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals and NRC actions and related legal proceedings involving the commercial parties;
- 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 cyber intrusion or terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any 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 the 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 and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

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

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STATEMENTS OF INCOME
For the Years Ended December 31, 2014, 2013, and 2012
Georgia Power Company 2014 Annual Report

	2014	2013	2012
		(in millions)	
Operating Revenues:			
Retail revenues	**$ 8,240**	$ 7,620	$ 7,362
Wholesale revenues, non-affiliates	**335**	281	281
Wholesale revenues, affiliates	**42**	20	20
Other revenues	**371**	353	335
Total operating revenues	**8,988**	8,274	7,998
Operating Expenses:			
Fuel	**2,547**	2,307	2,051
Purchased power, non-affiliates	**287**	224	315
Purchased power, affiliates	**701**	660	666
Other operations and maintenance	**1,902**	1,654	1,644
Depreciation and amortization	**846**	807	745
Taxes other than income taxes	**409**	382	374
Total operating expenses	**6,692**	6,034	5,795
Operating Income	**2,296**	2,240	2,203
Other Income and (Expense):			
Allowance for equity funds used during construction	**45**	30	53
Interest expense, net of amounts capitalized	**(348)**	(361)	(366)
Other income (expense), net	**(22)**	5	(17)
Total other income and (expense)	**(325)**	(326)	(330)
Earnings Before Income Taxes	**1,971**	1,914	1,873
Income taxes	**729**	723	688
Net Income	**1,242**	1,191	1,185
Dividends on Preferred and Preference Stock	**17**	17	17
Net Income After Dividends on Preferred and Preference Stock	**$ 1,225**	$ 1,174	$ 1,168

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2014, 2013, and 2012
Georgia Power Company 2014 Annual Report

	2014	2013	2012
		(in millions)	
Net Income	**$ 1,242**	$ 1,191	$ 1,185
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(3), $-, and $-, respectively	**(5)**	—	—
Reclassification adjustment for amounts included in net income, net of tax of $1, $1, and $1, respectively	**2**	2	2
Total other comprehensive income (loss)	**(3)**	2	2
Comprehensive Income	**$ 1,239**	$ 1,193	$ 1,187

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2014, 2013, and 2012
Georgia Power Company 2014 Annual Report

	2014	2013	2012
		(in millions)	
Operating Activities:			
Net income	**$ 1,242**	$ 1,191	$ 1,185
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	**1,019**	979	912
Deferred income taxes	**352**	476	377
Allowance for equity funds used during construction	**(45)**	(30)	(53)
Retail fuel cost over recovery — long-term	**(44)**	(123)	123
Pension, postretirement, and other employee benefits	**19**	66	21
Pension and postretirement funding	**(156)**	(8)	(12)
Other, net	**39**	38	(12)
Changes in certain current assets and liabilities —			
-Receivables	**(248)**	(58)	205
-Fossil fuel stock	**303**	250	(269)
-Prepaid income taxes	**(216)**	(17)	(7)
-Other current assets	**(37)**	40	(53)
-Accounts payable	**16**	67	(165)
-Accrued taxes	**17**	(14)	(76)
-Accrued compensation	**62**	(37)	(18)
-Retail fuel cost over-recovery — short-term	**(14)**	(49)	107
-Other current liabilities	**54**	(5)	30
Net cash provided from operating activities	**2,363**	2,766	2,295
Investing Activities:			
Property additions	**(2,023)**	(1,743)	(1,723)
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	**(671)**	(706)	(852)
Nuclear decommissioning trust fund sales	**669**	705	850
Cost of removal, net of salvage	**(65)**	(59)	(82)
Change in construction payables, net of joint owner portion	**(54)**	(67)	(149)
Prepaid long-term service agreements	**(70)**	(18)	(34)
Other investing activities	**8**	(2)	17
Net cash used for investing activities	**(2,206)**	(1,890)	(1,973)
Financing Activities:			
Increase (decrease) in notes payable, net	**(891)**	1,047	(513)
Proceeds —			
Capital contributions from parent company	**549**	37	42
Pollution control revenue bonds issuances and remarketings	**40**	194	284
Senior notes issuances	**—**	850	2,300
FFB loan	**1,200**	—	—
Redemptions and repurchases —			
Pollution control revenue bonds	**(37)**	(298)	(284)
Senior notes	**—**	(1,775)	(850)
Other long-term debt	**—**	—	(250)
Payment of preferred and preference stock dividends	**(17)**	(17)	(17)
Payment of common stock dividends	**(954)**	(907)	(983)
FFB loan issuance costs	**(49)**	(5)	(3)
Other financing activities	**(4)**	(17)	(16)
Net cash used for financing activities	**(163)**	(891)	(290)
Net Change in Cash and Cash Equivalents	**(6)**	(15)	32
Cash and Cash Equivalents at Beginning of Year	**30**	45	13
Cash and Cash Equivalents at End of Year	**$ 24**	$ 30	$ 45
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $18, $14 and $21 capitalized, respectively)	**$ 319**	$ 344	$ 337
Income taxes (net of refunds)	**507**	298	312
Noncash transactions — accrued property additions at year-end	**154**	208	261

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

BALANCE SHEETS
At December 31, 2014 and 2013
Georgia Power Company 2014 Annual Report

Assets	2014	2013
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 24**	$ 30
Receivables —		
Customer accounts receivable	**553**	512
Unbilled revenues	**201**	209
Joint owner accounts receivable	**121**	67
Other accounts and notes receivable	**61**	117
Affiliated companies	**18**	21
Accumulated provision for uncollectible accounts	**(6)**	(5)
Fossil fuel stock, at average cost	**439**	742
Materials and supplies, at average cost	**438**	409
Vacation pay	**91**	88
Prepaid income taxes	**278**	97
Other regulatory assets, current	**136**	106
Other current assets	**74**	53
Total current assets	**2,428**	2,446
Property, Plant, and Equipment:		
In service	**31,083**	30,132
Less accumulated provision for depreciation	**11,222**	10,970
Plant in service, net of depreciation	**19,861**	19,162
Other utility plant, net	**211**	240
Nuclear fuel, at amortized cost	**563**	523
Construction work in progress	**4,031**	3,500
Total property, plant, and equipment	**24,666**	23,425
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**58**	46
Nuclear decommissioning trusts, at fair value	**789**	751
Miscellaneous property and investments	**38**	44
Total other property and investments	**885**	841
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**698**	718
Prepaid pension costs	**—**	118
Deferred under recovered regulatory clause revenues	**197**	—
Other regulatory assets, deferred	**1,753**	1,113
Other deferred charges and assets	**403**	246
Total deferred charges and other assets	**3,051**	2,195
Total Assets	**$ 31,030**	$ 28,907

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

BALANCE SHEETS
At December 31, 2014 and 2013
Georgia Power Company 2014 Annual Report

Liabilities and Stockholder's Equity	**2014**	2013
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 1,154**	$ 5
Notes payable	**156**	1,047
Accounts payable —		
Affiliated	**451**	417
Other	**555**	472
Customer deposits	**253**	246
Other accrued taxes	**332**	321
Accrued interest	**96**	91
Accrued vacation pay	**63**	61
Accrued compensation	**153**	80
Liabilities from risk management activities	**32**	13
Other regulatory liabilities, current	**21**	17
Over recovered regulatory clause revenues, current	**—**	14
Other current liabilities	**204**	122
Total current liabilities	**3,470**	2,906
Long-Term Debt (See accompanying statements)	**8,683**	8,633
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**5,507**	5,200
Deferred credits related to income taxes	**106**	112
Accumulated deferred investment tax credits	**196**	203
Employee benefit obligations	**903**	542
Asset retirement obligations	**1,223**	1,210
Other cost of removal obligations	**46**	43
Other deferred credits and liabilities	**209**	201
Total deferred credits and other liabilities	**8,190**	7,511
Total Liabilities	**20,343**	19,050
Preferred Stock (See accompanying statements)	**45**	45
Preference Stock (See accompanying statements)	**221**	221
Common Stockholder's Equity (See accompanying statements)	**10,421**	9,591
Total Liabilities and Stockholder's Equity	**$ 31,030**	$ 28,907
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2014 and 2013
Georgia Power Company 2014 Annual Report

	2014	2013	2014	2013
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable —				
Variable rates (0.56% to 0.63% at 1/1/15) due 2016	**450**	450		
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		
4.25% due 2019	**500**	500		
2.85% to 5.95% due 2022-2043	**3,975**	3,975		
Total long-term notes payable	**6,925**	6,925		
Other long-term debt —				
Pollution control revenue bonds:				
0.80% to 4.00% due 2022-2049	**818**	818		
Variable rates (0.03% to 0.04% at 1/1/15) due 2015	**98**	—		
Variable rate (0.04% at 1/1/15) due 2016	**4**	4		
Variable rate (0.04% at 1/1/14) due 2018	**—**	20		
Variable rates (0.01% to 0.09% at 1/1/15) due 2022-2052	**763**	838		
FFB loans (3.00% to 3.86%) due 2044	**1,200**	—		
Total other long-term debt	**2,883**	1,680		
Capitalized lease obligations	**40**	45		
Unamortized debt discount	**(11)**	(12)		
Total long-term debt (annual interest requirement — $342 million)	**9,837**	8,638		
Less amount due within one year	**1,154**	5		
Long-term debt excluding amount due within one year	**8,683**	8,633	**44.8%**	46.7%
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 — $17 million)	**266**	266	**1.4**	1.4
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized — 20,000,000 shares				
Outstanding — 9,261,500 shares	**398**	398		
Paid-in capital	**6,196**	5,633		
Retained earnings	**3,835**	3,565		
Accumulated other comprehensive loss	**(8)**	(5)		
Total common stockholder's equity	**10,421**	9,591	**53.8**	51.9
Total Capitalization	**$ 19,370**	$ 18,490	**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, 2014, 2013, and 2012
Georgia Power Company 2014 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, 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**
Net income after dividends on preferred and preference stock	**—**	**—**	**—**	**1,225**	**—**	**1,225**
Capital contributions from parent company	**—**	**—**	**563**	**—**	**—**	**563**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**(3)**	**(3)**
Cash dividends on common stock	**—**	**—**	**—**	**(954)**	**—**	**(954)**
Other	**—**	**—**	**—**	**(1)**	**—**	**(1)**
Balance at December 31, 2014	**9**	**$ 398**	**$ 6,196**	**$ 3,835**	**$ (8)**	**$ 10,421**

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, SCS, SouthernLINC Wireless, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, and other direct and indirect subsidiaries. The traditional operating companies – the Company, Alabama Power, Gulf Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail 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 FERC and the Georgia PSC. The Company follows 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.

Recently Issued Accounting Standards

On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

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 $555 million in 2014, $504 million in 2013, and $540 million in 2012. 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 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 $643 million in 2014, $555 million in 2013, and $574 million in 2012.

The Company has entered into several PPAs with Southern Power for capacity and energy. Expenses associated with these PPAs were $144 million, $136 million, and $147 million in 2014, 2013, and 2012, 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, 2014 and 2013. 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 $9 million in 2014, $10 million in 2013, and $7 million in 2012. 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 2014, 2013, or 2012.

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

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

	2014	2013	Note
	(in millions)		
Retiree benefit plans	**$ 1,325**	$ 691	(a, j)
Deferred income tax charges	**668**	684	(b, j)
Deferred income tax charges — Medicare subsidy	**34**	38	(c)
Loss on reacquired debt	**163**	181	(d, j)
Asset retirement obligations	**108**	137	(b, j)
Fuel-hedging (realized and unrealized) losses	**29**	22	(e, j)
Vacation pay	**91**	88	(f, j)
Building lease	**31**	37	(g, j)
Cancelled construction projects	**67**	70	(h)
Remaining net book value of retired units	**25**	28	(i)
Storm damage reserves	**98**	37	(c)
Other regulatory assets	**63**	49	(c)
Other cost of removal obligations	**(60)**	(58)	(b)
Deferred income tax credits	**(106)**	(112)	(b, j)
Other regulatory liabilities	**(7)**	(6)	(e, j)
Total regulatory assets (liabilities), net	**$ 2,529**	$ 1,886	

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 13 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, 2014, other cost of removal obligations included $29 million that will be amortized over the remaining two-year period of January 2015 through December 2016 in accordance with the Company's 2013 ARP.

(c) Recorded and recovered or amortized as approved by the Georgia PSC over periods generally not exceeding eight 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 38 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 life of the building through 2020.

(h) Costs associated with construction of environmental controls that will not be completed as a result of unit retirements are being amortized as approved by the Georgia PSC over periods not exceeding nine years or through 2022.

(i) Amortized as approved by the Georgia PSC over periods not exceeding 10 years or through 2022.

(j) Generally not earning a return as they are excluded from rate base or are 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 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 from PPAs are recognized either on a levelized basis over the appropriate contract period or the amount billable under the contract terms. 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 generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel. See Note 3 under "Retail Regulatory Matters – Nuclear Waste Fund Fee" 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 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:

	2014	2013
	(in millions)	
Generation	**$ 15,201**	$ 14,872
Transmission	**5,086**	4,859
Distribution	**8,913**	8,620
General	**1,855**	1,753
Plant acquisition adjustment	**28**	28
Total plant in service	**$ 31,083**	$ 30,132

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.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 2.7% in 2014, 3.0% in 2013, and 2.9% in 2012. Depreciation studies are conducted periodically to update the composite rates that are approved by the Georgia PSC and the FERC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

In 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 $14 million is being amortized annually over the three years ending December 31, 2016.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations (ARO) 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 ARO 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 AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability 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 AROs included in the balance sheets are as follows:

	2014	2013
	(in millions)	
Balance at beginning of year	**$ 1,222**	$ 1,105
Liabilities incurred	**9**	2
Liabilities settled	**(12)**	(13)
Accretion	**53**	55
Cash flow revisions	**(17)**	73
Balance at end of year	**$ 1,255**	$ 1,222

The 2014 decrease in cash flow revisions is primarily related to settled AROs for asbestos remediation. The 2013 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 AROs based on the latest decommissioning study.

On December 19, 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), but has not yet published it in the Federal Register. The CCR Rule will regulate the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in landfills and surface impoundments at active generating power plants. The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the Company's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. The cost and timing of potential ash pond closure and ongoing monitoring activities that may be required in connection with the CCR Rule is also uncertain; however, the Company has developed a preliminary nominal dollar estimate of costs associated with closure and groundwater monitoring of ash ponds in place of approximately $390 million and ongoing post-closure care of approximately $62 million. The Company has previously recorded AROs associated with ash ponds of $500 million, or $458 million on a nominal dollar basis, based on existing state requirements. During 2015, the Company will record AROs for any incremental estimated closure costs resulting from acceleration in the timing of any currently planned closures and for differences between existing state requirements and the requirements of the CCR Rule. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

Nuclear Decommissioning

The 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 IRS. While the Company is allowed to prescribe an overall investment policy to the Funds' managers, the Company and its affiliates are not allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the management of the Company. The Funds' managers are authorized, within certain investment guidelines, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

The Company records the investment securities held in the Funds at fair value, as disclosed in Note 10, as management believes that fair value best represents the nature of the Funds. Gains and losses, whether realized or unrealized, are recorded in the regulatory liability for AROs 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 loaned are fully collateralized by cash, letters of credit, and/or securities issued or guaranteed by the U.S. government or its agencies or instrumentalities. As of December 31, 2014 and 2013, approximately $51 million and $32 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 $52 million and $33 million at December 31, 2014 and 2013, 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, 2014, investment securities in the Funds totaled $789 million, consisting of equity securities of $303 million, debt securities of $475 million, and $11 million of other securities. 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. 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 $669 million, $705 million, and $850 million in 2014, 2013, and 2012, respectively, all of which were reinvested. For 2014, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $44 million, of which an immaterial amount related to unrealized gains and losses on securities held in the Funds at December 31, 2014. 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 losses on securities held in the Funds at December 31, 2012. 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 the securities 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, 2014 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	$ 496	$ 293

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. Under the 2013 ARP, the Georgia PSC approved annual decommissioning cost through 2016 for ratemaking of $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 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 2014, 2013, and 2012, the average AFUDC rates were 5.6%, 5.3%, and 6.8%, respectively, and AFUDC capitalized was $62 million, $44 million, and $75 million, respectively. AFUDC, net of income taxes, was 4.6%, 3.3%, and 5.7% of net income after dividends on preferred and preference stock for 2014, 2013, and 2012, respectively. See Note 3 under "Retail Regulatory Matters – Nuclear Construction" for additional information on the inclusion of construction costs related to 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. Beginning January 1, 2014, the Company is accruing $30 million annually under the 2013 ARP that is recoverable through base rates. As of December 31, 2014 and December 31, 2013, the balance in the regulatory asset related to storm damage was $98 million and $37 million, respectively, with approximately $30 million included in other regulatory assets, current for both years and approximately $68 million and $7 million included in other regulatory assets, deferred, respectively. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for storm damage costs. As a result of the regulatory treatment, costs related to storms are generally not expected to have a material impact on the Company's financial statements.

Environmental Remediation Recovery

The Company maintains a reserve for environmental remediation as mandated by the Georgia PSC. In December 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, 2014, the balance of the environmental remediation liability was $22 million, with approximately $2 million included in other regulatory assets, current and approximately $14 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 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 regarding fair value. 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. Derivative contracts that qualify as cash flow hedges of anticipated transactions or are recoverable through the Georgia PSC-approved fuel-hedging program result 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 that qualify as fair value hedges 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 regarding derivatives.

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, 2014.

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). In December 2014, the Company voluntarily contributed $150 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2015. 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, 2015, other postretirement trust contributions are expected to total approximately $17 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 2011 for the 2012 plan year using discount rates for the pension plans and the other postretirement benefit plans of 4.98% and 4.87%, respectively, and an annual salary increase of 3.84%.

	2014	2013	2012
Discount rate:			
Pension plans	**4.18%**	5.02%	4.27%
Other postretirement benefit plans	**4.03**	4.85	4.04
Annual salary increase	**3.59**	3.59	3.59
Long-term return on plan assets:			
Pension plans	**8.20**	8.20	8.20
Other postretirement benefit plans	**6.75**	6.74	7.24

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.

For purposes of its December 31, 2014 measurement date, the Company adopted new mortality tables for its pension plans and retiree life and medical plans, which reflect increased life expectancies in the U.S. The adoption of new mortality tables increased the projected benefit obligations for the Company's pension plans and other postretirement benefit plans by approximately $226 million and $46 million, respectively.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2014 were as follows:

	Initial Cost Trend Rate	**Ultimate Cost Trend Rate**	**Year That Ultimate Rate is Reached**
Pre-65	9.00%	4.50%	2024
Post-65 medical	6.00	4.50	2024
Post-65 prescription	6.75	4.50	2024

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, 2014 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$ 69	$ (58)
Service and interest costs	3	(2)

Pension Plans

The total accumulated benefit obligation for the pension plans was $3.5 billion at December 31, 2014 and $2.9 billion at December 31, 2013. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2014 and 2013 were as follows:

	2014	2013
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 3,116**	$ 3,312
Service cost	**62**	69
Interest cost	**153**	138
Benefits paid	**(149)**	(141)
Actuarial (gain) loss	**599**	(262)
Balance at end of year	**3,781**	3,116
Change in plan assets		
Fair value of plan assets at beginning of year	**3,085**	2,827
Actual return on plan assets	**285**	387
Employer contributions	**162**	12
Benefits paid	**(149)**	(141)
Fair value of plan assets at end of year	**3,383**	3,085
Accrued liability	**$ (398)**	$ (31)

At December 31, 2014, the projected benefit obligations for the qualified and non-qualified pension plans were $3.6 billion and $165 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2014 and 2013 related to the Company's pension plans consist of the following:

	2014	2013
	(in millions)	
Prepaid pension costs	**$ —**	$ 118
Other regulatory assets, deferred	**1,102**	610
Current liabilities, other	**(12)**	(12)
Employee benefit obligations	**(386)**	(137)

Presented below are the amounts included in regulatory assets at December 31, 2014 and 2013 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 2015.

	2014	2013	**Estimated Amortization in 2015**
		(in millions)	
Prior service cost	**$ 17**	$ 26	**$ 9**
Net (gain) loss	**1,085**	584	**76**
Regulatory assets	**$ 1,102**	$ 610	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2014 and 2013 are presented in the following table:

	2014	2013
	(in millions)	
Regulatory assets:		
Beginning balance	**$ 610**	$ 1,132
Net (gain) loss	**543**	(438)
Reclassification adjustments:		
Amortization of prior service costs	**(10)**	(10)
Amortization of net gain (loss)	**(41)**	(74)
Total reclassification adjustments	**(51)**	(84)
Total change	**492**	(522)
Ending balance	**$ 1,102**	$ 610

Components of net periodic pension cost were as follows:

	2014	2013	2012
		(in millions)	
Service cost	**$ 62**	$ 69	$ 60
Interest cost	**153**	138	141
Expected return on plan assets	**(228)**	(212)	(221)
Recognized net loss	**41**	74	33
Net amortization	**10**	10	12
Net periodic pension cost	**$ 38**	$ 79	$ 25

Net periodic pension cost 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, 2014, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2015	$ 199
2016	169
2017	177
2018	183
2019	190
2020 to 2024	1,042

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2014 and 2013 were as follows:

	2014	2013
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 723**	$ 800
Service cost	**6**	7
Interest cost	**34**	31
Benefits paid	**(44)**	(45)
Actuarial (gain) loss	**142**	(73)
Retiree drug subsidy	**3**	3
Balance at end of year	**864**	723
Change in plan assets		
Fair value of plan assets at beginning of year	**407**	382
Actual return on plan assets	**21**	56
Employer contributions	**8**	11
Benefits paid	**(41)**	(42)
Fair value of plan assets at end of year	**395**	407
Accrued liability	**$ (469)**	$ (316)

Amounts recognized in the balance sheets at December 31, 2014 and 2013 related to the Company's other postretirement benefit plans consist of the following:

	2014	2013
	(in millions)	
Other regulatory assets, deferred	**$ 213**	$ 69
Employee benefit obligations	**(469)**	(316)

Presented below are the amounts included in regulatory assets at December 31, 2014 and 2013 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 2015.

	2014	2013	Estimated Amortization in 2015
		(in millions)	
Prior service cost	**$ (5)**	$ (4)	**$ —**
Net (gain) loss	**218**	73	**11**
Regulatory assets	**$ 213**	$ 69	

The changes in the balance of regulatory assets related to the other postretirement benefit plans for the plan years ended December 31, 2014 and 2013 are presented in the following table:

	2014	2013
	(in millions)	
Regulatory assets:		
Beginning balance	**$ 69**	$ 187
Net (gain) loss	**146**	(106)
Reclassification adjustments:		
Amortization of transition obligation	**—**	(4)
Amortization of net gain (loss)	**(2)**	(8)
Total reclassification adjustments	**(2)**	(12)
Total change	**144**	(118)
Ending balance	**$ 213**	$ 69

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

	2014	2013	2012
		(in millions)	
Service cost	**$ 6**	$ 7	$ 7
Interest cost	**34**	31	37
Expected return on plan assets	**(25)**	(24)	(29)
Net amortization	**2**	12	10
Net periodic postretirement benefit cost	**$ 17**	$ 26	$ 25

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)	
2015	$ 53	$ (4)	$ 49
2016	56	(5)	51
2017	57	(5)	52
2018	59	(6)	53
2019	59	(6)	53
2020 to 2024	289	(32)	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. 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, 2014 and 2013, along with the targeted mix of assets for each plan, is presented below:

	Target	**2014**	2013
Pension plan assets:			
Domestic equity	26%	**30%**	31%
International equity	25	**23**	25
Fixed income	23	**27**	23
Special situations	3	**1**	1
Real estate investments	14	**14**	14
Private equity	9	**5**	6
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	40%	**38%**	36%
International equity	21	**26**	30
Domestic fixed income	24	**24**	21
Global fixed income	8	**7**	8
Special situations	1	**—**	—
Real estate investments	4	**4**	3
Private equity	2	**1**	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, 2014 and 2013. 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, 2014 and 2013 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, 2014:	**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*	$ 595	$ 246	$ —	$ 841
International equity*	373	344	—	717
Fixed income:				
U.S. Treasury, government, and agency bonds	—	244	—	244
Mortgage- and asset-backed securities	—	66	—	66
Corporate bonds	—	398	—	398
Pooled funds	—	179	—	179
Cash equivalents and other	1	230	—	231
Real estate investments	102	—	391	493
Private equity	—	—	199	199
Total	$ 1,071	$ 1,707	$ 590	$ 3,368
Liabilities:				
Derivatives	$ (1)	$ —	$ —	$ (1)
Total	$ 1,070	$ 1,707	$ 590	$ 3,367

* 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, 2013:	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*	$ 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.

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, 2014 and 2013 were as follows:

	2014		2013	
	Real Estate Investments	**Private Equity**	**Real Estate Investments**	**Private Equity**
	(in millions)			
Beginning balance	**$ 353**	**$ 202**	$ 299	$ 211
Actual return on investments:				
Related to investments held at year end	**23**	**15**	25	3
Related to investments sold during the year	**12**	**(6)**	10	17
Total return on investments	**35**	**9**	35	20
Purchases, sales, and settlements	**3**	**(12)**	19	(29)
Ending balance	**$ 391**	**$ 199**	$ 353	$ 202

The fair values of other postretirement benefit plan assets as of December 31, 2014 and 2013 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, 2014:	**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*	$ 53	$ 40	$ —	$ 93
International equity*	11	45	—	56
Fixed income:				
U.S. Treasury, government, and agency bonds	—	7	—	7
Mortgage- and asset-backed securities	—	2	—	2
Corporate bonds	—	12	—	12
Pooled funds	—	29	—	29
Cash equivalents and other	8	11	—	19
Trust-owned life insurance	—	162	—	162
Real estate investments	3	—	12	15
Private equity	—	—	6	6
Total	$ 75	$ 308	$ 18	$ 401

* 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, 2013:	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*	$ 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.

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, 2014 and 2013 were as follows:

	2014		2013	
	Real Estate Investments	**Private Equity**	**Real Estate Investments**	**Private Equity**
	(in millions)			
Beginning balance	**$ 11**	**$ 6**	$ 10	$ 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	**$ 12**	**$ 6**	$ 11	$ 6

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 2014, 2013, and 2012 were $25 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 occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters. 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. 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. In February 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. In May 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 Company's regulatory treatment for environmental remediation expenses 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 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 beginning no later than January 31, 1998. The DOE has yet to commence the performance of its contractual and statutory obligation to dispose of spent nuclear fuel. Consequently, the Company 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 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.

On December 12, 2014, the Court of Federal Claims entered a judgment in favor of the Company in its second spent nuclear fuel lawsuit seeking damages for the period from January 1, 2005 through December 31, 2010. The Company was awarded approximately $18 million, based on its ownership interests. No amounts have been recognized in the financial statements as of December 31, 2014. The final outcome of this matter cannot be determined at this time; however, no material impact on the Company's net income is expected.

On March 4, 2014, the Company filed additional lawsuits 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 for the period from January 1, 2011 through December 31, 2013. 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, 2014 for any potential recoveries from the additional lawsuits. The final outcome of these matters 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.

On-site dry spent fuel storage facilities are operational at Plant Vogtle Units 1 and 2 and Plant Hatch. Facilities at the plants can be expanded to accommodate spent fuel through the expected life of each plant.

Retail Regulatory Matters

Rate Plans

In December 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 in November 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 approximately $25 million; (3) Demand-Side Management (DSM) tariffs by approximately $1 million; and (4) Municipal Franchise Fee (MFF) tariff by approximately $4 million, for a total increase in base revenues of approximately $110 million.

On February 19, 2015, in accordance with the 2013 ARP, the Georgia PSC approved adjustments to traditional base, ECCR, DSM, and MFF tariffs effective January 1, 2015 as follows:

- Traditional base tariffs by approximately $107 million to cover additional capacity costs;
- ECCR tariff by approximately $23 million;
- DSM tariffs by approximately $3 million; and
- MFF tariff by approximately $3 million to reflect the adjustments above.

The sum of these adjustments resulted in a base revenue increase of approximately $136 million in 2015.

The 2016 base rate increase, which was approved in the 2013 ARP, will be determined through a compliance filing expected to be filed in late 2015, and will be subject to review by the Georgia PSC.

Under the 2013 ARP, the Company's retail 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. In 2014, the Company's retail ROE exceeded 12.00%, and the Company expects to refund to retail customers approximately $13 million in 2015, subject to review and approval by the Georgia PSC.

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

In July 2013, the Georgia PSC approved the Company's latest triennial Integrated Resource Plan (2013 IRP) including 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.

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 (250 MWs) was extended from December 31, 2013 as specified in the final order in the 2011 Integrated Resource Plan Update (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) were 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 in September 2013 to allow for necessary transmission system reliability improvements. In July 2013, the Georgia PSC approved the switch to natural gas as the primary fuel for Plant Yates Units 6 and 7. In September 2013, Plant Branch Unit 2 (319 MWs) was retired as approved by the Georgia PSC in the 2011 IRP Update in order to comply with the State of Georgia's Multi-Pollutant Rule.

In the 2013 ARP, the Georgia PSC approved the amortization of the 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.

On July 1, 2014, the Georgia PSC approved the Company's request to cancel the proposed biomass fuel conversion of Plant Mitchell Unit 3 (155 MWs) because it would not be cost effective for customers. The Company expects to request decertification of Plant Mitchell Unit 3 in connection with the triennial Integrated Resource Plan to be filed in 2016. The Company plans to continue to operate the unit as needed until the MATS rule becomes effective in April 2015.

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.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved a reduction in the Company's total annual billings of approximately $567 million effective June 1, 2012, with an additional $122 million reduction effective January 1, 2013 through June 1, 2014. Under an Interim Fuel Rider, 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 in February 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 January 20, 2015, the Georgia PSC approved the deferral of the Company's next fuel case filing until at least June 30, 2015.

The Company's under recovered fuel balance totaled approximately $199 million at December 31, 2014 and is included in current assets and other deferred charges and assets. At December 31, 2013, the Company's over recovered fuel balance totaled approximately $58 million and was 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, Vogtle Owners), entered into an agreement with a consortium consisting of Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc., a subsidiary of The Shaw Group Inc., which was acquired by Chicago Bridge & Iron Company N.V. (CB&I) (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 Vogtle 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. The Vogtle 3 and 4 Agreement also provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees. The Contractor's liability to the Vogtle Owners for schedule and performance liquidated damages and warranty claims is subject to a cap. In addition, the Vogtle 3 and 4 Agreement provides for limited cost sharing by the Vogtle Owners for Contractor costs under certain conditions (which have not occurred), with maximum additional capital costs under this provision attributable to the Company (based on the Company's ownership interest) of approximately $114 million. Each Vogtle 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%.

Certain payment obligations of Westinghouse and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and CB&I's The Shaw Group Inc., respectively. In the event of certain credit rating downgrades of any Vogtle Owner, such Vogtle Owner will be required to provide a letter of credit or other credit enhancement. The Vogtle Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Vogtle Owners will be required to pay certain termination costs. The Contractor may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including certain Vogtle 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 Vogtle Owners, Vogtle 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, in late 2011, and issued combined construction and operating licenses (COLs) in early 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. On December 16, 2014, the Georgia PSC approved an increase to the NCCR tariff of approximately $27 million effective January 1, 2015.

In 2012, the Vogtle 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 Vogtle Owners are responsible for these costs under the terms of the Vogtle 3 and 4 Agreement. Also in 2012, the Company and the other Vogtle Owners filed suit against the Contractor in the U.S. District Court for the Southern District of Georgia seeking a declaratory judgment that the Vogtle Owners are not responsible for these costs. In 2012, the Contractor also filed suit against the Company and the other Vogtle Owners in the U.S. District Court for the District of Columbia alleging the Vogtle Owners are responsible for these costs. In August 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 in September 2013. The portion of additional costs claimed by the Contractor in its initial complaint that would be attributable to the Company (based on the Company's ownership interest) is approximately $425 million (in 2008 dollars). The Contractor also asserted it is entitled to extensions of the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. On May 22, 2014, the Contractor filed an amended counterclaim to the suit pending in the U.S. District Court for the Southern District of Georgia alleging that (i) the design changes to the DCD imposed by the NRC delayed module production and the impacts to the Contractor are recoverable by the Contractor under the Vogtle 3 and 4 Agreement and (ii) the changes to the basemat rebar design required by the NRC caused additional costs and delays recoverable by the Contractor under the Vogtle 3 and 4 Agreement. The Contractor did not specify in its amended counterclaim the amounts relating to these new allegations; however, the Contractor has subsequently asserted related minimum damages (based on the Company's ownership interest) of $113 million. The Contractor may from time to time continue to assert that it is entitled to additional payments with respect to these allegations, any of which could be substantial. The Company has not agreed to the proposed cost or to any changes to the guaranteed substantial completion dates or that the Vogtle Owners have any responsibility for costs related to these issues. Litigation is ongoing and the Company intends to vigorously defend the positions of the Vogtle Owners. 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.

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. The Company's eighth VCM report filed in February 2013 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.

In September 2013, the Georgia PSC approved a stipulation (2013 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 completion 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 be included in rate base, provided the Company shows the costs to be reasonable and prudent. In addition, financing costs on any construction-related costs in excess of the certified amount likely would be subject to recovery through AFUDC instead of the NCCR tariff.

The Georgia PSC has approved eleven VCM reports covering the periods through June 30, 2014, including construction capital costs incurred, which through that date totaled $2.8 billion.

On January 29, 2015, the Company announced that it was notified by the Contractor of the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4, which would incrementally delay the previously disclosed estimated in-service dates by 18 months (from the fourth quarter of 2017 to the second quarter of 2019 for Unit 3 and from the fourth quarter of 2018 to the second quarter of 2020 for Unit 4). The Company has not agreed to any changes to the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. The Company does not believe that the Contractor's revised forecast reflects all efforts that may be possible to mitigate the Contractor's delay.

In addition, the Company believes that, pursuant to the Vogtle 3 and 4 Agreement, the Contractor is responsible for the Contractor's costs related to the Contractor's delay (including any related construction and mitigation costs, which could be material) and that the Vogtle Owners are entitled to recover liquidated damages for the Contractor's delay beyond the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. Consistent with the Contractor's position in the pending litigation described above, the Company expects the Contractor to contest any claims for liquidated damages and to assert that the Vogtle Owners are responsible for additional costs related to the Contractor's delay.

On February 27, 2015, the Company filed its twelfth VCM report with the Georgia PSC covering the period from July 1 through December 31, 2014, which requests approval for an additional $0.2 billion of construction capital costs incurred during that period and reflects the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4 as well as additional estimated owner-related costs of approximately $10 million per month expected to result from the Contractor's proposed 18-month delay, including property taxes, oversight costs, compliance costs, and other operational readiness costs. No Contractor costs related to the Contractor's proposed 18-month delay are included in the twelfth VCM report. Additionally, while the Company has not agreed to any change to the guaranteed substantial completion dates, the twelfth VCM report includes a requested amendment to the Plant Vogtle Units 3 and 4 certificate to reflect the Contractor's revised forecast, to include the estimated owner's costs associated with the proposed 18-month Contractor delay, and to increase the estimated total in-service capital cost of Plant Vogtle Units 3 and 4 to $5.0 billion.

The Company will continue to incur financing costs of approximately $30 million per month until Plant Vogtle Units 3 and 4 are placed in service. The twelfth VCM report estimates total associated financing costs during the construction period to be approximately $2.5 billion.

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 Vogtle Owners or the Contractor or to both.

As construction continues, the risk remains that ongoing challenges with Contractor performance including additional challenges in its fabrication, assembly, delivery, and installation of the shield building and 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. In addition, the IRS allocated production tax credits to each of Plant Vogtle Units 3 and 4, which require the applicable unit to be placed in service before 2021.

Additional claims by the Contractor or the Company (on behalf of the Vogtle 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.

Nuclear Waste Fund Fee

In November 2013, the U.S. District Court for the District of Columbia ordered the 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. On March 18, 2014, the U.S. Court of Appeals for the District of Columbia Circuit denied the DOE's request for rehearing of the November 2013 panel decision ordering that the DOE propose the nuclear waste fund fee be changed to zero. The DOE formally set the fee to zero effective May 16, 2014. On June 17, 2014, the Georgia PSC approved the Company's request to credit customers the portion of fuel cost related to the nuclear waste fund fee. The nuclear waste fund rider to the Company's fuel tariffs became effective July 1, 2014.

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 ROE. The Company's share of purchased power totaled $84 million in 2014, $91 million in 2013, and $107 million in 2012 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, 2014, 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%	$ 3,420	$ 2,059	$ 46
Plant Hatch (nuclear)	50.1	1,117	559	66
Plant Wansley (coal)	53.5	856	278	15
Plant Scherer (coal)				
Units 1 and 2	8.4	254	83	1
Unit 3	75.0	1,172	417	10
Rocky Mountain (pumped storage)	25.4	182	124	2
Intercession City (combustion-turbine)	33.3	14	5	—

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:

	2014	2013	2012
		(in millions)	
Federal –			
Current	**$ 295**	$ 277	$ 273
Deferred	**366**	374	370
	661	651	643
State –			
Current	**82**	(30)	38
Deferred	**(14)**	102	7
	68	72	45
Total	**$ 729**	$ 723	$ 688

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:

	2014	2013
	(in millions)	
Deferred tax liabilities –		
Accelerated depreciation	**$ 4,732**	$ 4,479
Property basis differences	**811**	873
Employee benefit obligations	**329**	232
Under-recovered fuel costs	**81**	—
Premium on reacquired debt	**66**	73
Regulatory assets associated with employee benefit obligations	**534**	276
Asset retirement obligations	**497**	495
Other	**160**	168
Total	**7,210**	6,596
Deferred tax assets –		
Federal effect of state deferred taxes	**148**	159
Employee benefit obligations	**642**	388
Other property basis differences	**86**	93
Other deferred costs	**86**	84
Cost of removal obligations	**11**	17
State tax credit carry forward	**170**	118
Federal tax credit carry forward	**5**	3
Over-recovered fuel costs	**—**	22
Unbilled fuel revenue	**46**	53
Asset retirement obligations	**497**	495
Other	**46**	32
Total	**1,737**	1,464
Total deferred tax liabilities, net	**5,473**	5,132
Portion included in current assets/(liabilities), net	**34**	68
Accumulated deferred income taxes	**$ 5,507**	$ 5,200

The application of bonus depreciation provisions in current tax law has significantly increased deferred tax liabilities related to accelerated depreciation.

At December 31, 2014, tax-related regulatory assets to be recovered from customers were $702 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, 2014, tax-related regulatory liabilities to be credited to customers were $106 million. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the 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 average 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 $10 million in 2014, $5 million in 2013, and $13 million in 2012. State ITCs are recognized in the period in which the credits are claimed on the state income tax return and totaled $34 million in 2014, $27 million in 2013, and $36 million in 2012. At December 31, 2014, the Company had $5 million in federal tax credit carry forwards that will expire by 2034 and $152 million in state ITC carry forwards that will expire between 2021 and 2025.

Effective Tax Rate

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

	2014	2013	2012
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**2.2**	2.5	1.6
Non-deductible book depreciation	**1.3**	1.3	1.2
AFUDC equity	**(0.8)**	(0.6)	(1.0)
Other	**(0.7)**	(0.4)	(0.1)
Effective income tax rate	**37.0%**	37.8%	36.7%

The decrease in the Company's 2014 effective tax rate is primarily the result of benefits related to emission allowances and state apportionment. 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.

Unrecognized Tax Benefits

The Company had no unrecognized tax benefits during 2014. Changes in unrecognized tax benefits in prior years were as follows:

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

The tax positions decrease from prior periods for 2013 and 2012 relate primarily to the tax accounting method change for repairs-generation assets and did not impact the effective tax rate. 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.

The Company classifies interest on tax uncertainties as interest expense. Accrued interest for unrecognized tax benefits was immaterial for all periods presented. The Company did not accrue any penalties on uncertain tax positions.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013 federal income tax return and has received a partial acceptance letter from the IRS; however, the IRS has not finalized its audit. Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2008.

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, in April 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. In September 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 continues to review this guidance; 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:

	2014	2013
	(in millions)	
Senior notes	**$ 1,050**	$ —
Pollution control revenue bonds	**98**	—
Capital lease	**6**	5
Total	**$ 1,154**	$ 5

Maturities through 2019 applicable to total long-term debt are as follows: $1.2 billion in 2015; $710 million in 2016; $457 million in 2017; $257 million in 2018; and $508 million in 2019.

Senior Notes

The Company did not issue any unsecured senior notes in 2014. At December 31, 2014 and 2013, the Company had $6.9 billion of senior notes outstanding. These senior notes are effectively subordinated to all secured debt of the Company, which aggregated $1.2 billion and $45 million at December 31, 2014 and 2013, respectively. As of December 31, 2014, the Company's secured debt included borrowings of $1.2 billion guaranteed by the DOE and capital leases. As of December 31, 2013, the Company's secured debt was related to capital lease obligations. See Note 7 for additional information.

See "DOE Loan Guarantee Borrowings" herein for additional information.

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, 2014 and 2013 was $1.6 billion and $1.7 billion, respectively. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

In July 2014, the Company reoffered to the public $40 million aggregate principal amount of Development Authority of Monroe County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Scherer Project), First Series 2009, which had been previously purchased and held by the Company since 2010.

Bank Term Loans

In February 2014, the Company repaid three four-month floating rate bank loans in an aggregate principal amount of $400 million. At December 31, 2014, the Company had no bank term loans outstanding.

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 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 for any payments the DOE is required to make to the FFB under the guarantee. The Company's reimbursement obligations to the DOE are full recourse and secured by a first priority lien on (i) the Company's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor core) 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 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 2044 and the interest rate applicable to the remaining $500 million is 3.488% for an interest period that extends to 2029, and is expected to be reset from time to time thereafter through 2044. In connection with its entry into the agreements with the DOE and the FFB, the Company incurred issuance costs of approximately $66 million, which will be amortized over the life of the borrowings under the FFB Credit Facility.

On December 11, 2014, the Company made additional borrowings under the FFB Credit Facility in an aggregate principal amount of $200 million. The interest rate applicable to the $200 million advance in December 2014 under the FFB Credit Facility is 3.002% for an interest period that extends to 2044.

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, 2014 and 2013, the Company had a capital lease asset for its corporate headquarters building of $61 million, with accumulated depreciation at December 31, 2014 and 2013 of $21 million and $16 million, respectively. At December 31, 2014 and 2013, the capitalized lease obligation was $40 million and $45 million, respectively, with an annual 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.

Assets Subject to Lien

See "DOE Loan Guarantee Borrowings" above for information regarding certain borrowings of the Company that are secured by a first priority lien on (i) the Company's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor core) and (ii) the Company's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4.

See "Capital Leases" above for information regarding certain assets held under capital leases.

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, 2014, 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 2015 or 2017.

Subject to applicable market conditions, the Company expects to renew its bank credit arrangements, as needed, prior to expiration. All of the bank 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 bank credit arrangements contain 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 unused credit with banks is allocated to provide liquidity support to the Company's variable rate pollution control revenue bonds and its commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2014 was $865 million. In addition, at December 31, 2014, the Company had $118 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months. As of December 31, 2014, $98 million of certain pollution control revenue bonds of the Company were reclassified to securities due within one year in anticipation of their redemption in connection with unit retirement decisions. See Note 3 under "Retail Regulatory Matters – Integrated Resource Plans" for additional information.

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 described above. The Company may also borrow through various other arrangements with banks. Commercial paper and short-term bank term loans are included in notes payable in the balance sheets.

The Company had $156 million and $1.0 billion of short-term debt outstanding at December 31, 2014 and 2013, respectively. Details of short-term borrowings outstanding were as follows:

	Short-term Debt at the End of the Period	
	Amount Outstanding	Weighted Average Interest Rate
	(in millions)	
December 31, 2014:		
Commercial paper	$ 156	0.3%
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 2014, 2013, and 2012, the Company incurred fuel expense of $2.5 billion, $2.3 billion, and $2.1 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 $19 million, $27 million, and $50 million in 2014, 2013, and 2012, 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 $167 million, $162 million, and $169 million for 2014, 2013, and 2012, respectively. Estimated total long-term obligations at December 31, 2014 were as follows:

	Affiliate Capital Leases	Affiliate Operating Leases	Non-Affiliate Operating Leases [4]	Vogtle Units 1 and 2 Capacity Payments	Total ($)
			(in millions)		
2015	$ 22	$ 90	$ 114	$ 11	$ 237
2016	22	100	117	11	250
2017	23	71	146	10	250
2018	23	62	150	7	242
2019	23	63	152	6	244
2020 and thereafter	255	606	1,572	50	2,483
Total	$ 368	$ 992	$ 2,251	$ 95	$ 3,706
Less: amounts representing executory costs[1]	55				
Net minimum lease payments	313				
Less: amounts representing interest[2]	85				
Present value of net minimum lease payments[3]	$ 228				

(1) Executory costs such as taxes, maintenance, and insurance (including the estimated profit thereon) are estimated and included in total minimum lease payments.

(2) Amount necessary to reduce minimum lease payments to present value calculated at the Company's incremental borrowing rate at the inception of the leases.

(3) Once service commences under the PPAs beginning in 2015, the Company will recognize capital lease assets and capital lease obligations totaling $149 million, being the lesser of the estimated fair value of the lease property or the present value of the net minimum lease payments.

(4) A total of $1.1 billion of biomass PPAs included under the non-affiliate operating leases is contingent upon the counterparties meeting specified contract dates for commercial operation and may change as a result of regulatory action.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. 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 $28 million for 2014, $32 million for 2013, and $34 million for 2012. The Company includes any step rents, fixed escalations, and lease concessions in its computation of minimum lease payments.

As of December 31, 2014, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Railcars	Other	Total
		(in millions)	
2015	$ 18	$ 7	$ 25
2016	13	7	20
2017	9	7	16
2018	4	6	10
2019	1	4	5
2020 and thereafter	3	11	14
Total	$ 48	$ 42	$ 90

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 2024 with maximum obligations under these leases of $32 million. At the termination of the leases, the lessee may either renew the lease, 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, in December 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, 2014, there were approximately 1,000 current and former employees of the Company participating in the stock option program. 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.

For the years ended December 31, 2014, 2013, and 2012, employees of the Company were granted stock options for 2,034,150 shares, 1,509,662 shares, and 1,269,725 shares, respectively. The weighted average grant-date fair value of stock options granted during 2014, 2013, and 2012, derived using the Black-Scholes stock option pricing model, was $2.20, $2.93, and $3.39, respectively.

The compensation cost and tax benefits related to the grant of Southern Company stock options to the Company's employees and the exercise of stock options are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. No cash proceeds are received by the Company upon the exercise of stock options. The amounts were not material for any year presented.

As of December 31, 2014, the amount of unrecognized compensation cost related to stock option awards not yet vested was immaterial.

The total intrinsic value of options exercised during the years ended December 31, 2014, 2013, and 2012 was $19 million, $16 million, and $34 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $7 million, $6 million, and $13 million for the years ended December 31, 2014, 2013, and 2012, respectively. As of December 31, 2014, the aggregate intrinsic value for the options outstanding and options exercisable was $73 million and $51 million, 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. Performance share units held by employees of a company undergoing a change in control vest upon the change in control.

For the years ended December 31, 2014, 2013, and 2012, employees of the Company were granted performance share units of 176,224, 161,240, and 152,812, respectively. The weighted average grant-date fair value of performance share units granted during 2014, 2013, and 2012, determined using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period, was $37.54, $40.50, and $41.99, respectively.

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. For the years ended December 31, 2014, 2013, and 2012, total compensation cost for performance share units recognized in income was $6 million annually, with the related tax benefit of $2 million annually also recognized in income. The compensation cost and tax benefits related to the grant of Southern Company performance share units 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. As of December 31, 2014, there was $7 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 20 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 $247 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 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 $1.5 billion 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 $1.25 billion for nuclear losses in excess of the $1.5 billion primary coverage. On April 1, 2014, NEIL introduced a new excess non-nuclear policy providing coverage up to $750 million for non-nuclear losses in excess of the $1.5 billion primary coverage.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. The Company purchases limits based on the projected full cost of replacement power, 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 $72 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, 2014, 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, 2014:	**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	$ —	$ 7	$ —	$ 7
Interest rate derivatives	—	6	—	6
Nuclear decommissioning trusts:[(a)]				
Domestic equity	180	2	—	182
Foreign equity	—	121	—	121
U.S. Treasury and government agency securities	—	96	—	96
Municipal bonds	—	62	—	62
Corporate bonds	—	188	—	188
Mortgage and asset backed securities	—	121	—	121
Other	11	8	—	19
Total	$ 191	$ 611	$ —	$ 802
Liabilities:				
Energy-related derivatives	$ —	$ 27	$ —	$ 27
Interest rate derivatives	—	14	—	14
Total	$ —	$ 41	$ —	$ 41

(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, 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	—	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.

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. Interest rate derivatives are also standard over-the-counter financial products valued using the market approach. Inputs for interest rate derivatives include LIBOR interest rates, interest rate futures contracts, and occasionally, implied volatility of interest rate options. See Note 11 for additional information on how these derivatives are used.

For fair value measurements of the investments within the nuclear decommissioning trusts, external pricing vendors are designated for each asset class with each security specifically assigned a primary pricing source. For investments held within commingled funds, fair value is determined at the end of each business day through the net asset value, which is established by obtaining the underlying securities' individual prices from the primary pricing source. 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, fixed income 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, 2014 and 2013, 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, 2014:	*(in millions)*			
Nuclear decommissioning trusts:				
Foreign equity fund	$ 121	None	Monthly	5 days
Other — commingled funds	8	None	Daily	Not applicable
Other — money market funds	11	None	Daily	Not applicable
As of December 31, 2013:				
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

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, 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 other-commingled funds and other-money market funds in the nuclear decommissioning trusts are invested primarily in a diversified portfolio of high quality, short-term, liquid debt securities. The funds represent the cash collateral received under the Funds' managers' securities lending program and/or the excess cash held within each separate investment account. The primary objective of the funds is to provide a high level of current income consistent with stability of principal and liquidity. The funds invest primarily in, but not limited to, commercial paper, floating and variable rate demand notes, debt securities issued or guaranteed by the U.S. government or its agencies or instrumentalities, time deposits, repurchase agreements, municipal obligations, notes, and other high-quality short-term liquid debt securities that mature in 90 days or less. Redemptions are available on a same day basis up to the full amount of the investment in the funds. See Note 1 under "Nuclear Decommissioning" for additional information.

As of December 31, 2014 and 2013, 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:		
2014	**$ 9,797**	**$ 10,552**
2013	$ 8,593	$ 8,782

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. See Note 10 for additional information. 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, 2014, the net volume of energy-related derivative contracts for natural gas positions totaled 46 million mmBtu, 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 4 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. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. 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, with any ineffectiveness recorded directly to earnings. Derivatives related to fixed rate securities are accounted for as fair value hedges, where the derivatives' fair value gains and losses and the hedged items' fair value gains and losses attributable to interest rate risk are both recorded directly to earnings, providing an offset, with any differences representing ineffectiveness.

At December 31, 2014, the following interest rate derivatives were outstanding:

	Notional Amount	Interest Rate Received	Weighted Average Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2014
	(in millions)				*(in millions)*
Cash Flow Hedges of Forecasted Debt					
	$ 350	3-month LIBOR	2.57%	May 2025	$ (6)
	350	3-month LIBOR	2.57%	November 2025	(2)
Cash Flow Hedges of Existing Debt					
	250	3-month LIBOR + 0.32%	0.75%	March 2016	—
	200	3-month LIBOR + 0.40%	1.01%	August 2016	—
Fair value hedges of existing debt					
	250	5.40%	3-month LIBOR + 4.02%	June 2018	(1)
	200	4.25%	3-month LIBOR + 2.46%	December 2019	—
Total	$ 1,600				$ (9)

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2015 are immaterial. The Company has deferred gains and losses related to interest rate derivative settlements of cash flow hedges that are expected to be amortized into earnings through 2037.

Derivative Financial Statement Presentation and Amounts

At December 31, 2014 and 2013, the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2014**	2013	**Balance Sheet Location**	**2014**	2013
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ 6**	$ 3	Liabilities from risk management activities	**$ 23**	$ 13
	Other deferred charges and assets	**1**	2	Other deferred credits and liabilities	**4**	8
Total derivatives designated as hedging instruments for regulatory purposes		**$ 7**	$ 5		**$ 27**	$ 21
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Interest rate derivatives:	Other current assets	**$ 5**	$ —	Liabilities from risk management activities	**$ 9**	$ —
	Other deferred charges and assets	**1**	—	Other deferred credits and liabilities	**5**	—
Total derivatives designated as hedging instruments in cash flow and fair value hedges		**$ 6**	$ —		**$ 14**	$ —
Total		**$ 13**	$ 5		**$ 41**	$ 21

Energy-related derivatives not designated as hedging instruments were immaterial on the balance sheets for 2014 and 2013.

The derivative contracts of the Company are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related and interest rate derivative contracts may 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 and interest rate derivative contracts at December 31, 2014 and 2013 are presented in the following tables.

Fair Value					
Assets	**2014**	2013	**Liabilities**	**2014**	2013
	(in millions)			*(in millions)*	
Energy-related derivatives presented in the Balance Sheet [(a)]	**$ 7**	$ 5	Energy-related derivatives presented in the Balance Sheet [(a)]	**$ 27**	$ 21
Gross amounts not offset in the Balance Sheet [(b)]	**(7)**	(5)	Gross amounts not offset in the Balance Sheet [(b)]	**(7)**	(5)
Net energy-related derivative assets	**$ —**	$ —	**Net energy-related derivative liabilities**	**$ 20**	$ 16
Interest rate derivatives presented in the Balance Sheet [(a)]	**$ 6**	$ —	Interest rate derivatives presented in the Balance Sheet [(a)]	**$ 14**	$ —
Gross amounts not offset in the Balance Sheet [(b)]	**(6)**	—	Gross amounts not offset in the Balance Sheet [(b)]	**(6)**	—
Net interest rate derivative assets	**$ —**	$ —	**Net interest rate derivative liabilities**	**$ 8**	$ —

(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, 2014 and 2013, 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**	**2014**	2013	**Balance Sheet Location**	**2014**	2013
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$ (23)**	$ (13)	Other regulatory liabilities, current	**$ 6**	$ 3
	Other regulatory assets, deferred	**(4)**	(8)	Other deferred credits and liabilities	**1**	2
Total energy-related derivative gains (losses)		**$ (27)**	$ (21)		**$ 7**	$ 5

For the year ended December 31, 2014, the pre-tax effect of interest rate derivatives designated as fair value hedging instruments on the statement of income was immaterial on a gross basis for the Company. Furthermore, the pre-tax effect of interest rate derivatives designated as fair value hedging instruments on the Company's statement of income was offset by changes to the carrying value of the long-term debt. The gains and losses related to interest rate derivative settlements of fair value hedges are recorded directly to earnings.

The pre-tax effects of interest rate derivatives designated as cash flow hedging instruments include $8 million of losses recognized in OCI for the year ended December 31, 2014 and amounts reclassified from accumulated OCI into earnings that were immaterial for all years presented.

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, 2014, the Company's collateral posted with its derivative counterparties was immaterial.

At December 31, 2014, the fair value of derivative liabilities with contingent features was $4 million. However, because of 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 $54 million, and include 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. 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.

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 and S&P 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 2014 and 2013 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
		(in millions)	
March 2014	**$ 2,269**	**$ 516**	**$ 266**
June 2014	**2,186**	**572**	**311**
September 2014	**2,631**	**920**	**525**
December 2014	**1,902**	**288**	**123**
March 2013	$ 1,882	$ 412	$ 197
June 2013	2,042	552	282
September 2013	2,484	872	487
December 2013	1,866	404	208

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

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		2014		2013		2012		2011		2010
Operating Revenues (in millions)	**$**	**8,988**	$	8,274	$	7,998	$	8,800	$	8,349
Net Income After Dividends on Preferred and Preference Stock (in millions)	**$**	**1,225**	$	1,174	$	1,168	$	1,145	$	950
Cash Dividends on Common Stock (in millions)	**$**	**954**	$	907	$	983	$	1,096	$	820
Return on Average Common Equity (percent)		**12.24**		12.45		12.76		12.89		11.42
Total Assets (in millions)	**$**	**31,030**	$	28,907	$	28,803	$	27,151	$	25,914
Gross Property Additions (in millions)	**$**	**2,146**	$	1,906	$	1,838	$	1,981	$	2,401
Capitalization (in millions):										
Common stock equity	**$**	**10,421**	$	9,591	$	9,273	$	9,023	$	8,741
Preferred and preference stock		**266**		266		266		266		266
Long-term debt		**8,683**		8,633		7,994		8,018		7,931
Total (excluding amounts due within one year)	**$**	**19,370**	$	18,490	$	17,533	$	17,307	$	16,938
Capitalization Ratios (percent):										
Common stock equity		**53.8**		51.9		52.9		52.1		51.6
Preferred and preference stock		**1.4**		1.4		1.5		1.5		1.6
Long-term debt		**44.8**		46.7		45.6		46.4		46.8
Total (excluding amounts due within one year)		**100.0**		100.0		100.0		100.0		100.0
Customers (year-end):										
Residential		**2,102,673**		2,080,358		2,062,040		2,047,390		2,049,770
Commercial*		**301,246**		298,420		296,397		295,288		295,347
Industrial*		**9,132**		9,136		9,143		9,134		8,929
Other		**9,003**		8,623		7,724		7,521		7,309
Total		**2,422,054**		2,396,537		2,375,304		2,359,333		2,361,355
Employees (year-end)		**7,909**		7,886		8,094		8,310		8,330

* A reclassification of customers from commercial to industrial is reflected for years 2010-2013 to be consistent with the rate structure approved by the Georgia PSC. The impact to operating revenues, kilowatt-hour sales, and average revenue per kilowatt-hour by class is not material.

	2014	2013	2012	2011	2010
Operating Revenues (in millions):					
Residential	**$ 3,350**	$ 3,058	$ 2,986	$ 3,241	$ 3,072
Commercial	**3,271**	3,077	2,965	3,217	3,011
Industrial	**1,525**	1,391	1,322	1,547	1,441
Other	**94**	94	89	94	84
Total retail	**8,240**	7,620	7,362	8,099	7,608
Wholesale — non-affiliates	**335**	281	281	341	380
Wholesale — affiliates	**42**	20	20	32	53
Total revenues from sales of electricity	**8,617**	7,921	7,663	8,472	8,041
Other revenues	**371**	353	335	328	308
Total	**$ 8,988**	$ 8,274	$ 7,998	$ 8,800	$ 8,349
Kilowatt-Hour Sales (in millions):					
Residential	**27,132**	25,479	25,742	27,223	29,433
Commercial	**32,426**	31,984	32,270	32,900	33,855
Industrial	**23,549**	23,087	23,089	23,519	23,209
Other	**633**	630	641	657	663
Total retail	**83,740**	81,180	81,742	84,299	87,160
Wholesale — non-affiliates	**4,323**	3,029	2,934	3,904	4,662
Wholesale — affiliates	**1,117**	496	600	626	1,000
Total	**89,180**	84,705	85,276	88,829	92,822
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**12.35**	12.00	11.60	11.91	10.44
Commercial	**10.09**	9.62	9.19	9.78	8.89
Industrial	**6.48**	6.03	5.73	6.58	6.21
Total retail	**9.84**	9.39	9.01	9.61	8.73
Wholesale	**6.93**	8.54	8.52	8.23	7.65
Total sales	**9.66**	9.35	8.99	9.54	8.66
Residential Average Annual Kilowatt-Hour Use Per Customer	**12,969**	12,293	12,509	13,288	14,367
Residential Average Annual Revenue Per Customer	**$ 1,605**	$ 1,475	$ 1,451	$ 1,582	$ 1,499
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**17,593**	17,586	17,984	16,588	15,992
Maximum Peak-Hour Demand (megawatts):					
Winter	**16,308**	12,767	14,104	14,800	15,614
Summer	**15,777**	15,228	16,440	16,941	17,152
Annual Load Factor (percent)	**61.2**	63.5	59.1	59.5	60.9
Plant Availability (percent)*:					
Fossil-steam	**86.3**	87.1	90.3	88.6	88.6
Nuclear	**90.8**	91.8	94.1	92.2	94.0
Source of Energy Supply (percent):					
Coal	**30.9**	26.4	26.6	44.4	51.8
Nuclear	**16.7**	17.7	18.3	16.6	16.4
Hydro	**1.3**	2.0	0.7	1.1	1.4
Oil and gas	**26.3**	29.6	22.0	8.9	8.0
Purchased power —					
From non-affiliates	**3.8**	3.3	6.8	6.1	5.2
From affiliates	**21.0**	21.0	25.6	22.9	17.2
Total	**100.0**	100.0	100.0	100.0	100.0

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

Directors

W. Paul Bowers (Elected Chairman effective 5/21/2014)
Chairman, 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 (Resigned effective 2/11/2015)
Chairman, President, and Chief Executive Officer
The Southern Company

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

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

Charles K. Tarbutton
Assistant Vice President
Sandersville Railroad Company

Beverly Daniel Tatum
President
Spelman College

D. Gary Thompson
Retired Chief Executive Officer
Georgia Banking, Wachovia Bank, N.A.

Clyde C. Tuggle
Senior Vice President and 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 (Elected Chairman effective 5/21/2014)
Chairman, 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

Pedro P. Cherry (Elected effective 3/28/2015)
Senior Vice President
Metro Atlanta Region

Walter Dukes (Retired effective 4/1/2015)
Senior Vice President
Metro Atlanta Region

Kenneth E. Coleman (Elected effective 3/28/2015)
Senior Vice President
Marketing

Michael A. Hazelton (Resigned effective 3/28/2015)
Senior Vice President
Marketing

John L. Pemberton
Senior Vice President and
Senior Production Officer
Generation

DIRECTORS AND OFFICERS
Georgia Power Company 2014 Annual Report

Latanza W. Adjei (Elected effective 3/28/2015)
Vice President
Sales

Tami M. Barron (Resigned effective 1/31/2015)
Vice President
Supply Chain Management

Daryl E. Brown (Elected effective 3/28/2015)
Vice President
Central Region

Melissa K. Caen
Assistant Secretary

Moanica M. Caston
Vice President
Diversity and Inclusion

Lenn H. Chandler
Vice President
Northeast Region

P. Mike Clanton
Vice President
Land

Jason T. Cuevas
Vice President
Corporate Communication

J. Truitt Eavenson
Vice President
Governmental and Regulatory Affairs

Nicole A. Faulk (Elected effective 3/28/2015)
Vice President
West Region

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

Glen R. Grizzle (Elected effective 3/28/2015)
Vice President
East Region

Cathy P. Hill
Vice President
Coastal Region

Anne H. Kaiser
Vice President
Community and Economic Development

Stacy R. Kilcoyne
Vice President
Human Resource Services

Danny W. Lindsey
Vice President
Transmission

Earl C. Long
Assistant Treasurer

Jacki W. Lowe (Retired effective 4/1/2015)
Vice President
West Region

Terri H. Lupo (Retired effective 4/1/2015)
Vice President
South Region

Jason E. Manley (Elected effective 3/28/2015)
Vice President
South Region

William N. (Norrie) McKenzie
Vice President
Renewable Development

David L. McKinney (Elected effective 5/29/2014)
Vice President
Nuclear Develpment

Christie D. Miree (Elected effective 5/21/2014)
Vice President
Information Technology

Leonard Owens
Vice President
Human Resources and Labor

Laura I. Patterson (Resigned effective 8/16/2014)
Comptroller and Assistant Secretary

David P. Poroch (Elected effective 8/16/2014)
Vice President and Comptroller

D. Emi Rahn (Elected effective 8/16/2014)
Assistant Secretary

Gregory N. Roberts
Vice President
Pricing and Planning

Louise L. Scott
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. Murry Weaver II
Vice President
Northwest Region

Thomas J. Wicker (Retired effective 4/1/2015)
Vice President
Central Region

James D. Wynn, Jr. (Retired effective 4/1/2015)
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 2014, retail energy sales accounted for 94% of the Company's total sales of 89.2 billion kilowatt-hours.

The Company is a wholly-owned subsidiary of 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	2014	2013
	(in thousands)	
First	$238,400	$226,750
Second	238,400	226,750
Third	238,400	226,750
Fourth	238,400	226,750

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.
Atlanta, GA 30308-3374
(404) 506-6526

Auditors
Deloitte & Touche LLP
Suite 2000
191 Peachtree Street, N.E.
Atlanta, GA 30303

Legal Counsel
Troutman Sanders LLP
600 Peachtree Street, N.E.
Suite 5200
Atlanta, GA 30308