GEORGIA POWER COMPANY

2015 ANNUAL REPORT

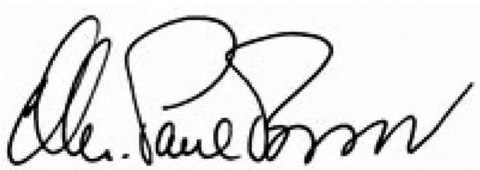
GEORGIA POWER

A SOUTHERN COMPANY

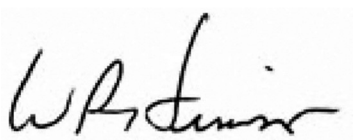
MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Georgia Power Company 2015 Annual Report

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, 2015.



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



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

February 26, 2016

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, 2015 and 2014, 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, 2015. 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 33 to 81) present fairly, in all material respects, the financial position of Georgia Power Company as of December 31, 2015 and 2014, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
February 26, 2016

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	U.S. 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	The Southern Company
Southern Company system	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

OVERVIEW

Business Activities

Georgia Power Company (the Company) operates as a vertically integrated utility providing electricity to retail customers within its traditional service territory 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, construction continues on Plant Vogtle Units 3 and 4. The Company will own a 45.7% interest in these two nuclear generating units to increase its generation diversity and meet future supply needs. On December 31, 2015, the Company and the other parties to the commercial litigation related to the construction of Plant Vogtle Units 3 and 4 entered into a settlement agreement resulting in the dismissal of the litigation. The Company has various regulatory mechanisms that operate to address cost recovery. Effectively operating pursuant to these regulatory mechanisms and appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future. See Note 3 to the financial statements under "Retail Regulatory Matters – Nuclear Construction" for additional information on Plant Vogtle Units 3 and 4.

In accordance with the 2013 ARP approved by the Georgia PSC, the Company increased base rates approximately $110 million, $136 million, and $140 million effective January 1, 2014, 2015, and 2016, respectively. The Company is required 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, but not limited to, 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 2015.

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 2015 Peak Season EFOR of 1.21% 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 2015 performance was below the target for these transmission and distribution reliability measures primarily due to the level of storm activity in the service territory during the year.

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

Earnings

The Company's 2015 net income after dividends on preferred and preference stock was $1.3 billion, representing a $35 million, or 2.9%, increase over the previous year. The increase was due primarily to an increase in base retail revenues effective January 1, 2015, as authorized by the Georgia PSC, and lower non-fuel operations and maintenance expenses, partially offset by the correction of an error affecting billings since 2013 to a small number of large commercial and industrial customers under a rate plan allowing for variable demand-driven pricing. See Note 1 to the financial statements under "General" for additional information.

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.

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

	Amount	Increase (Decrease) from Prior Year	
	2015	**2015**	2014
		(in millions)	
Operating revenues	**$ 8,326**	**$ (662)**	$ 714
Fuel	**2,033**	**(514)**	240
Purchased power	**864**	**(124)**	104
Other operations and maintenance	**1,844**	**(58)**	248
Depreciation and amortization	**846**	**—**	39
Taxes other than income taxes	**391**	**(18)**	27
Total operating expenses	**5,978**	**(714)**	658
Operating income	**2,348**	**52**	56
Interest expense, net of amounts capitalized	**363**	**15**	(13)
Other income (expense), net	**61**	**38**	(12)
Income taxes	**769**	**40**	6
Net income	**1,277**	**35**	51
Dividends on preferred and preference stock	**17**	**—**	—
Net income after dividends on preferred and preference stock	**$ 1,260**	**$ 35**	$ 51

Operating Revenues

Operating revenues for 2015 were $8.3 billion, reflecting a $662 million decrease from 2014. Details of operating revenues were as follows:

	Amount	
	2015	2014
	(in millions)	
Retail — prior year	**$ 8,240**	$ 7,620
Estimated change resulting from —		
Rates and pricing	**88**	183
Sales growth	**63**	21
Weather	**(19)**	139
Fuel cost recovery	**(645)**	277
Retail — current year	**7,727**	8,240
Wholesale revenues —		
Non-affiliates	**215**	335
Affiliates	**20**	42
Total wholesale revenues	**235**	377
Other operating revenues	**364**	371
Total operating revenues	**$ 8,326**	$ 8,988
Percent change	**(7.4)%**	8.6%

Retail base revenues of $5.3 billion in 2015 increased $133 million, or 2.6%, compared to 2014. 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, 2015, as approved by the Georgia PSC in accordance with 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, partially offset by the correction of an error affecting billings since 2013 to a small number of large commercial and industrial customers under a rate plan allowing for variable demand-driven pricing. In 2015, residential base revenues increased $104 million, or 4.5%, commercial base revenues increased $70 million, or 3.4%, and industrial base revenues decreased $41 million, or 5.6%, compared to 2014.

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 accordance with 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 variable demand-driven pricing 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.

See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth 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:

	2015	2014	2013
		(in millions)	
Capacity and other	**$ 108**	$ 164	$ 174
Energy	**107**	171	107
Total non-affiliated	**$ 215**	$ 335	$ 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 non-affiliated sales decreased $120 million, or 35.8%, in 2015 as compared to 2014 and increased $54 million, or 19.2%, in 2014 as compared to 2013. The decrease in 2015 was related to decreases of $64 million in energy revenues and $56 million in capacity revenues. The decrease in energy revenues was primarily due to lower natural gas prices. The decrease in capacity revenues reflects the expiration of wholesale contracts in December 2014 and the retirement of 14 coal-fired generating units as a result of the Company's environmental compliance strategy. 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. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" and – "Retail Regulatory Matters – Integrated Resource Plan" herein for additional information regarding the Company's environmental compliance strategy.

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 2015, wholesale revenues from sales to affiliates decreased $22 million as compared to 2014 due to lower natural gas prices and a 50.6% decrease in KWH sales due to the higher cost of Company-owned generation compared to the market cost of available energy. 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.

Other operating revenues decreased $7 million, or 1.9%, in 2015 from the prior year primarily due to a $16 million decrease in transmission service revenues primarily as a result of a contract that expired in December 2014, partially offset by an $11 million increase in outdoor lighting revenues. 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.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2015 and the percent change from the prior year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2015	**2015**	2014	**2015**	2014
	(in billions)				
Residential	**26.7**	**(1.8)%**	6.5%	**1.0%**	0.5%
Commercial	**32.7**	**0.9**	1.4	**1.5**	(0.2)
Industrial	**23.8**	**1.1**	2.0	**1.0**	1.5
Other	**0.6**	**(0.2)**	0.5	**(0.1)**	0.3
Total retail	**83.8**	**0.1**	3.2	**1.2%**	0.5%
Wholesale					
Non-affiliates	**3.5**	**(19.0)**	42.6		
Affiliates	**0.6**	**(50.6)**	125.4		
Total wholesale	**4.1**	**(25.5)**	54.2		
Total energy sales	**87.9**	**(1.5)%**	5.3%		

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 2015, KWH sales for the residential class decreased compared to 2014 primarily due to milder weather in the first and fourth quarters 2015 as compared to the corresponding periods in 2014 and decreased customer usage, partially offset by an increase in customer growth. Weather-adjusted residential KWH sales increased by 1.0% primarily due to an increase of approximately 25,000 residential customers during 2015. Household income, one of the primary drivers of residential customer usage, had modest growth in 2015. Weather-adjusted commercial KWH sales increased by 1.5% primarily due to an increase of approximately 3,000 customers and an increase in customer usage. Weather-adjusted industrial KWH sales increased by 1.0% primarily due to increased demand in the pipeline, rubber, and paper sectors, partially offset by decreased demand in the chemicals and primary metals sectors.

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 was the main contributor to the increase in industrial sales in 2014 compared to 2013. Weather-adjusted commercial KWH sales decreased by 0.2% primarily due to decreased customer usage, largely offset by customer growth. Weather-adjusted residential KWH sales increased by 0.5% primarily due to customer growth, largely offset by decreased customer usage. Household income, one of the primary drivers of residential customer usage, was flat in 2014.

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:

	2015	2014	2013
Total generation *(billions of KWHs)*	**65.9**	69.9	66.8
Total purchased power *(billions of KWHs)*	**25.6**	23.1	21.4
Sources of generation *(percent)* —			
Coal	**34**	41	35
Nuclear	**25**	22	23
Gas	**39**	35	39
Hydro	**2**	2	3
Cost of fuel, generated *(cents per net KWH)* —			
Coal	**4.55**	4.52	4.92
Nuclear	**0.78**	0.90	0.91
Gas	**2.47**	3.67	3.33
Average cost of fuel, generated *(cents per net KWH)*	**2.77**	3.40	3.32
Average cost of purchased power *(cents per net KWH)**	**4.33**	5.20	4.83

* 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 $2.9 billion in 2015, a decrease of $638 million, or 18.0%, compared to 2014. The decrease was primarily due to a $544 million decrease in the average cost of fuel and purchased power largely as a result of lower natural gas prices and a $228 million decrease in the volume of KWHs generated by coal, partially offset by a $134 million increase in the volume of KWHs purchased due to lower natural gas prices.

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 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 $2.0 billion in 2015, a decrease of $514 million, or 20.2%, compared to 2014. The decrease was primarily due to a decrease of 32.7% in the average cost of natural gas per KWH generated and a decrease of 22.2% in the volume of KWHs generated by coal, partially offset by a 6.2% increase in the volume of KWHs generated by natural gas. 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.

Purchased Power - Non-Affiliates

Purchased power expense from non-affiliates was $289 million in 2015, an increase of $2 million, or 0.7%, compared to 2014. The increase was primarily due to a 28.1% increase in the volume of KWHs purchased to meet customer demand, partially offset by a 19.8% decrease in the average cost per KWH purchased due to lower natural gas prices. 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.

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 $575 million in 2015, a decrease of $126 million, or 18.0%, compared to 2014. The decrease was primarily due to a decrease of 17.4% in the average cost per KWH purchased reflecting lower natural gas prices, partially offset by an 8.1% increase in the volume of KWHs purchased to meet customer demand. 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.

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 2015, other operations and maintenance expenses decreased $58 million, or 3.0%, compared to 2014. The decrease was primarily due to decreases of $51 million in transmission operating expenses, primarily due to gains from sales of assets and billing adjustments with integrated transmission system owners, $28 million in transmission and distribution overhead line maintenance, and $11 million in workers compensation and legal expense related to a lower volume of claims, partially offset by an increase of $33 million in employee benefits including pension costs. See Note 2 to the financial statements for additional information on pension costs.

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.

Depreciation and Amortization

Depreciation and amortization remained flat in 2015 compared to 2014 primarily due to a $16 million decrease related to unit retirements and a $9 million decrease related to other cost of removal obligations, partially offset by a $23 million increase related to additional plant in service.

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.

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

Taxes Other Than Income Taxes

In 2015, taxes other than income taxes decreased $18 million, or 4.4%, compared to 2014. The decrease was primarily due to decreases of $15 million in municipal franchise fees related to lower retail revenues and $5 million in payroll 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.

Interest Expense, Net of Amounts Capitalized

In 2015, interest expense, net of amounts capitalized increased $15 million, or 4.3%, from the prior year. The increase was primarily due to a $23 million increase in interest due to additional long-term debt borrowings from the FFB, partially offset by an $11 million decrease in interest on senior notes due to redemptions and maturities.

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.

Other Income (Expense), Net

In 2015, other income (expense), net increased $38 million from the prior year primarily due to increases of $9 million in wholesale operating fee revenue and $9 million in customer contributions in aid of construction, as well as a $9 million decrease in donations.

In 2014, other income (expense), net decreased $12 million from the prior year primarily due to a $9 million increase in donations and an $8 million decrease in wholesale operating fee revenue, partially offset by an increase in AFUDC equity due to an increase in construction related to ongoing environmental and transmission projects.

Income Taxes

Income taxes increased $40 million, or 5.5%, in 2015 compared to the prior year primarily due to higher pre-tax earnings and the recognition in 2014 of tax benefits related to emissions allowances and state apportionment.

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.

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. Demand for electricity is partially driven by economic growth. The pace of economic growth and electricity demand may be affected by changes in regional and global economic conditions, which 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, as compliance plans are revised or updated, and as legal challenges to rules are completed. 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.

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; the Migratory Bird Treaty Act; the Bald and Golden Eagle Protection 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 2015, the Company had invested approximately $5.0 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $0.3 billion, $0.4 billion, and $0.3 billion for 2015, 2014, and 2013, respectively. The Company expects that capital expenditures to comply with environmental statutes and regulations will total approximately $0.7 billion from 2016 through 2018, with annual totals of approximately $0.3 billion, $0.2 billion, and $0.2 billion for 2016, 2017, and 2018, respectively. These estimated expenditures do not include any potential capital expenditures that may arise from the EPA's final rules and guidelines or subsequently approved state plans that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" herein for additional information. The Company also anticipates costs associated with closure in place or by other methods, and ground water monitoring of ash ponds in accordance with the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), which are not reflected in the capital expenditures above, as these costs are associated with the Company's asset retirement obligation (ARO) liabilities. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations, including the 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 Plan" herein for additional information on planned unit retirements and fuel conversions.

Compliance with any new federal or state legislation or regulations relating to air, water, and land resources 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. 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. The compliance deadline set by the final MATS rule was April 16, 2015, with provisions for extensions to April 16, 2016. The implementation strategy for the MATS rule includes emission controls, retirements, and fuel conversions to achieve compliance by the deadlines applicable to each Company unit. On June 29, 2015, the U.S. Supreme Court issued a decision finding that in developing the MATS rule the EPA had failed to properly consider costs in its decision to regulate hazardous air pollutant emissions from electric generating units. On December 15, 2015, the U.S. Court of Appeals for the District of Columbia Circuit remanded the MATS rule to the EPA without vacatur to respond to the U.S. Supreme Court's decision. The EPA's supplemental finding in response to the U.S. Supreme Court's decision, which the EPA proposes to finalize in April 2016, is not expected to have any impact on the MATS rule compliance requirements and deadlines.

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 revised eight-hour ozone NAAQS, and published its final area designations in 2012. The only area within the Company's service territory designated as an ozone nonattainment area for the 2008 standard is a 15-county area within metropolitan Atlanta. On October 26, 2015, the EPA published a more stringent eight-hour ozone NAAQS. This new standard could potentially require additional emission controls, improvements in control efficiency, and operational fuel changes and could affect the siting of new generating facilities. States will recommend area designations by October 2016, and the EPA is expected to finalize them by October 2017.

The EPA regulates fine particulate matter concentrations on an annual and 24-hour average basis. All areas within the Company's service territory have achieved attainment with the 1997 and 2006 particulate matter NAAQS and the EPA has officially redesignated former nonattainment areas within the service territory as attainment for these standards. 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 in December 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.

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 finalized a data requirements rule to support 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 having begun in 2015 and Phase II beginning in 2017. On July 28, 2015, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion invalidating certain emissions budgets under the CSAPR Phase II emissions trading program for a number of states, including Georgia, Alabama, and Florida, but rejected all other pending challenges to the rule. The court's decision leaves the emissions trading program in place and remands the rule to the EPA for further action consistent with the court's decision. On December 3, 2015, the EPA published a proposed revision to CSAPR that would revise existing ozone-season emissions budgets for nitrogen oxide in Alabama and would remove Florida from the CSAPR program. The EPA proposes to finalize this rulemaking by summer 2016.

The EPA finalized regional haze regulations 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 (CT). If finalized as proposed, the revisions would apply the NSPS to all new, reconstructed, and modified CTs (including CTs at combined cycle units) during all periods of operation, including startup and shutdown, and alter the criteria for determining when an existing CT has been reconstructed.

On June 12, 2015, the EPA published a final rule requiring certain states (including Georgia, Alabama, and Florida) to revise or remove 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) by no later than November 22, 2016.

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, regional haze regulations, 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 capital expenditures and 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 or through PPAs.

In addition to the federal air quality laws described above, the Company has also been subject to the requirements of the 2007 State of Georgia Multi-Pollutant Rule. The Multi-Pollutant Rule and a companion rule required reductions in emissions of mercury, SO_2, and nitrogen oxide state-wide through the installation of specified control technologies and a 95% reduction in SO_2 emissions at certain coal-fired generating units by specific dates between 2008 and 2015. In 2015, the Company completed implementation of the measures necessary to comply with the Georgia Multi-Pollutant Rule at all 16 of its coal-fired generating units required to be controlled under the rule.

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 in October 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. National Pollutant Discharge Elimination System permits issued after July 14, 2018 must include conditions to implement and ensure compliance with the standards and protective measures required by the rule. The ultimate impact of this rule will also depend on the outcome of ongoing legal challenges and cannot be determined at this time.

On November 3, 2015, the EPA published a final effluent guidelines rule which imposes stringent technology-based requirements for certain wastestreams from steam electric power plants. The revised technology-based limits and compliance dates will be incorporated into future renewals of National Pollutant Discharge Elimination System permits at affected units and may require the installation and operation of multiple technologies sufficient to ensure compliance with applicable new numeric wastewater compliance limits. Compliance deadlines between November 1, 2018 and December 31, 2023 will be established in permits based on information provided for each applicable wastestream. The ultimate impact of these requirements will depend on pending and any future legal challenges, compliance dates, and implementation of the final rule and cannot be determined at this time.

On June 29, 2015, the EPA and the U.S. Army Corps of Engineers jointly published a final rule revising the regulatory definition of waters of the U.S. for all Clean Water Act (CWA) programs. The final rule significantly expands the scope of federal jurisdiction under the CWA and could have significant impacts on economic development projects which could affect customer demand growth. In addition, 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. The rule became effective August 28, 2015, but on October 9, 2015, the U.S. Court of Appeals for the Sixth Circuit issued an order staying implementation of the final rule. The ultimate impact of the final rule will depend on the outcome of this and other pending legal challenges and the EPA's and the U.S. Army Corps of Engineers' field-level implementation of the rule and cannot be determined at this time.

These 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 or through PPAs.

Coal Combustion Residuals

The Company currently manages CCR at onsite units consisting of landfills and surface impoundments (CCR Units) at 11 electric generating plants, including some that have recently retired. 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 April 17, 2015, the EPA published the CCR Rule in the Federal Register, which became effective on October 19, 2015. The CCR Rule regulates 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 automatically require 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 required 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.

Based on initial cost estimates for closure in place or by other methods, and groundwater monitoring of ash ponds pursuant to the CCR Rule, the Company recorded incremental AROs related to the CCR Rule. As further analysis is performed, including evaluation of the expected method of compliance, refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, and the determination of timing, including the potential for closing ash ponds prior to the end of their currently anticipated useful life, the Company expects to continue to periodically update these estimates. The Company is currently completing an analysis of the plan of closure for all ash ponds, including the timing of closure and related cost recovery through regulated rates subject to Georgia PSC approval. Based on the results of that analysis, the Company may accelerate the timing of some ash pond closures which could increase its ARO liabilities from the amounts presently recorded. 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 Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information regarding the Company's AROs as of December 31, 2015.

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 affected sites. 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

On October 23, 2015, the EPA published two final actions that would limit CO_2 emissions from fossil fuel-fired electric generating units. One of the final actions contains specific emission standards governing CO_2 emissions from new, modified, and reconstructed units. The other final action, known as the Clean Power Plan, establishes guidelines for states to develop plans to meet EPA-mandated CO_2 emission rates or emission reduction goals for existing units. The EPA's final guidelines require state plans to meet interim CO_2 performance rates between 2022 and 2029 and final rates in 2030 and thereafter. At the same time, the EPA published a proposed federal plan and model rule that, when finalized, states can adopt or that would be put in place if a state either does not submit a state plan or its plan is not approved by the EPA. On February 9, 2016, the U.S. Supreme Court granted a stay of the Clean Power Plan, pending disposition of petitions for its review with the courts. The stay will remain in effect through the resolution of the litigation, whether resolved in the U.S. Court of Appeals for the District of Columbia Circuit or the U.S. Supreme Court.

These 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 or through PPAs. However, the ultimate financial and operational impact of the final rules on the Company cannot be determined at this time and will depend upon numerous factors, including the Company's ongoing review of the final rules; the outcome of legal challenges, including legal challenges filed by the traditional operating companies; individual state implementation of the EPA's final 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.

The United Nations 21st international climate change conference took place in late 2015. The result was the adoption of the Paris Agreement, which establishes a non-binding universal framework for addressing greenhouse gas emissions based on nationally determined contributions. It also sets in place a process for increasing those commitments every five years. The ultimate impact of this agreement depends on its ratification and implementation by participating countries and cannot be determined at this time.

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 2014 greenhouse gas emissions were approximately 38 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2015 greenhouse gas emissions on the same basis is approximately 31 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.

FERC Matters

The Company has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional operating companies (including the Company) and Southern Power filed a triennial market power analysis in June 2014, which included continued reliance on the energy auction as tailored mitigation. On April 27, 2015, the FERC issued an order finding that the traditional operating companies' (including the Company's) and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional operating companies and in some adjacent areas. The FERC directed the traditional operating companies (including the

Company) and Southern Power to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional operating companies (including the Company) and Southern Power filed a request for rehearing on May 27, 2015 and on June 26, 2015 filed their response with the FERC. The ultimate outcome of this matter cannot be determined at this time.

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 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.

On December 16, 2015, in accordance with the 2013 ARP, the Georgia PSC approved an increase to tariffs effective January 1, 2016 as follows: (1) traditional base tariff rates by approximately $49 million; (2) ECCR tariff by approximately $75 million; (3) DSM tariffs by approximately $3 million; and (4) MFF tariff by approximately $13 million, for a total increase in base revenues of approximately $140 million.

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. In 2014, the Company's retail ROE exceeded 12.00%, and the Company will refund to retail customers approximately $11 million in 2016, as approved by the Georgia PSC on February 18, 2016. In 2015, the Company's retail ROE was within the allowed retail ROE range.

The Company is required to file a general base 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

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

As part of the Georgia Power Advanced Solar Initiative (ASI), the Company executed ten PPAs that were approved by the Georgia PSC in 2014 and provide for the purchase of energy from 515 MWs of solar capacity. Two PPAs began in December 2015 and eight are expected to begin in December 2016, all of which have terms ranging from 20 to 30 years. As a result of certain acquisitions by Southern Power, the Company expects that 249 MWs of the 515 MWs of contracted capacity will be purchased from solar facilities owned or under development by Southern Power.

In October 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. One of the three solar generation facilities began commercial operation on December 31, 2015. In addition, in December 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. On July 21, 2015, the Georgia PSC approved the Company's request to build and operate an up to 46-MW solar generation facility at a U.S. Marine Corps base in Albany, Georgia. The Company subsequently determined that a 31-MW facility will be constructed on the site. On December 22, 2015, the Georgia PSC approved the Company's request to build and operate the remaining 15 MWs at a separate facility on the Fort Stewart Army base in Hinesville, Georgia. These facilities are expected to be operational by the end of 2016.

On April 7, 2015, the Georgia PSC approved the consolidation of four PPAs each with the same counterparty into two new PPAs with new biomass facilities. Under the terms of the order, the total 116 MWs from the existing four PPAs provided the capacity for two new PPAs of 58 MWs each. The new PPAs were executed on June 15, 2015 and November 23, 2015 and will begin in June 2017. See "Integrated Resource Plan" herein for additional information on renewables.

Integrated Resource Plan

See "Environmental Matters" 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.

To comply with the April 16, 2015 effective date of the MATS rule, Plant Branch Units 1, 3, and 4 (1,266 MWs), Plant Yates Units 1 through 5 (579 MWs), and Plant McManus Units 1 and 2 (122 MWs) were retired and operations were discontinued at Plant Mitchell Unit 3 (155 MWs) by April 15, 2015, and Plant Kraft Units 1 through 4 (316 MWs) were retired on October 13, 2015. The switch to natural gas as the primary fuel was completed at Plant Yates Units 6 and 7 by June 2015 and at Plant Gaston Units 1 through 4 by December 2015.

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 ending December 2022 and the amortization of the 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.

On January 29, 2016, the Company filed its triennial IRP (2016 IRP). The filing included a request to decertify Plant Mitchell Units 3, 4A, and 4B (217 MWs) and Plant Kraft Unit 1 (17 MWs) upon approval of the 2016 IRP. The 2016 IRP also reflects that the Company exercised its contractual option to sell its 33% ownership interest in the Intercession City unit (143 MWs total capacity) to Duke Energy Florida, Inc. See Note 4 to the financial statements for additional information.

In the 2016 IRP, the Company requested reclassification of the remaining net book value of Plant Mitchell Unit 3, as of its retirement date, to a regulatory asset to be amortized over a period equal to the unit's remaining useful life. The Company also requested that the Georgia PSC approve the deferral of the cost associated with materials and supplies remaining at the unit retirement dates to a regulatory asset, to be amortized over a period deemed appropriate by the Georgia PSC.

The decertification and retirement of these units are not expected to have a material impact on the Company's financial statements; however, the ultimate outcome depends on the Georgia PSC's orders in the 2016 IRP and next general base rate case.

Additionally, the 2016 IRP included a Renewable Energy Development Initiative requesting to procure up to 525 MWs of renewable resources utilizing market-based prices established through a competitive bidding process to expand the Company's existing renewable initiatives, including ASI.

A decision from the Georgia PSC on the 2016 IRP is expected in the third quarter 2016. The ultimate outcome of these matters 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 December 15, 2015, the Georgia PSC approved the Company's request to lower annual billings by approximately $350 million effective January 1, 2016. The Company's fuel cost recovery mechanism includes costs associated with a natural gas hedging program as revised and approved by the Georgia PSC allowing the use of an array of derivative instruments within a 48-month time horizon effective January 1, 2016.

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, doing business as Dalton Utilities (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) (Westinghouse and Stone & Webster, Inc., collectively, Contractor), pursuant to which the Contractor agreed to design, engineer, procure, construct, and test two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities at Plant Vogtle (Vogtle 3 and 4 Agreement).

Under the terms of the Vogtle 3 and 4 Agreement, the 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, 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%.

On December 31, 2015, Westinghouse acquired Stone & Webster, Inc. from CB&I (Acquisition). In connection with the Acquisition, Stone & Webster, Inc. changed its name to WECTEC Global Project Services Inc. (WECTEC). Certain obligations of Westinghouse and Stone & Webster, Inc. have been guaranteed by Toshiba Corporation, Westinghouse's parent company, and CB&I's The Shaw Group Inc., respectively. Subject to the consent of the DOE, in connection with the Acquisition and pursuant to the settlement agreement described below, the guarantee of The Shaw Group Inc. will be terminated. The guarantee of Toshiba Corporation remains in place. 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. Additionally, on January 13, 2016, as a result of recent credit rating downgrades of Toshiba Corporation, Westinghouse provided the Vogtle Owners with letters of credit in an aggregate amount of $900 million in accordance with, and subject to adjustment under, the terms of the Vogtle 3 and 4 Agreement.

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 may arise as construction proceeds.

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4. In addition, 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 an initial NCCR tariff of approximately $223 million effective January 1, 2011, as well as increases to the NCCR tariff of approximately $35 million, $50 million, $60 million, $27 million, and $19 million effective January 1, 2012, 2013, 2014, 2015, and 2016, respectively.

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 construction capital costs to be borne by the Company increase by 5% above the certified cost 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. In February 2013, the Company 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 (from April 2016) and the fourth quarter 2018 (from April 2017) for Plant Vogtle Units 3 and 4, respectively. In October 2013, the Georgia PSC approved a stipulation (2013 Stipulation) between the Company and the Georgia PSC Staff (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.

On April 15, 2015, the Georgia PSC issued a procedural order in connection with the twelfth VCM report, which included a requested amendment (Requested Amendment) to the Plant Vogtle Units 3 and 4 certificate to reflect the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4 (second quarter of 2019 and second quarter of 2020, respectively) as well as additional estimated Vogtle Owner's costs, of approximately $10 million per month, including property taxes, oversight costs, compliance costs, and other operational readiness costs to include the estimated Vogtle 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. Pursuant to the Georgia PSC's procedural order, the Georgia PSC deemed the Requested Amendment unnecessary and withdrawn until the completion of construction of Plant Vogtle Unit 3 consistent with the 2013 Stipulation. The Georgia PSC recognized that the certified cost and the 2013 Stipulation do not constitute a cost recovery cap. 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. Financing costs up to the certified amount will be collected through the NCCR tariff until the units are placed in service and contemplated in a general base rate case, while financing costs on any construction-related costs in excess of the $4.4 billion certified amount are expected to be recovered through AFUDC.

In 2012, the Vogtle Owners and the Contractor commenced litigation 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. The Contractor also asserted that it was entitled to extensions of the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. In May 2014, the Contractor filed an amended claim 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. In June 2015, the Contractor updated its estimated damages to an aggregate (based on the Company's ownership interest) of approximately $714 million (in 2015 dollars). The case was pending in the U.S. District Court for the Southern District of Georgia (Vogtle Construction Litigation).

On December 31, 2015, Westinghouse and the Vogtle Owners entered into a definitive settlement agreement (Contractor Settlement Agreement) to resolve disputes between the Vogtle Owners and the Contractor under the Vogtle 3 and 4 Agreement, including the Vogtle Construction Litigation. Effective December 31, 2015, the Company, acting for itself and as agent for the other Vogtle Owners, and the Contractor entered into an amendment to the Vogtle 3 and 4 Agreement to implement the Contractor Settlement Agreement. The Contractor Settlement Agreement and the related amendment to the Vogtle 3 and 4 Agreement (i) restrict the Contractor's ability to seek further increases in the contract price by clarifying and limiting the circumstances that constitute nuclear regulatory changes in law; (ii) provide for enhanced dispute resolution procedures; (iii) revise the guaranteed substantial completion dates to match the current estimated in-service dates of June 30, 2019 for Unit 3 and June 30, 2020 for Unit 4; (iv) provide that delay liquidated damages will now commence from the current estimated nuclear fuel loading date for each unit, which is December 31, 2018 for Unit 3 and December 31, 2019 for Unit 4, rather than the original guaranteed substantial completion dates under the Vogtle 3 and 4 Agreement; and (v) provide that the Company, based on its ownership interest, will pay to the Contractor and capitalize to the project cost approximately $350 million, of which approximately $120 million has been paid previously under the dispute resolution procedures of the Vogtle 3 and 4 Agreement. Further, subsequent to December 31, 2015, the Company paid approximately $121 million under the terms of the Contractor Settlement Agreement. In addition, the Contractor Settlement Agreement provides for the resolution of other open existing items relating to the scope of the project under the Vogtle 3 and 4 Agreement, including cyber security, for which costs were reflected in the Company's previously disclosed in-service cost estimate. Further, as part of the settlement and in connection with the Acquisition: (i) Westinghouse has engaged Fluor Enterprises, Inc., a subsidiary of Fluor Corporation, as a new construction subcontractor; and (ii) the Vogtle Owners, CB&I, and The Shaw Group Inc. have entered into mutual releases of any and all claims arising out of events or circumstances in connection with the construction of Plant Vogtle Units 3 and 4 that occurred on or before the date of the Contractor Settlement Agreement. On January 5, 2016, the Vogtle Construction Litigation was dismissed with prejudice.

On January 21, 2016, the Company submitted the Contractor Settlement Agreement and the related amendment to the Vogtle 3 and 4 Agreement to the Georgia PSC for its review. On February 2, 2016, the Georgia PSC ordered the Company to file supplemental information by April 5, 2016 in support of the Contractor Settlement Agreement and the Company's position that all construction costs to date have been prudently incurred and that the current estimated in-service capital cost and schedule are reasonable. Following the Company's filing under the order, the Staff will conduct a review of all costs incurred related to Plant Vogtle Units 3 and 4, the schedule for completion of Plant Vogtle Units 3 and 4, and the Contractor Settlement Agreement and the Staff is authorized to engage in related settlement discussions with the Company and any intervenors.

The order provides that the Staff is required to report to the Georgia PSC by October 5, 2016 with respect to the status of its review and any settlement-related negotiations. If a settlement with the Staff is reached with respect to costs of Plant Vogtle Units 3 and 4, the Georgia PSC will then conduct a hearing to consider whether to approve that settlement. If a settlement with the Staff is not reached, the Georgia PSC will determine how to proceed, including (i) modifying the 2013 Stipulation, (ii) directing the Company to file a request for an amendment to the certificate for Plant Vogtle Units 3 and 4, (iii) issuing a scheduling order to address remaining disputed issues, or (iv) taking any other option within its authority.

The Georgia PSC has approved thirteen VCM reports covering the periods through June 30, 2015, including construction capital costs incurred, which through that date totaled $3.1 billion. On February 26, 2016, the Company filed its fourteenth VCM report with the Georgia PSC covering the period from July 1 through December 31, 2015. The fourteenth VCM report does not include a requested amendment to the certified cost of Plant Vogtle Units 3 and 4. The Company is requesting approval of $160 million of construction capital costs incurred during that period. The Company anticipates to incur average financing costs of approximately $27 million per month from January 2016 until Plant Vogtle Units 3 and 4 are placed in service. The updated in-service capital cost forecast is $5.44 billion and includes costs related to the Contractor Settlement Agreement. Estimated financing costs during the construction period total approximately $2.4 billion. The Company's CWIP balance for Plant Vogtle Units 3 and 4 was approximately $3.6 billion as of December 31, 2015.

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 may 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 challenges with Contractor performance including 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.

Future claims by the Contractor or the Company (on behalf of the Vogtle Owners) could arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the Vogtle 3 and 4 Agreement and, under the enhanced dispute resolution procedures, may be resolved through litigation after the completion of nuclear fuel load for both units.

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

Income Tax Matters

Bonus Depreciation

On December 18, 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. Bonus depreciation was extended for qualified property placed in service over the next five years. The PATH Act allows for 50% bonus depreciation for 2015, 2016, and 2017; 40% bonus depreciation for 2018; and 30% bonus depreciation for 2019 and certain long-lived assets placed in service in 2020. The extension of 50% bonus depreciation is expected to result in approximately $220 million of positive cash flows for the 2015 tax year and approximately $310 million for the 2016 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.

Asset Retirement Obligations

AROs are computed as the fair value of the estimated 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. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities.

The liability for AROs primarily 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, and facilities that are subject to the CCR Rule, principally ash ponds. In addition, the Company has retirement obligations related to various landfill sites, 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 previously recorded AROs as a result of state requirements in Georgia which closely align with the requirements of the CCR Rule discussed above. The cost estimates are based on information using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule requirements for closure in place or by other methods. As further analysis is performed, including evaluation of the expected method of compliance, refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, and the determination of timing, including the potential for closing ash ponds prior to the end of their currently anticipated useful life, the Company expects to continue to periodically update these estimates.

Given the significant judgment involved in estimating AROs, the Company considers the liabilities for AROs to be critical accounting estimates.

See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" and "Nuclear Decommissioning" for additional information.

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 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 pension and other 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. For purposes of determining its liability related to the pension and other postretirement benefit plans, the Company discounts the future related cash flows using a single-point discount rate for each plan developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments. For 2015 and prior years, the Company computed the interest cost component of its net periodic pension and other postretirement benefit plan expense using the same single-point discount rate. For 2016, the Company has adopted a full yield curve approach for calculating the interest cost component whereby the discount rate for each year is applied to the liability for that specific year. As a result, the interest cost component of net periodic pension and other postretirement benefit plan expense will decrease by approximately $35 million in 2016.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $10 million or less change in total annual benefit expense and a $141 million or less change in projected obligations.

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 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 results of operations, cash flows, or financial condition.

Recently Issued Accounting Standards

The Financial Accounting Standards Board's (FASB) ASC 606, *Revenue from Contracts with Customers*, revises the accounting for revenue recognition effective for fiscal years beginning after December 15, 2017. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

On April 7, 2015, the FASB issued Accounting Standards Update (ASU) No. 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* (ASU 2015-03). ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability and is effective for fiscal years beginning after December 15, 2015. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The new guidance resulted in an adjustment to the presentation of debt issuance costs as an offset to the related debt balances primarily in long-term debt totaling $124 million as of December 31, 2014. These debt issuance costs were previously presented within other deferred charges and assets. Other than the reclassification, the adoption of ASU 2015-03 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Notes 6 and 10 to the financial statements for disclosures impacted by ASU 2015-03.

On May 1, 2015, the FASB issued ASU No. 2015-07, *Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* (ASU 2015-07), effective for fiscal years beginning after December 15, 2015. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The amendments in ASU 2015-07 remove the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. In addition, the amendments remove the requirement to make certain disclosures for all investments that are eligible to be measured at fair value using the net asset value per share practical expedient regardless of whether the practical expedient was used. In accordance with ASU 2015-07, previously reported amounts have been conformed to the current presentation. The adoption of ASU 2015-07 had no impact on the results of operations, cash flows, or financial condition of the Company. See Notes 2 and 10 to the financial statements for disclosures impacted by ASU 2015-07.

On November 20, 2015, the FASB issued ASU No. 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes* (ASU 2015-17), which simplifies the presentation of deferred income taxes. ASU 2015-17 requires deferred tax assets and liabilities to be presented as non-current in a classified balance sheet and is effective for fiscal years beginning after December 15, 2016, including interim periods within that reporting period. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. Prior to the adoption of ASU 2015-17, all deferred income tax assets and liabilities were required to be separated into current and non-current amounts. The new guidance resulted in a reclassification from prepaid income taxes of $34 million to non-current accumulated deferred income taxes in the Company's December 31, 2014 balance sheet. Other than the reclassification, the adoption of ASU 2015-17 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Note 5 to the financial statements for disclosures impacted by ASU 2015-17.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2015. 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 maintain existing facilities, 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 2016 through 2018, 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 modifications to 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 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 nuclear decommissioning trust funds decreased in value as of December 31, 2015 as compared to December 31, 2014. No contributions to the qualified pension plan were made for the year ended December 31, 2015, and no mandatory contributions to the qualified pension plan are anticipated during 2016. The Company funded approximately $5 million to its nuclear decommissioning trust funds in 2015. 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 $2.5 billion in 2015, an increase of $154 million from 2014, primarily due to increased fuel cost recovery, partially offset by the timing of vendor payments. Net cash provided from operating activities totaled $2.4 billion in 2014, a decrease of $403 million from 2013, primarily due to the timing of rate recovery for fuel and storm restoration costs, partially offset by higher retail operating revenues and lower fuel inventory additions.

Net cash used for investing activities totaled $1.9 billion, $2.2 billion, and $1.9 billion in 2015, 2014, and 2013, 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 $530 million, $163 million, and $891 million for 2015, 2014, and 2013, respectively. The increase in cash used in 2015 compared to 2014 was primarily due to the redemption and maturity of senior notes in 2015. 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. 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 2015 included an increase of $1.8 billion in total property, plant, and equipment due to gross property additions as described above, an increase in other regulatory assets, deferred of $399 million primarily related to AROs and deferred plant retirement costs, an increase of $615 million in long-term debt, and an increase of $661 million in AROs. See Note 1 to the financial statements for additional information.

The Company's ratio of common equity to total capitalization, including short-term debt, was 49.9% in 2015 and 50.4% in 2014. 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, external 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.

In addition, the Company may make borrowings through a loan guarantee agreement (Loan Guarantee Agreement) between the Company and the DOE, the proceeds of which may 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). Under the Loan Guarantee Agreement, the DOE agreed to guarantee borrowings of up to $3.46 billion (not to exceed 70% of Eligible Project Costs) to be made by the Company under a multi-advance credit facility (FFB Credit Facility) among the Company, the DOE, and the FFB. Eligible Project Costs incurred through December 31, 2015 would allow for borrowings of up to $2.3 billion under the FFB Credit Facility, of which the Company has borrowed $2.2 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.

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, 2015, the Company's current liabilities exceeded current assets by $772 million primarily due to long-term debt that is due in one year. The Company intends to utilize operating cash flows, as well as FFB borrowings, commercial paper, lines of credit, bank notes, and external securities issuances, as market conditions permit, and equity contributions from Southern Company to fund its short-term capital needs. 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, 2015, the Company had approximately $67 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2015 were $1.75 billion of which $1.73 billion was unused. These credit arrangements expire in 2020.

In August 2015, the Company amended and restated its multi-year credit arrangement, which, among other things, extended the maturity date from 2018 to 2020. The Company increased its borrowing ability by $150 million under its facility maturing in 2020 and terminated its aggregate $150 million facilities maturing in 2016.

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

This bank credit arrangement contains a covenant that limits debt levels and contains a cross acceleration provision to other indebtedness (including guarantee obligations) of the Company. Such cross acceleration provision to other indebtedness would trigger an event of default if the Company defaulted on indebtedness, the payment of which was then accelerated. The Company is currently in compliance with this covenant. This bank credit arrangement does not contain a material adverse change clause at the time of borrowing.

Subject to applicable market conditions, the Company expects to renew or replace this credit arrangement, as needed, prior to expiration. In connection therewith, the Company may extend the maturity date and/or increase or decrease the lending commitments thereunder.

A portion of the unused credit with banks is allocated to provide liquidity support to the Company's 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, 2015 was approximately $872 million. In addition, at December 31, 2015, the Company had $69 million of fixed rate pollution control revenue bonds outstanding that were required to be reoffered within the next 12 months.

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 (*)		
	Amount Outstanding	Weighted Average Interest Rate	Average Amount Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		(in millions)		(in millions)
December 31, 2015:					
Commercial paper	**$ 158**	**0.6%**	**$ 234**	**0.3%**	**$ 678**
Short-term bank debt	**—**	**—%**	**62**	**0.8%**	**250**
Total	**$ 158**	**0.6%**	**$ 296**	**0.4%**	
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 %	

(*) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2015, 2014, and 2013.

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 operating cash flows.

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.

Senior Notes

In April 2015, the Company redeemed $125 million aggregate principal amount of its Series Y 5.80% Senior Notes due April 15, 2035.

In August 2015, the Company's $400 million aggregate principal amount of Series 2012C 0.75% Senior Notes matured.

In November 2015, the Company's $400 million aggregate principal amount of Series 2012D 0.625% Senior Notes matured.

In December 2015, the Company issued $500 million aggregate principal amount of Series 2015A 1.95% Senior Notes due December 1, 2018. The proceeds were used to repay at maturity $250 million aggregate principal amount of the Company's Series Z 5.25% Senior Notes due December 15, 2015, to repay a portion of the Company's short-term indebtedness, and for general corporate purposes, including the Company's continuous construction program.

Pollution Control Revenue Bonds

In April 2015, the Company purchased and held $65 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), Second Series 2008. The Company reoffered these bonds to the public in May 2015.

In May 2015, the Company reoffered to the public $104.6 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 2013, which had been previously purchased and held by the Company since 2013.

In July 2015, $97.925 million aggregate principal amount of the Development Authority of Putnam County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Branch Project), First Series 1996, First Series 1997, Second Series 1997, and First Series 1998 were redeemed.

In August 2015, in connection with optional tenders, the Company repurchased and reoffered to the public $94.6 million aggregate principal amount of Development Authority of Bartow County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Bowen Project), First Series 2009 and $10 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 2013.

In November 2015, the Company reoffered to the public $89.2 million aggregate principal amount of Development Authority of Monroe County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Scherer Project), Second Series 2009 and $46 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 1996, which had been previously repurchased and held by the Company since 2010.

DOE Loan Guarantee Borrowings

In June and December 2015, the Company made additional borrowings under the FFB Credit Facility in an aggregate principal amount of $600 million and $400 million, respectively. The interest rate applicable to the $600 million principal amount is 3.283% and the interest rate applicable to the $400 million principal amount is 3.072%, both for an interest period that extends to the final maturity date of February 20, 2044. The proceeds were used to reimburse the Company for Eligible Project Costs relating to the construction of Plant Vogtle Units 3 and 4.

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 March 2015, the Company entered into a $250 million aggregate principal amount three-month floating rate bank loan bearing interest based on one-month LIBOR. The proceeds were used for working capital and other general corporate purposes and the loan was repaid at maturity.

In December 2015, 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 $500 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, transmission, and construction of new generation at Plant Vogtle Units 3 and 4.

The maximum potential collateral requirements under these contracts at December 31, 2015 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB- and/or Baa3	$ 102
Below BBB- and/or Baa3	$ 1,361

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, a credit rating downgrade could impact the ability of the Company to access capital markets and would be likely to impact the cost at which it does so.

On August 17, 2015, S&P downgraded the consolidated long-term issuer rating of Southern Company (including the Company) to A- from A. S&P revised its credit rating outlook from negative to stable. Separately, on August 24, 2015, S&P revised its credit rating outlook from stable to negative following the announcement of the proposed merger of a wholly-owned direct subsidiary of Southern Company with and into AGL Resources Inc.

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 $1.8 billion of long-term variable interest rate exposure at January 1, 2016 was 1.32%. 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 $18 million at January 1, 2016. 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, 2015 when compared to the December 31, 2014 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:

	2015 Changes	2014 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (20)**	$ (16)
Contracts realized or settled:		
Swaps realized or settled	**2**	2
Options realized or settled	**18**	8
Current period changes(*):		
Swaps	**—**	(1)
Options	**(13)**	(13)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (13)**	$ (20)

(*) 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:

	2015	2014
	mmBtu Volume	
	(in millions)	
Commodity – Natural gas swaps	**—**	4
Commodity – Natural gas options	**50**	42
Total hedge volume	**50**	46

There were no swaps outstanding as of December 31, 2015. The weighted average swap contract cost above market prices was $0.68 per mmBtu as of December 31, 2014. 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, 2015 and 2014, 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 had a time horizon up to 24 months. On December 15, 2015, the Georgia PSC approved changes to the Company's hedging program allowing it to use an array of derivative instruments within a 48-month time horizon effective January 1, 2016. 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, 2015 were as follows:

	Fair Value Measurements December 31, 2015		
	Total	Maturity	
	Fair Value	Year 1	Years 2&3
		(in millions)	
Level 1	$ —	$ —	$ —
Level 2	(13)	(10)	(3)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$ (13)	$ (10)	$ (3)

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 total $2.5 billion for 2016, $2.4 billion for 2017, and $2.1 billion for 2018. These amounts include expenditures of approximately $0.6 billion, $0.7 billion, and $0.4 billion to continue construction on Plant Vogtle Units 3 and 4 in 2016, 2017, and 2018, respectively. These amounts also include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. Estimated capital expenditures to comply with environmental statutes and regulations included in these amounts are $0.3 billion, $0.2 billion, and $0.2 billion for 2016, 2017, and 2018, respectively. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's final rules and guidelines or subsequently approved state plans 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" and "– Global Climate Issues" herein for additional information.

The Company also anticipates costs associated with closure in place or by other methods, and ground water monitoring of ash ponds in accordance with the CCR Rule, which are not reflected in the capital expenditures above as these costs are associated with the Company's ARO liabilities. These costs, which could change as the Company continues to refine its assumptions underlying the cost estimates and evaluate the method and timing of compliance, are estimated to be $0.2 billion, $0.2 billion, and $0.1 billion for the years 2016, 2017, and 2018, respectively. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" 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, other purchase commitments, and trusts 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

	2016	2017-2018	2019-2020	After 2020	Total
			(in millions)		
Long-term debt[a] —					
Principal	$ 704	$ 1,197	$ 539	$ 7,833	$ 10,273
Interest	382	715	617	5,205	6,919
Preferred and preference stock dividends[b]	17	35	35	—	87
Financial derivative obligations[c]	12	3	—	—	15
Operating leases[d]	23	30	15	16	84
Capital leases[d]	6	14	15	—	35
Purchase commitments —					
Capital[e]	2,385	4,113	—	—	6,498
Fuel[f]	1,423	1,789	879	6,635	10,726
Purchased power[g]	337	633	544	2,803	4,317
Other[h]	66	144	148	170	528
Trusts —					
Nuclear decommissioning[i]	5	11	11	104	131
Pension and other postretirement benefit plans[j]	42	78	—	—	120
Total	$ 5,402	$ 8,762	$ 2,803	$ 22,766	$ 39,733

(a) All amounts are reflected based on final maturity dates except for amounts related to FFB borrowings. As it relates to the FFB borrowings, the final maturity date is February 20, 2044; however, principal amortization is reflected beginning in 2020. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information. The Company plans to continue, when economically feasible, to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2016, 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 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 in "Fuel" and "Other," respectively. At December 31, 2015, 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, 2015.

(g) Estimated minimum long-term obligations for various PPA purchases from gas-fired, biomass, and wind-powered facilities. Includes a total of $304 million of biomass PPAs that 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" herein 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 2015 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, pending or potential litigation matters, access to sources of capital, projections for the qualified pension plan, postretirement benefit plans, and nuclear decommissioning trust fund contributions, financing activities, completion dates of construction projects and changing fuel sources, filings with state and federal regulatory authorities, impact of the PATH Act, 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 regulating emissions, discharges, and disposal to air, water, and land, 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, without limitation, 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 environmental performance standards 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, and 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 (or sell excess 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.

[This page intentionally left blank]

STATEMENTS OF INCOME
For the Years Ended December 31, 2015, 2014, and 2013
Georgia Power Company 2015 Annual Report

	2015	2014	2013
		(in millions)	
Operating Revenues:			
Retail revenues	**$ 7,727**	$ 8,240	$ 7,620
Wholesale revenues, non-affiliates	**215**	335	281
Wholesale revenues, affiliates	**20**	42	20
Other revenues	**364**	371	353
Total operating revenues	**8,326**	8,988	8,274
Operating Expenses:			
Fuel	**2,033**	2,547	2,307
Purchased power, non-affiliates	**289**	287	224
Purchased power, affiliates	**575**	701	660
Other operations and maintenance	**1,844**	1,902	1,654
Depreciation and amortization	**846**	846	807
Taxes other than income taxes	**391**	409	382
Total operating expenses	**5,978**	6,692	6,034
Operating Income	**2,348**	2,296	2,240
Other Income and (Expense):			
Interest expense, net of amounts capitalized	**(363)**	(348)	(361)
Other income (expense), net	**61**	23	35
Total other income and (expense)	**(302)**	(325)	(326)
Earnings Before Income Taxes	**2,046**	1,971	1,914
Income taxes	**769**	729	723
Net Income	**1,277**	1,242	1,191
Dividends on Preferred and Preference Stock	**17**	17	17
Net Income After Dividends on Preferred and Preference Stock	**$ 1,260**	$ 1,225	$ 1,174

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2015, 2014, and 2013
Georgia Power Company 2015 Annual Report

	2015	2014	2013
		(in millions)	
Net Income	**$ 1,277**	$ 1,242	$ 1,191
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(6), $(3), and $-, respectively	**(9)**	(5)	—
Reclassification adjustment for amounts included in net income, net of tax of $1, $1, and $1, respectively	**2**	2	2
Total other comprehensive income (loss)	**(7)**	(3)	2
Comprehensive Income	**$ 1,270**	$ 1,239	$ 1,193

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2015, 2014, and 2013
Georgia Power Company 2015 Annual Report

	2015	2014	2013
		(in millions)	
Operating Activities:			
Net income	**$ 1,277**	$ 1,242	$ 1,191
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	**1,029**	1,019	979
Deferred income taxes	**173**	352	476
Allowance for equity funds used during construction	**(40)**	(45)	(30)
Retail fuel cost over-recovery — long-term	**106**	(44)	(123)
Pension, postretirement, and other employee benefits	**40**	19	66
Pension and postretirement funding	**(7)**	(156)	(8)
Other, net	**(59)**	39	38
Changes in certain current assets and liabilities —			
-Receivables	**187**	(248)	(58)
-Fossil fuel stock	**37**	303	250
-Prepaid income taxes	**89**	(216)	(17)
-Other current assets	**(62)**	(37)	40
-Accounts payable	**(259)**	16	67
-Accrued taxes	**25**	17	(14)
-Accrued compensation	**(17)**	62	(37)
-Retail fuel cost over-recovery — short-term	**10**	(14)	(49)
-Other current liabilities	**(12)**	54	(5)
Net cash provided from operating activities	**2,517**	2,363	2,766
Investing Activities:			
Property additions	**(2,091)**	(2,023)	(1,743)
Investment in restricted cash from pollution control bonds	**—**	—	(89)
Distribution of restricted cash from pollution control bonds	**—**	—	89
Nuclear decommissioning trust fund purchases	**(985)**	(671)	(706)
Nuclear decommissioning trust fund sales	**980**	669	705
Cost of removal, net of salvage	**(71)**	(65)	(59)
Change in construction payables, net of joint owner portion	**217**	(54)	(67)
Prepaid long-term service agreements	**(66)**	(70)	(18)
Sale of property	**70**	7	7
Other investing activities	**2**	1	(9)
Net cash used for investing activities	**(1,944)**	(2,206)	(1,890)
Financing Activities:			
Increase (decrease) in notes payable, net	**2**	(891)	1,047
Proceeds —			
Capital contributions from parent company	**62**	549	37
Pollution control revenue bonds issuances and remarketings	**409**	40	194
Senior notes issuances	**500**	—	850
FFB loan	**1,000**	1,200	—
Short-term borrowings	**250**	—	—
Redemptions and repurchases —			
Pollution control revenue bonds	**(268)**	(37)	(298)
Senior notes	**(1,175)**	—	(1,775)
Short-term borrowings	**(250)**	—	—
Payment of preferred and preference stock dividends	**(17)**	(17)	(17)
Payment of common stock dividends	**(1,034)**	(954)	(907)
FFB loan issuance costs	**—**	(49)	(5)
Other financing activities	**(9)**	(4)	(17)
Net cash used for financing activities	**(530)**	(163)	(891)
Net Change in Cash and Cash Equivalents	**43**	(6)	(15)
Cash and Cash Equivalents at Beginning of Year	**24**	30	45
Cash and Cash Equivalents at End of Year	**$ 67**	$ 24	$ 30
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $16, $18, and $14 capitalized, respectively)	**$ 353**	$ 319	$ 344
Income taxes (net of refunds)	**506**	507	298
Noncash transactions —			
Accrued property additions at year-end	**387**	154	208
Capital lease obligation	**149**	—	—

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

BALANCE SHEETS
At December 31, 2015 and 2014
Georgia Power Company 2015 Annual Report

Assets	**2015**	2014
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 67**	$ 24
Receivables —		
Customer accounts receivable	**541**	553
Unbilled revenues	**188**	201
Joint owner accounts receivable	**227**	121
Other accounts and notes receivable	**57**	61
Affiliated companies	**18**	18
Accumulated provision for uncollectible accounts	**(2)**	(6)
Income taxes receivable, current	**114**	—
Fossil fuel stock, at average cost	**402**	439
Materials and supplies, at average cost	**449**	438
Vacation pay	**91**	91
Prepaid income taxes	**156**	244
Other regulatory assets, current	**123**	136
Other current assets	**92**	74
Total current assets	**2,523**	2,394
Property, Plant, and Equipment:		
In service	**31,841**	31,083
Less accumulated provision for depreciation	**10,903**	11,222
Plant in service, net of depreciation	**20,938**	19,861
Other utility plant, net	**171**	211
Nuclear fuel, at amortized cost	**572**	563
Construction work in progress	**4,775**	4,031
Total property, plant, and equipment	**26,456**	24,666
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**64**	58
Nuclear decommissioning trusts, at fair value	**775**	789
Miscellaneous property and investments	**43**	38
Total other property and investments	**882**	885
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**679**	698
Deferred under recovered regulatory clause revenues	**—**	197
Other regulatory assets, deferred	**2,152**	1,753
Other deferred charges and assets	**173**	279
Total deferred charges and other assets	**3,004**	2,927
Total Assets	**$ 32,865**	$ 30,872

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

BALANCE SHEETS
At December 31, 2015 and 2014
Georgia Power Company 2015 Annual Report

Liabilities and Stockholder's Equity	2015	2014
	(in millions)	
Current Liabilities:		
Securities due within one year	$ 712	$ 1,150
Notes payable	158	156
Accounts payable —		
Affiliated	411	451
Other	750	555
Customer deposits	264	253
Accrued taxes —		
Accrued income taxes	12	—
Other accrued taxes	325	332
Accrued interest	99	96
Accrued vacation pay	62	63
Accrued compensation	142	153
Asset retirement obligations, current	179	32
Liabilities from risk management activities	12	32
Other regulatory liabilities, current	16	21
Over recovered regulatory clause revenues, current	10	—
Other current liabilities	143	172
Total current liabilities	3,295	3,466
Long-Term Debt (See accompanying statements)	9,616	8,563
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	5,627	5,474
Deferred credits related to income taxes	105	106
Accumulated deferred investment tax credits	204	196
Employee benefit obligations	949	903
Asset retirement obligations, deferred	1,737	1,223
Other cost of removal obligations	16	46
Other deferred credits and liabilities	331	208
Total deferred credits and other liabilities	8,969	8,156
Total Liabilities	21,880	20,185
Preferred Stock (See accompanying statements)	45	45
Preference Stock (See accompanying statements)	221	221
Common Stockholder's Equity (See accompanying statements)	10,719	10,421
Total Liabilities and Stockholder's Equity	$ 32,865	$ 30,872
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2015 and 2014
Georgia Power Company 2015 Annual Report

		2015		2014	2015	2014
			(in millions)		*(percent of total)*	
Long-Term Debt:						
Long-term notes payable —						
Variable rates (0.76% to 0.83% at 1/1/16) due 2016	**$**	**450**	$	450		
0.625% to 5.25% due 2015		**—**		1,050		
3.00% due 2016		**250**		250		
5.70% due 2017		**450**		450		
1.95% to 5.40% due 2018		**747**		250		
4.25% due 2019		**502**		500		
2.85% to 5.95% due 2022-2043		**3,850**		3,975		
Total long-term notes payable		**6,249**		6,925		
Other long-term debt —						
Pollution control revenue bonds —						
0.85% to 4.00% due 2022-2049		**952**		818		
Variable rates (0.03% to 0.04% at 1/1/15) due 2015		**—**		98		
Variable rate (0.22% at 1/1/16) due 2016		**4**		4		
Variable rates (0.10% to 0.27% at 1/1/16) due 2022-2053		**868**		763		
FFB loans —						
3.00% to 3.86% due 2020		**37**		20		
3.00% to 3.86% due 2021-2044		**2,163**		1,180		
Total other long-term debt		**4,024**		2,883		
Capitalized lease obligations		**183**		40		
Unamortized debt premium (discount), net		**(10)**		(11)		
Unamortized debt issuance expense		**(118)**		(124)		
Total long-term debt (annual interest requirement — $382 million)		**10,328**		9,713		
Less amount due within one year		**712**		1,150		
Long-term debt excluding amount due within one year		**9,616**		8,563	**46.7%**	44.5%
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 — $17 million)		**266**		266	**1.3**	1.4
Common Stockholder's Equity:						
Common stock, without par value —						
Authorized — 20,000,000 shares						
Outstanding — 9,261,500 shares		**398**		398		
Paid-in capital		**6,275**		6,196		
Retained earnings		**4,061**		3,835		
Accumulated other comprehensive loss		**(15)**		(8)		
Total common stockholder's equity		**10,719**		10,421	**52.0**	54.1
Total Capitalization	**$**	**20,601**	$	19,250	**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, 2015, 2014, and 2013
Georgia Power Company 2015 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, 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**
Net income after dividends on preferred and preference stock	**—**	**—**	**—**	**1,260**	**—**	**1,260**
Capital contributions from parent company	**—**	**—**	**79**	**—**	**—**	**79**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**(7)**	**(7)**
Cash dividends on common stock	**—**	**—**	**—**	**(1,034)**	**—**	**(1,034)**
Balance at December 31, 2015	**9**	**$ 398**	**$ 6,275**	**$ 4,061**	**$ (15)**	**$ 10,719**

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

Index to the Notes to Financial Statements

Note		Page
1	Summary of Significant Accounting Polices	41
2	Retirement Benefits	49
3	Contingencies and Regulatory Matters	59
4	Joint Ownership Agreements	64
5	Income Taxes	65
6	Financing	67
7	Commitments	71
8	Stock Compensation	73
9	Nuclear Insurance	75
10	Fair Value Measurements	76
11	Derivatives	78
12	Quarterly Financial Information (Unaudited)	82

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Georgia Power Company (the Company) is a wholly-owned subsidiary of 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 provides 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 and for other electric services. 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. As such, the Company's financial statements reflect the effects of rate regulation in accordance with GAAP and comply 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.

In June 2015, the Company identified an error affecting the billing to a small number of large commercial and industrial customers under a rate plan allowing for variable demand-driven pricing from January 1, 2013 to June 30, 2015. In the second quarter 2015, the Company recorded an out of period adjustment of approximately $75 million to decrease retail revenues, resulting in a decrease to net income of approximately $47 million. The Company evaluated the effects of this error on the interim and annual periods that included the billing error, as well as the current period. Based on an analysis of qualitative and quantitative factors, the Company determined the error was not material to any affected period and, therefore, an amendment of previously filed financial statements was not required.

Recently Issued Accounting Standards

The Financial Accounting Standards Board's (FASB) ASC 606, *Revenue from Contracts with Customers*, revises the accounting for revenue recognition effective for fiscal years beginning after December 15, 2017. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

On April 7, 2015, the FASB issued Accounting Standards Update (ASU) No. 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* (ASU 2015-03). ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability and is effective for fiscal years beginning after December 15, 2015. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The new guidance resulted in an adjustment to the presentation of debt issuance costs as an offset to the related debt balances primarily in long-term debt totaling $124 million as of December 31, 2014. These debt issuance costs were previously presented within other deferred charges and assets. Other than the reclassification, the adoption of ASU 2015-03 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Notes 6 and 10 for disclosures impacted by ASU 2015-03.

On May 1, 2015, the FASB issued ASU No. 2015-07, *Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* (ASU 2015-07), effective for fiscal years beginning after December 15, 2015. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The amendments in ASU 2015-07 remove the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. In addition, the amendments remove the requirement to make certain disclosures for all investments that are eligible to be measured at fair value using the net asset value per share practical expedient regardless of whether the practical expedient was used. In accordance with ASU 2015-07, previously reported amounts have been conformed to the current presentation. The adoption of ASU 2015-07 had no impact on the results of operations, cash flows, or financial condition of the

Company. See Notes 2 and 10 for disclosures impacted by ASU 2015-07.

On November 20, 2015, the FASB issued ASU No. 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes* (ASU 2015-17), which simplifies the presentation of deferred income taxes. ASU 2015-17 requires deferred tax assets and liabilities to be presented as non-current in a classified balance sheet and is effective for fiscal years beginning after December 15, 2016, including interim periods within that reporting period. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. Prior to the adoption of ASU 2015-17, all deferred income tax assets and liabilities were required to be separated into current and non-current amounts. The new guidance resulted in a reclassification from prepaid income taxes of $34 million to non-current accumulated deferred income taxes in the Company's December 31, 2014 balance sheet. Other than the reclassification, the adoption of ASU 2015-17 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Note 5 for disclosures impacted by ASU 2015-17.

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 $585 million in 2015, $555 million in 2014, and $504 million in 2013. 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 $681 million in 2015, $643 million in 2014, and $555 million in 2013.

The Company has entered into several PPAs with Southern Power for capacity and energy. Expenses associated with these PPAs were $179 million, $144 million, and $136 million in 2015, 2014, and 2013, 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, 2015 and 2014. 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 $12 million in 2015, $9 million in 2014, and $10 million in 2013. 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 2015, 2014, or 2013.

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

Regulatory Assets and Liabilities

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

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

	2015	2014	Note
	(in millions)		
Retiree benefit plans	**$ 1,307**	$ 1,325	(a, j)
Deferred income tax charges	**653**	668	(b, j)
Loss on reacquired debt	**150**	163	(c, j)
Asset retirement obligations	**411**	108	(b, j)
Vacation pay	**91**	91	(d, j)
Cancelled construction projects	**56**	67	(e)
Remaining net book value of retired assets	**171**	29	(f)
Storm damage reserves	**92**	98	(g)
Other regulatory assets	**140**	153	(h)
Other cost of removal obligations	**(31)**	(60)	(b)
Deferred income tax credits	**(105)**	(106)	(b, j)
Other regulatory liabilities	**(2)**	(7)	(i, j)
Total regulatory assets (liabilities), net	**$ 2,933**	$ 2,529	

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

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

(b) Asset retirement and other cost of removal obligations and deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 70 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities. At December 31, 2015, other cost of removal obligations included $14 million that will be amortized over the twelve months ending December 31, 2016 in accordance with the three-year amortization period approved in the Company's 2013 ARP.

(c) 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.

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

(e) 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.

(f) Amortized as approved by the Georgia PSC over periods not exceeding 10 years or through 2024. Amortization of obsolete inventories will be determined by the Georgia PSC in the 2016 base rate case.

(g) Recorded and recovered or amortized as approved by the Georgia PSC over periods generally not exceeding six years or through 2019.

(h) Comprised of several components including deferred nuclear outages, environmental remediation, Medicare subsidy deferred income tax charges, fuel hedging losses, building lease, and other miscellaneous assets. These costs are recorded and recovered or amortized as approved by the Georgia PSC over periods generally not exceeding 12 years or through 2022.

(i) Comprised primarily of fuel-hedging gains, which upon final settlement are refunded through the Company's fuel cost recovery mechanism.

(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 and other credits are recognized in the period in which the credits are claimed on the state income tax return. The Company had state investment and other tax credit carryforwards totaling $318 million, which will expire between 2018 and 2026 and are expected to be fully utilized by 2022.

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:

	2015	2014
	(in millions)	
Generation	**$ 15,386**	$ 15,201
Transmission	**5,355**	5,086
Distribution	**9,151**	8,913
General	**1,921**	1,855
Plant acquisition adjustment	**28**	28
Total plant in service	**$ 31,841**	$ 31,083

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 2015, 2.7% in 2014, and 3.0% in 2013. 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.

Under the terms of the Company's Alternate Rate Plan for the years 2011 through 2013 (2010 ARP) and the 2013 ARP, the Company amortized approximately $31 million in 2013 and $14 million in each of 2014 and 2015 of its remaining regulatory liability related to other cost of removal obligations.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations (ARO) are computed as the present value of the estimated 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. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities. 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 primarily relates to the Company's ash ponds, landfills, and gypsum cells that are subject to the Disposal of Coal Combustion Residuals from Electric Utilities final rule published by the EPA on April 17, 2015 (CCR Rule). In addition, the Company has retirement obligations related to decommissioning of the Company's nuclear facilities, which include the Company's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2, 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:

	2015	2014
	(in millions)	
Balance at beginning of year	**$ 1,255**	$ 1,222
Liabilities incurred	**6**	9
Liabilities settled	**(30)**	(12)
Accretion	**56**	53
Cash flow revisions	**629**	(17)
Balance at end of year	**$ 1,916**	$ 1,255

The increase in cash flow revisions in 2015 is primarily related to changes to the Company's ash ponds, landfill, and gypsum cell ARO closure dollar and timing estimates associated with the CCR Rule and revisions to the nuclear decommissioning AROs based on the latest decommissioning study. In preparation for the Company's next rate case, and as a part of the Company's three-year ARO update cycle, new closure estimates were developed for ash ponds, landfills, gypsum cells, nuclear decommissioning, and asbestos AROs. The cost estimates for AROs related to the CCR Rule are based on information as of December 31, 2015 using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule requirements for closure in place or by other methods. As further analysis is performed, including evaluation of the expected method of compliance, refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, and the determination of timing, including the potential for closing ash ponds prior to the end of their currently anticipated useful life, the Company expects to continue to periodically update these estimates.

The 2014 decrease in cash flow revisions is primarily related to settled AROs for asbestos remediation.

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, 2015 and 2014, approximately $76 million and $51 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 $78 million and $52 million at December 31, 2015 and 2014, 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, 2015, investment securities in the Funds totaled $775 million, consisting of equity securities of $296 million, debt securities of $463 million, and $16 million of other securities. 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. 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 $980 million, $669 million, and $705 million in 2015, 2014, and 2013, respectively, all of which were reinvested. For 2015, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $3 million, which included $26 million related to unrealized losses on securities held in the Funds at December 31, 2015. For 2014, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $44 million, which included 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, which included $34 million related to unrealized gains on securities held in the Funds at December 31, 2013. 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 2015. The site study costs and external trust funds for decommissioning as of December 31, 2015 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	2075	2079
	(in millions)	
Site study costs:		
Radiated structures	$ 678	$ 568
Spent fuel management	160	147
Non-radiated structures	64	89
Total site study costs	$ 902	$ 804
External trust funds	$ 487	$ 288

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 2015, 2014, and 2013, the average AFUDC rates were 6.5%, 5.6%, and 5.3%, respectively, and AFUDC capitalized was $56 million, $62 million, and $44 million, respectively. AFUDC, net of income taxes, was 3.9%, 4.6%, and 3.3% of net income after dividends on preferred and preference stock for 2015, 2014, and 2013, 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, 2015 and December 31, 2014, the balance in the regulatory asset related to storm damage was $92 million and $98 million, respectively, with approximately $30 million included in other regulatory assets, current for both years and approximately $62 million and $68 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 earnings.

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 earnings. As of December 31, 2015, the balance of the environmental remediation liability was $29 million, with approximately $2 million included in other regulatory assets, current and approximately $30 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 on the balance sheets (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. Cash flows from derivatives are classified on the statement of cash flows in the same category as the hedged item. 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, 2015.

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

Comprehensive Income

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

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2015, and no mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2016. 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, 2016, other postretirement trust contributions are expected to total approximately $14 million.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the net periodic costs for the pension and other postretirement benefit plans for the following year and the benefit obligations as of the measurement date are presented below.

Assumptions used to determine net periodic costs:	**2015**	2014	2013
Pension plans			
Discount rates – interest costs	**4.18%**	5.02%	4.27%
Discount rates – service costs	**4.49**	5.02	4.27
Expected long-term return on plan assets	**8.20**	8.20	8.20
Annual salary increase	**3.59**	3.59	3.59
Other postretirement benefit plans			
Discount rate – interest costs	**4.03%**	4.85%	4.04%
Discount rate – service costs	**4.39**	4.85	4.04
Expected long-term return on plan assets	**6.48**	6.75	6.74
Annual salary increase	**3.59**	3.59	3.59

Assumptions used to determine benefit obligations:	**2015**	2014
Pension plans		
Discount rate	**4.65%**	4.18%
Annual salary increase	**4.46**	3.59
Other postretirement benefit plans		
Discount rate	**4.49%**	4.03%
Annual salary increase	**4.46**	3.59

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, 2015 measurement date, the Company adopted new mortality tables for its pension and other postretirement benefit plans, which reflect decreased life expectancies in the U.S. The adoption of new mortality tables reduced the projected benefit obligations for the Company's pension plans and other postretirement benefit plans by approximately $66 million and $17 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, 2015 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate is Reached
Pre-65	6.50%	4.50%	2024
Post-65 medical	5.50	4.50	2024
Post-65 prescription	10.00	4.50	2025

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, 2015 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$ 58	$ (50)
Service and interest costs	2	(2)

Pension Plans

The total accumulated benefit obligation for the pension plans was $3.3 billion at December 31, 2015 and $3.5 billion at December 31, 2014. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2015 and 2014 were as follows:

	2015	2014
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 3,781**	$ 3,116
Service cost	**73**	62
Interest cost	**154**	153
Benefits paid	**(188)**	(149)
Actuarial loss (gain)	**(205)**	599
Balance at end of year	**3,615**	3,781
Change in plan assets		
Fair value of plan assets at beginning of year	**3,383**	3,085
Actual return (loss) on plan assets	**(13)**	285
Employer contributions	**14**	162
Benefits paid	**(188)**	(149)
Fair value of plan assets at end of year	**3,196**	3,383
Accrued liability	**$ (419)**	$ (398)

At December 31, 2015, the projected benefit obligations for the qualified and non-qualified pension plans were $3.5 billion and $151 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2015 and 2014 related to the Company's pension plans consist of the following:

	2015	2014
	(in millions)	
Other regulatory assets, deferred	**$ 1,076**	$ 1,102
Current liabilities, other	**(13)**	(12)
Employee benefit obligations	**(406)**	(386)

Presented below are the amounts included in regulatory assets at December 31, 2015 and 2014 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 2016.

	2015	2014	**Estimated Amortization in 2016**
		(in millions)	
Prior service cost	**$ 8**	$ 17	**$ 5**
Net (gain) loss	**1,068**	1,085	**55**
Regulatory assets	**$ 1,076**	$ 1,102	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2015 and 2014 are presented in the following table:

	2015	2014
	(in millions)	
Regulatory assets:		
Beginning balance	**$ 1,102**	$ 610
Net (gain) loss	**59**	543
Reclassification adjustments:		
Amortization of prior service costs	**(9)**	(10)
Amortization of net gain (loss)	**(76)**	(41)
Total reclassification adjustments	**(85)**	(51)
Total change	**(26)**	492
Ending balance	**$ 1,076**	$ 1,102

Components of net periodic pension cost were as follows:

	2015	2014	2013
		(in millions)	
Service cost	**$ 73**	$ 62	$ 69
Interest cost	**154**	153	138
Expected return on plan assets	**(251)**	(228)	(212)
Recognized net loss	**76**	41	74
Net amortization	**9**	10	10
Net periodic pension cost	**$ 61**	$ 38	$ 79

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, 2015, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2016	$ 168
2017	176
2018	183
2019	189
2020	197
2021 to 2025	1,085

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2015 and 2014 were as follows:

	2015	2014
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 864**	$ 723
Service cost	**7**	6
Interest cost	**34**	34
Benefits paid	**(45)**	(44)
Actuarial loss (gain)	**(22)**	142
Plan amendment	**12**	—
Retiree drug subsidy	**4**	3
Balance at end of year	**854**	864
Change in plan assets		
Fair value of plan assets at beginning of year	**395**	407
Actual return (loss) on plan assets	**(6)**	21
Employer contributions	**10**	8
Benefits paid	**(41)**	(41)
Fair value of plan assets at end of year	**358**	395
Accrued liability	**$ (496)**	$ (469)

Amounts recognized in the balance sheets at December 31, 2015 and 2014 related to the Company's other postretirement benefit plans consist of the following:

	2015	2014
	(in millions)	
Other regulatory assets, deferred	**$ 223**	$ 213
Employee benefit obligations	**(496)**	(469)

Presented below are the amounts included in regulatory assets at December 31, 2015 and 2014 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 2016.

	2015	2014	**Estimated Amortization in 2016**
		(in millions)	
Prior service cost	**$ 8**	$ (5)	**$ 1**
Net (gain) loss	**215**	218	**9**
Regulatory assets	**$ 223**	$ 213	

The changes in the balance of regulatory assets related to the other postretirement benefit plans for the plan years ended December 31, 2015 and 2014 are presented in the following table:

	2015	2014
	(in millions)	
Regulatory assets:		
Beginning balance	**$ 213**	$ 69
Net (gain) loss	**9**	146
Change in prior service costs	**12**	—
Reclassification adjustments:		
Amortization of net gain (loss)	**(11)**	(2)
Total change	**10**	144
Ending balance	**$ 223**	$ 213

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

	2015	2014	2013
		(in millions)	
Service cost	**$ 7**	$ 6	$ 7
Interest cost	**34**	34	31
Expected return on plan assets	**(24)**	(25)	(24)
Net amortization	**11**	2	12
Net periodic postretirement benefit cost	**$ 28**	$ 17	$ 26

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)	
2016	$ 53	$ (4)	$ 49
2017	55	(4)	51
2018	58	(5)	53
2019	59	(5)	54
2020	60	(5)	55
2021 to 2025	305	(28)	277

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, 2015 and 2014, along with the targeted mix of assets for each plan, is presented below:

	Target	**2015**	2014
Pension plan assets:			
Domestic equity	26%	**30%**	30%
International equity	25	**23**	23
Fixed income	23	**23**	27
Special situations	3	**2**	1
Real estate investments	14	**16**	14
Private equity	9	**6**	5
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	40%	**34%**	38%
International equity	21	**27**	26
Domestic fixed income	23	**25**	24
Global fixed income	9	**8**	7
Special situations	1	**—**	—
Real estate investments	4	**4**	4
Private equity	2	**2**	1
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, 2015 and 2014. 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, 2015 and 2014 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, 2015:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Net Asset Value as a Practical Expedient (NAV)**	**Total**
			(in millions)		
Assets:					
Domestic equity*	$ 565	$ 236	$ —	$ —	$ 801
International equity*	412	343	—	—	755
Fixed income:					
U.S. Treasury, government, and agency bonds	—	157	—	—	157
Mortgage- and asset-backed securities	—	69	—	—	69
Corporate bonds	—	394	—	—	394
Pooled funds	—	173	—	—	173
Cash equivalents and other	—	50	—	—	50
Real estate investments	103	—	—	421	524
Private equity	—	—	—	220	220
Total	$ 1,080	$ 1,422	$ —	$ 641	$ 3,143

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

	Fair Value Measurements Using				
As of December 31, 2014:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Net Asset Value as a Practical Expedient (NAV)	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.

The fair values of other postretirement benefit plan assets as of December 31, 2015 and 2014 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, 2015:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Net Asset Value as a Practical Expedient (NAV)**	**Total**
			(in millions)		
Assets:					
Domestic equity*	$ 30	$ 36	$ —	$ —	$ 66
International equity*	12	41	—	—	53
Fixed income:					
U.S. Treasury, government, and agency bonds	—	5	—	—	5
Mortgage- and asset-backed securities	—	2	—	—	2
Corporate bonds	—	12	—	—	12
Pooled funds	—	30	—	—	30
Cash equivalents and other	10	6	—	—	16
Trust-owned life insurance	—	158	—	—	158
Real estate investments	3	—	—	12	15
Private equity	—	—	—	7	7
Total	$ 55	$ 290	$ —	$ 19	$ 364

* 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, 2014:	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)	Net Asset Value as a Practical Expedient (NAV)	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.

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 2015, 2014, and 2013 were $26 million, $25 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

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 affected sites. 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 PRPs at the Brunswick site have completed a removal action as ordered by the EPA. Additional response actions at this site are anticipated. In September 2015, the Company entered into an allocation agreement with another PRP, under which that PRP will be responsible (as between the Company and that PRP) for paying and performing certain investigation, assessment, remediation, and other incidental activities at the Brunswick site. Assessment and potential cleanup of other sites are anticipated.

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.

In December 2014, the Court of Federal Claims entered a judgment in favor of the Company in its spent nuclear fuel lawsuit seeking damages for the period from January 1, 2005 through December 31, 2010. On March 19, 2015, the Company recovered approximately $18 million, based on its ownership interests. In March 2015, the Company credited the award to accounts where the original costs were charged and reduced rate base, fuel, and cost of service for the benefit of customers.

In March 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. The damage period was subsequently extended to December 31, 2014. 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, 2015 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.

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

FERC Matters

The Company has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional operating companies (including the Company) and Southern Power filed a triennial market power analysis in June 2014, which included continued reliance on the energy auction as tailored mitigation. On April 27, 2015, the FERC issued an order finding that the traditional operating companies' (including the Company's) and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional operating companies and in some adjacent areas. The FERC directed the traditional operating companies (including the Company) and Southern Power to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional operating companies (including the Company) and Southern Power filed a request for rehearing on May 27, 2015 and on June 26, 2015 filed their response with the FERC. The ultimate outcome of this matter cannot be determined at this time.

Retail Regulatory Matters

Rate Plans

In 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.

In January 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 an increase to tariffs effective January 1, 2015 as follows: (1) traditional base tariff rates by approximately $107 million; (2) ECCR tariff by approximately $23 million; (3) DSM tariffs by approximately $3 million; and (4) MFF tariff by approximately $3 million, for a total increase in base revenues of approximately $136 million.

On December 16, 2015, in accordance with the 2013 ARP, the Georgia PSC approved an increase to tariffs effective January 1, 2016 as follows: (1) traditional base tariff rates by approximately $49 million; (2) ECCR tariff by approximately $75 million; (3) DSM tariffs by approximately $3 million; and (4) MFF tariff by approximately $13 million, for a total increase in base revenues of approximately $140 million.

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. In 2014, the Company's retail ROE exceeded 12.00%, and the Company will refund to retail customers approximately $11 million in 2016, as approved by the Georgia PSC on February 18, 2016. In 2015, the Company's retail ROE was within the allowed retail ROE range.

The Company is required to file a general base 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 Plan

To comply with the April 16, 2015 effective date of the MATS rule, Plant Branch Units 1, 3, and 4 (1,266 MWs), Plant Yates Units 1 through 5 (579 MWs), and Plant McManus Units 1 and 2 (122 MWs) were retired and operations were discontinued at Plant Mitchell Unit 3 (155 MWs) by April 15, 2015, and Plant Kraft Units 1 through 4 (316 MWs) were retired on October 13, 2015. The switch to natural gas as the primary fuel was completed at Plant Yates Units 6 and 7 by June 2015 and at Plant Gaston Units 1 through 4 by December 2015.

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 ending December 2022 and the amortization of the 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.

On January 29, 2016, the Company filed its triennial IRP (2016 IRP). The filing included a request to decertify Plant Mitchell Units 3, 4A, and 4B (217 MWs) and Plant Kraft Unit 1 (17 MWs) upon approval of the 2016 IRP. The 2016 IRP also reflects that the Company exercised its contractual option to sell its 33% ownership interest in the Intercession City unit (143 MWs total capacity) to Duke Energy Florida, Inc. See Note 4 for additional information.

In the 2016 IRP, the Company requested reclassification of the remaining net book value of Plant Mitchell Unit 3, as of its retirement date, to a regulatory asset to be amortized over a period equal to the unit's remaining useful life. The Company also requested that the Georgia PSC approve the deferral of the cost associated with materials and supplies remaining at the unit retirement dates to a regulatory asset, to be amortized over a period deemed appropriate by the Georgia PSC.

The decertification and retirement of these units are not expected to have a material impact on the Company's financial statements; however, the ultimate outcome depends on the Georgia PSC's orders in the 2016 IRP and next general base rate case.

Additionally, the 2016 IRP included a Renewable Energy Development Initiative requesting to procure up to 525 MWs of renewable resources utilizing market-based prices established through a competitive bidding process to expand the Company’s existing renewable initiatives, including the Advanced Solar Initiative.

A decision from the Georgia PSC on the 2016 IRP is expected in the third quarter 2016. The ultimate outcome of these matters 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 approved by the Georgia PSC in 2015, allowing it to use an array of derivative instruments within a 48-month time horizon effective January 1, 2016. See Note 11 under "Energy-Related Derivatives" for additional information. On December 15, 2015, the Georgia PSC approved the Company's request to lower annual billings by approximately $350 million effective January 1, 2016.

The Company's over recovered fuel balance totaled approximately $116 million at December 31, 2015 and is included in current liabilities and other deferred liabilities. At December 31, 2014, the Company's under recovered fuel balance totaled approximately $199 million and was included in current assets and other deferred charges and assets.

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, doing business as Dalton Utilities (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) (Westinghouse and Stone & Webster, Inc., collectively, Contractor), pursuant to which the Contractor agreed to design, engineer, procure, construct, and test two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities at Plant Vogtle (Vogtle 3 and 4 Agreement).

Under the terms of the Vogtle 3 and 4 Agreement, the 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, 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%.

On December 31, 2015, Westinghouse acquired Stone & Webster, Inc. from CB&I (Acquisition). In connection with the Acquisition, Stone & Webster, Inc. changed its name to WECTEC Global Project Services Inc. (WECTEC). Certain obligations of Westinghouse and Stone & Webster, Inc. have been guaranteed by Toshiba Corporation, Westinghouse's parent company, and CB&I's The Shaw Group Inc., respectively. Subject to the consent of the DOE, in connection with the Acquisition and pursuant to the settlement agreement described below, the guarantee of The Shaw Group Inc. will be terminated. The guarantee of Toshiba Corporation remains in place. 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. Additionally, on January 13, 2016, as a result of recent credit rating downgrades of Toshiba Corporation, Westinghouse provided the Vogtle Owners with letters of credit in an aggregate amount of $900 million in accordance with, and subject to adjustment under, the terms of the Vogtle 3 and 4 Agreement.

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 may arise as construction proceeds.

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4. In addition, 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 an initial NCCR tariff of approximately $223 million effective January 1, 2011, as well as increases to the NCCR tariff of approximately $35 million, $50 million, $60 million, $27 million, and $19 million effective January 1, 2012, 2013, 2014, 2015, and 2016, respectively.

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 construction capital costs to be borne by the Company increase by 5% above the certified cost 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. In February 2013, the Company 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 (from April 2016) and the fourth quarter 2018 (from April 2017) for Plant Vogtle Units 3 and 4, respectively. In October 2013, the Georgia PSC approved a stipulation (2013 Stipulation) between the Company and the Georgia PSC Staff (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.

On April 15, 2015, the Georgia PSC issued a procedural order in connection with the twelfth VCM report, which included a requested amendment (Requested Amendment) to the Plant Vogtle Units 3 and 4 certificate to reflect the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4 (second quarter of 2019 and second quarter of 2020, respectively) as well as additional estimated Vogtle Owner's costs, of approximately $10 million per month, including property taxes, oversight costs, compliance costs, and other operational readiness costs to include the estimated Vogtle 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. Pursuant to the Georgia PSC's procedural order, the Georgia PSC deemed the Requested Amendment unnecessary and withdrawn until the completion of construction of Plant Vogtle Unit 3 consistent with the 2013 Stipulation. The Georgia PSC recognized that the certified cost and the 2013 Stipulation do not constitute a cost recovery cap. 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. Financing costs up to the certified amount will be collected through the NCCR tariff until the units are placed in service and contemplated in a general base rate case, while financing costs on any construction-related costs in excess of the $4.4 billion certified amount are expected to be recovered through AFUDC.

In 2012, the Vogtle Owners and the Contractor commenced litigation 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. The Contractor also asserted that it was entitled to extensions of the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. In May 2014, the Contractor filed an amended claim 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. In June 2015, the Contractor updated its estimated damages to an aggregate (based on the Company's ownership interest) of approximately $714 million (in 2015 dollars). The case was pending in the U.S. District Court for the Southern District of Georgia (Vogtle Construction Litigation).

On December 31, 2015, Westinghouse and the Vogtle Owners entered into a definitive settlement agreement (Contractor Settlement Agreement) to resolve disputes between the Vogtle Owners and the Contractor under the Vogtle 3 and 4 Agreement, including the Vogtle Construction Litigation. Effective December 31, 2015, the Company, acting for itself and as agent for the other Vogtle Owners, and the Contractor entered into an amendment to the Vogtle 3 and 4 Agreement to implement the Contractor Settlement Agreement. The Contractor Settlement Agreement and the related amendment to the Vogtle 3 and 4 Agreement (i) restrict the Contractor's ability to seek further increases in the contract price by clarifying and limiting the circumstances that constitute nuclear regulatory changes in law; (ii) provide for enhanced dispute resolution procedures; (iii) revise the guaranteed substantial completion dates to match the current estimated in-service dates of June 30, 2019 for Unit 3 and June 30, 2020 for Unit 4; (iv) provide that delay liquidated damages will now commence from the current estimated nuclear fuel loading date for each unit, which is December 31, 2018 for Unit 3 and December 31, 2019 for Unit 4, rather than the original guaranteed substantial completion dates under the Vogtle 3 and 4 Agreement; and (v) provide that the Company, based on its ownership interest, will pay to the Contractor and capitalize to the project cost approximately $350 million, of which approximately $120 million has been paid previously under the dispute resolution procedures of the Vogtle 3 and 4 Agreement. Further, subsequent to December 31, 2015, the Company paid approximately $121 million under the terms of the Contractor Settlement Agreement. In addition, the Contractor Settlement Agreement provides for the resolution of other open existing items relating to the scope of the project under the Vogtle 3 and 4 Agreement, including cyber security, for which costs were reflected in the Company's previously disclosed in-service cost estimate. Further, as part of the settlement and in connection with the Acquisition: (i) Westinghouse has engaged Fluor Enterprises, Inc., a subsidiary of Fluor Corporation, as a new construction subcontractor; and (ii) the Vogtle Owners, CB&I, and The Shaw Group Inc. have entered into mutual releases of any and all claims arising out of events or circumstances in connection with the construction of Plant Vogtle Units 3 and 4 that occurred on or before the date of the Contractor Settlement Agreement. On January 5, 2016, the Vogtle Construction Litigation was dismissed with prejudice.

On January 21, 2016, the Company submitted the Contractor Settlement Agreement and the related amendment to the Vogtle 3 and 4 Agreement to the Georgia PSC for its review. On February 2, 2016, the Georgia PSC ordered the Company to file supplemental information by April 5, 2016 in support of the Contractor Settlement Agreement and the Company's position that all construction costs to date have been prudently incurred and that the current estimated in-service capital cost and schedule are reasonable. Following the Company's filing under the order, the Staff will conduct a review of all costs incurred related to Plant Vogtle Units 3 and 4, the schedule for completion of Plant Vogtle Units 3 and 4, and the Contractor Settlement Agreement and the Staff is authorized to engage in related settlement discussions with the Company and any intervenors.

The order provides that the Staff is required to report to the Georgia PSC by October 5, 2016 with respect to the status of its review and any settlement-related negotiations. If a settlement with the Staff is reached with respect to costs of Plant Vogtle Units 3 and 4, the Georgia PSC will then conduct a hearing to consider whether to approve that settlement. If a settlement with the Staff is not reached, the Georgia PSC will determine how to proceed, including (i) modifying the 2013 Stipulation, (ii) directing the Company to file a request for an amendment to the certificate for Plant Vogtle Units 3 and 4, (iii) issuing a scheduling order to address remaining disputed issues, or (iv) taking any other option within its authority.

The Georgia PSC has approved thirteen VCM reports covering the periods through June 30, 2015, including construction capital costs incurred, which through that date totaled $3.1 billion. On February 26, 2016, the Company filed its fourteenth VCM report with the Georgia PSC covering the period from July 1 through December 31, 2015. The fourteenth VCM report does not include a requested amendment to the certified cost of Plant Vogtle Units 3 and 4. The Company is requesting approval of $160 million of construction capital costs incurred during that period. The Company anticipates to incur average financing costs of approximately $27 million per month from January 2016 until Plant Vogtle Units 3 and 4 are placed in service. The updated in-service capital cost forecast is $5.44 billion and includes costs related to the Contractor Settlement Agreement. Estimated financing costs during the construction period total approximately $2.4 billion. The Company's CWIP balance for Plant Vogtle Units 3 and 4 was approximately $3.6 billion as of December 31, 2015.

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 may 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 challenges with Contractor performance including 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.

Future claims by the Contractor or the Company (on behalf of the Vogtle Owners) could arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the Vogtle 3 and 4 Agreement and, under the enhanced dispute resolution procedures, may be resolved through litigation after the completion of nuclear fuel load for both units.

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

4. JOINT OWNERSHIP AGREEMENTS

The Company and Alabama Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 MWs, as well as associated transmission facilities. The capacity of these units is sold equally to the Company and Alabama Power under a power contract. The Company and Alabama Power make payments sufficient to provide for the operating expenses, taxes, interest expense, and a ROE. The Company's share of purchased power totaled $78 million in 2015, $84 million in 2014, and $91 million in 2013 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. Subsequent to December 31, 2015, the Company exercised its contractual option to sell its ownership interest to Duke Energy Florida, Inc. contingent on regulatory approvals. The ultimate outcome of this matter cannot be determined at this time; however, no material impact on the Company's financial statements is expected.

At December 31, 2015, 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%	$ 3,503	$ 2,084	$ 63
Plant Hatch (nuclear)	50.1	1,230	568	90
Plant Wansley (coal)	53.5	915	290	13
Plant Scherer (coal)				
Units 1 and 2	8.4	260	86	1
Unit 3	75.0	1,223	433	1
Rocky Mountain (pumped storage)	25.4	181	125	—
Intercession City (combustion-turbine)	33.3	13	4	—

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

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

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and various combined and separate state income tax returns. 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:

	2015	2014	2013
		(in millions)	
Federal –			
Current	**$ 515**	$ 295	$ 277
Deferred	**176**	366	374
	691	661	651
State –			
Current	**81**	82	(30)
Deferred	**(3)**	(14)	102
	78	68	72
Total	**$ 769**	$ 729	$ 723

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:

	2015	2014
	(in millions)	
Deferred tax liabilities –		
Accelerated depreciation	**$ 4,909**	$ 4,732
Property basis differences	**943**	811
Employee benefit obligations	**310**	329
Under-recovered fuel costs	**—**	81
Premium on reacquired debt	**61**	66
Regulatory assets associated with employee benefit obligations	**528**	534
Asset retirement obligations	**706**	497
Other	**187**	160
Total	**7,644**	7,210
Deferred tax assets –		
Federal effect of state deferred taxes	**150**	148
Employee benefit obligations	**642**	642
Other property basis differences	**88**	86
Other deferred costs	**83**	86
Cost of removal obligations	**6**	11
State investment tax credit carryforward	**188**	152
Federal tax credit carryforward	**3**	5
Over-recovered fuel costs	**45**	—
Unbilled fuel revenue	**47**	46
Asset retirement obligations	**706**	497
Other	**59**	63
Total	**2,017**	1,736
Accumulated deferred income taxes	**$ 5,627**	$ 5,474

On November 20, 2015, the FASB issued ASU 2015-17, which simplifies the presentation of deferred income taxes. The new guidance resulted in a reclassification from prepaid income taxes of $34 million to non-current accumulated deferred income taxes in the Company's December 31, 2014 balance sheet. See Note 1 under "Recently Issued Accounting Standards" for additional information.

The application of bonus depreciation provisions in current tax law has significantly increased deferred tax liabilities related to accelerated depreciation in 2015 and 2014.

At December 31, 2015, tax-related regulatory assets to be recovered from customers were $683 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, 2015, tax-related regulatory liabilities to be credited to customers were $105 million. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and unamortized ITCs.

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 2015, $10 million in 2014, and $5 million in 2013. State investment tax and other tax credits are recognized in the period in which the credits are claimed on the state income tax return and totaled $33 million in 2015, $34 million in 2014, and $27 million in 2013. At December 31, 2015, the Company had $3 million in federal tax credit carryforwards that will expire by 2035 and $188 million in state ITC carryforwards that will expire between 2020 and 2026.

Effective Tax Rate

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

	2015	2014	2013
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**2.5**	2.2	2.5
Non-deductible book depreciation	**1.2**	1.3	1.3
AFUDC equity	**(0.7)**	(0.8)	(0.6)
Other	**(0.4)**	(0.7)	(0.4)
Effective income tax rate	**37.6%**	37.0%	37.8%

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

Unrecognized Tax Benefits

Changes in unrecognized tax benefits were as follows:

	2015	2014	2013
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ —**	$ —	$ 23
Tax positions increase from prior periods	**3**	—	—
Tax positions decrease from prior periods	**—**	—	(23)
Balance at end of year	**$ 3**	$ —	**$ —**

The tax positions increase from prior periods for 2015 primarily relates to a graduated tax rate adjustment on the 2014 federal income tax return and will impact the Company's effective tax rate, if recognized. The tax positions decrease from prior periods for 2013 primarily relates to the Company's compliance with final U.S. Treasury regulations for a tax accounting method change for repairs.

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.

It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months. The settlement of federal and state audits could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013 and 2014 federal income tax returns and has received partial acceptance letters from the IRS; however, the IRS has not finalized its audits. 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 2011.

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:

	2015	2014
	(in millions)	
Senior notes	**$ 700**	$ 1,050
Pollution control revenue bonds	**4**	98
Capital lease	**8**	6
Unamortized debt issuance expense	**—**	(4)
Total	**$ 712**	$ 1,150

Maturities through 2020 applicable to total long-term debt are as follows: $712 million in 2016; $459 million in 2017; $761 million in 2018; $512 million in 2019; and $49 million in 2020.

Senior Notes

In December 2015, the Company issued $500 million aggregate principal amount of Series 2015A 1.95% Senior Notes due December 1, 2018. The proceeds were used to repay at maturity $250 million aggregate principal amount of the Company's Series Z 5.25% Senior Notes due December 15, 2015, to repay a portion of the Company's short-term indebtedness, and for general corporate purposes, including the Company's continuous construction program.

At December 31, 2015 and 2014, the Company had $6.3 billion and $6.9 billion of senior notes outstanding, respectively. These senior notes are effectively subordinated to all secured debt of the Company, which aggregated $2.4 billion and $1.2 billion at December 31, 2015 and 2014, respectively. As of December 31, 2015, the Company's secured debt included borrowings of $2.2 billion guaranteed by the DOE and capital lease obligations. As of December 31, 2014, the Company's secured debt was related to borrowings guaranteed by the DOE and 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, 2015 and 2014 was $1.8 billion and $1.6 billion, respectively.

In May 2015, the Company reoffered to the public $104.6 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 2013, which had been previously purchased and held by the Company since 2013.

In August 2015, in connection with optional tenders, the Company repurchased and reoffered to the public $94.6 million aggregate principal amount of Development Authority of Bartow County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Bowen Project), First Series 2009 and $10 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 2013.

In November 2015, the Company reoffered to the public $89.2 million aggregate principal amount of Development Authority of Monroe County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Scherer Project), Second Series 2009 and $46 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 1996, which had been previously repurchased and held by the Company since 2010.

Bank Term Loans

In March 2015, the Company entered into a $250 million aggregate principal amount three-month floating rate bank loan bearing interest based on one-month LIBOR. The proceeds were used for working capital and other general corporate purposes and the loan was repaid at maturity.

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) in February 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 are 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%.

In February 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 are being amortized over the life of the borrowings under the FFB Credit Facility.

In December 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.

In June and December 2015, the Company made additional borrowings under the FFB Credit Facility in an aggregate principal amount of $600 million and $400 million, respectively. The interest rate applicable to the $600 million principal amount is 3.283% and the interest rate applicable to the $400 million principal amount is 3.072%, both 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, 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, 2015 and 2014, the Company had a capital lease asset for its corporate headquarters building of $61 million, with accumulated depreciation at December 31, 2015 and 2014 of $26 million and $21 million, respectively. At December 31, 2015 and 2014, the capitalized lease obligation was $35 million and $40 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.

At December 31, 2015, the Company had capital lease assets and corresponding obligations of $149 million and $148 million, respectively, for two affiliate PPAs that became effective in 2015. Contractual lease payments, including imputed interest, of $20 million and capital lease asset amortization of $10 million were included in purchased power, affiliates expense in 2015. The annual imputed interest rates will range from 13% to 14% for these two capital lease PPAs over their term. For ratemaking purposes, the Georgia PSC has allowed the capital lease asset amortization in cost of service and the imputed interest in the Company's cost of debt. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

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, 2015, the Company had a $1.75 billion committed credit arrangement with banks, of which $1.73 billion was unused. These credit arrangements expire in 2020.

In August 2015, the Company amended and restated its multi-year credit arrangement, which, among other things, extended the maturity date from 2018 to 2020. The Company increased its borrowing ability by $150 million under its facility maturing in 2020 and terminated its aggregate $150 million facilities maturing in 2016.

Subject to applicable market conditions, the Company expects to renew this bank credit arrangement, as needed, prior to expiration. In connection therewith, the Company may extend the maturity date and/or increase or decrease the lending commitments thereunder. This bank credit arrangement requires 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 arrangement contains a covenant that limits the Company's debt levels to 65% of total capitalization, as defined in the agreement. For purposes of this definition, debt excludes certain hybrid securities.

A portion of the $1.73 billion unused credit with banks is allocated to provide liquidity support to the Company's 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, 2015 was $872 million. In addition, at December 31, 2015, the Company had $69 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

The Company makes short-term borrowings primarily through a commercial paper program that has the liquidity support of the Company's committed bank credit arrangements 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.

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, 2015:		
Commercial paper	**$ 158**	**0.6%**
December 31, 2014:		
Commercial paper	$ 156	0.3 %

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 2015, 2014, and 2013, the Company incurred fuel expense of $2.0 billion, $2.5 billion, and $2.3 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. On December 15, 2015, the Company's natural gas hedging program was revised and approved by the Georgia PSC.

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 Units 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 $10 million, $19 million, and $27 million in 2015, 2014, and 2013, 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 $203 million, $167 million, and $162 million for 2015, 2014, and 2013, respectively. Estimated total long-term obligations at December 31, 2015 were as follows:

	Affiliate Capital Leases	Affiliate Operating Leases	Non-Affiliate Operating Leases [4]	Vogtle Units 1 and 2 Capacity Payments	Total ($)
			(in millions)		
2016	$ 22	$ 99	$ 115	$ 10	$ 246
2017	22	71	123	8	224
2018	22	62	126	7	217
2019	23	63	127	8	221
2020	23	64	123	4	214
2021 and thereafter	227	538	1,007	47	1,819
Total	$ 339	$ 897	$ 1,621	$ 84	$ 2,941
Less: amounts representing executory costs[1]	54				
Net minimum lease payments	285				
Less: amounts representing interest[2]	84				
Present value of net minimum lease payments[3]	$ 201				

(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 commenced under the PPAs beginning in 2015, the Company recognized 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 $304 million 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 $29 million for 2015, $28 million for 2014, and $32 million for 2013. The Company includes any step rents, fixed escalations, and lease concessions in its computation of minimum lease payments.

As of December 31, 2015, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Railcars	Other	Total
		(in millions)	
2016	$ 15	$ 8	$ 23
2017	10	8	18
2018	5	7	12
2019	1	7	8
2020	1	6	7
2021 and thereafter	3	13	16
Total	$ 35	$ 49	$ 84

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 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-Based Compensation

Stock-based compensation, in the form of Southern Company stock options and performance share units, may be granted through the Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2015, there were 1,002 current and former employees participating in the stock option and performance share unit programs.

Stock Options

Through 2009, stock-based compensation granted to employees consisted exclusively of non-qualified stock options. The exercise price for stock options granted equaled the stock price of Southern Company common stock on the date of grant. Stock options vest on a pro rata basis over a maximum period of three years from the date of grant or immediately upon the retirement or death of the employee. Options expire no later than 10 years after the grant date. All unvested stock options vest immediately upon a change in control where Southern Company is not the surviving corporation. Compensation expense is generally recognized on a straight-line basis over the three-year vesting period with the exception of employees that are retirement eligible at the grant date and employees that will become retirement eligible during the vesting period. Compensation expense in those instances is recognized at the grant date for employees that are retirement eligible and through the date of retirement eligibility for those employees that become retirement eligible during the vesting period. In 2015, Southern Company discontinued the granting of stock options. As a result, stock-based compensation granted to employees in 2015 consisted exclusively of performance share units.

For the years ended December 31, 2014 and 2013, employees of the Company were granted stock options for 2,034,150 shares and 1,509,662 shares, respectively. The weighted average grant-date fair value of stock options granted during 2014 and 2013 derived using the Black-Scholes stock option pricing model was $2.20 and $2.93, 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, 2015, 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, 2015, 2014, and 2013 was $9 million, $19 million, and $16 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $4 million, $7 million, and $6 million for the years ended December 31, 2015, 2014, and 2013, respectively. As of December 31, 2015, the aggregate intrinsic value for the options outstanding and options exercisable was $45 million and $38 million, respectively.

Performance Share Units

From 2010 through 2014, stock-based compensation granted to employees included performance share units in addition to stock options. Beginning in 2015, stock-based compensation consisted exclusively of performance share units. Performance share units granted to employees vest at the end of a three-year performance period which equates to the requisite service period for accounting purposes. All unvested performance share units vest immediately upon a change in control where Southern Company is not the surviving corporation. Shares of Southern Company common stock are delivered to employees at the end of the performance period with the number of shares issued ranging from 0% to 200% of the target number of performance share units granted, based on achievement of the performance goals established by the Compensation Committee of the Southern Company Board of Directors.

The performance goal for all performance share units issued from 2010 through 2014 was based on the total shareholder return (TSR) for Southern Company common stock during the three-year performance period as compared to a group of industry peers. For these performance share units, at the end of three years, active employees receive shares based on Southern Company's performance while retired employees receive a pro rata number of shares based on the actual months of service during the performance period prior to retirement. The fair value of TSR-based performance share unit awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's common stock among the industry peers over the performance period. The Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement.

Beginning in 2015, Southern Company issued two additional types of performance share units to employees in addition to the TSR-based awards. These included performance share units with performance goals based on cumulative earnings per share (EPS) over the performance period and performance share units with performance goals based on Southern Company's equity-weighted ROE over the performance period. The EPS-based and ROE-based awards each represent 25% of total target grant date fair value of the performance share unit awards granted. The remaining 50% of the target grant date fair value consists of TSR-based awards. In contrast to the Monte Carlo simulation model used to determine the fair value of the TSR-based awards, the fair values of the EPS-based awards and the ROE-based awards are based on the closing stock price of Southern Company common stock on the date of the grant. Compensation expense for the EPS-based and ROE-based awards is generally recognized ratably over the three-year performance period initially assuming a 100% payout at the end of the performance period. The TSR-based performance share units, along with the EPS-based and ROE-based awards, issued in 2015, vest immediately upon the retirement of the employee. As a result, compensation expense for employees that are retirement eligible at the grant date is recognized immediately while compensation expense for employees that become retirement eligible during the vesting period is recognized over the period from grant date to the date of retirement eligibility. The expected payout related to the EPS-based and ROE-based awards is reevaluated annually with expense recognized to date increased or decreased based on the number of shares currently expected to be issued. Unlike the TSR-based awards, the compensation expense ultimately recognized for the EPS-based awards and the ROE-based awards will be based on the actual number of shares issued at the end of the performance period.

For the years ended December 31, 2015, 2014, and 2013, employees of the Company were granted performance share units of 236,804, 176,224, and 161,240, respectively. The weighted average grant-date fair value of TSR-based performance share units granted during 2015, 2014, and 2013, 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 $46.41, $37.54, and $40.50, respectively. The weighted average grant-date fair value of both EPS-based and ROE-based performance share units granted during 2015 was $47.78.

For the years ended December 31, 2015, 2014, and 2013, total compensation cost for performance share units recognized in income was $15 million, $6 million, and $6 million, respectively, with the related tax benefit also recognized in income of $6 million, $2 million, and $2 million, respectively. 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, 2015, there was $4 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 19 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 $13.5 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. In April 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 $84 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, 2015, assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

	Fair Value Measurements Using			
As of December 31, 2015:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Energy-related derivatives	$ —	$ 2	$ —	$ 2
Interest rate derivatives	—	5	—	5
Nuclear decommissioning trusts:(*)				
Domestic equity	182	1	—	183
Foreign equity	—	113	—	113
U.S. Treasury and government agency securities	—	125	—	125
Municipal bonds	—	64	—	64
Corporate bonds	—	143	—	143
Mortgage and asset backed securities	—	127	—	127
Other	16	4	—	20
Cash equivalents	63	—	—	63
Total	$ 261	$ 584	$ —	$ 845
Liabilities:				
Energy-related derivatives	$ —	$ 15	$ —	$ 15
Interest rate derivatives	—	6	—	6
Total	$ —	$ 21	$ —	$ 21

(*) 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, 2014, assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, 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:(*)				
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

(*) 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 products that are valued using observable market data and assumptions commonly used by market participants. The fair value of interest rate derivatives reflect the net present value of expected payments and receipts under the swap agreement based on the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and occasionally, implied volatility of interest rate options. The interest rate derivatives are categorized as Level 2 under Fair Value Measurements as these inputs are based on observable data and valuations of similar instruments. See Note 11 for additional information on how these derivatives are used.

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. 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' judgments, are also obtained when available. See Note 1 under "Nuclear Decommissioning" for additional information.

The Company early adopted ASU 2015-07 effective December 31, 2015 on a retrospective basis. The guidance removed certain disclosures required for all investments that are eligible to be measured at fair value using the net asset value per share practical expedient regardless of whether the practical expedient was used. As of December 31, 2015 and 2014, the Company had no investments measured at net asset value as a practical expedient.

As of December 31, 2015 and 2014, 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, including securities due within one year:		
2015	**$ 10,145**	**$ 10,480**
2014	$ 9,673	$ 10,552

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 available 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.

Energy-related derivative contracts are accounted for under 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, 2015, the net volume of energy-related derivative contracts for natural gas positions totaled 50 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, 2015, 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, 2015
	(in millions)				*(in millions)*
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	2
	500	1.95%	3-month LIBOR + .76%	December 2018	(3)
Total	$ 1,400				$ —

The estimated pre-tax gains (losses) that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2016 are $4 million. 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, 2015 and 2014, 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**	**2015**	2014	**Balance Sheet Location**	**2015**	2014
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ 2**	$ 6	Liabilities from risk management activities	**$ 12**	$ 23
	Other deferred charges and assets	**—**	1	Other deferred credits and liabilities	**3**	4
Total derivatives designated as hedging instruments for regulatory purposes		**$ 2**	$ 7		**$ 15**	$ 27
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Interest rate derivatives:	Other current assets	**$ 5**	$ 5	Liabilities from risk management activities	**$ —**	$ 9
	Other deferred charges and assets	**—**	1	Other deferred credits and liabilities	**6**	5
Total derivatives designated as hedging instruments in cash flow and fair value hedges		**$ 5**	$ 6		**$ 6**	$ 14
Total		**$ 7**	$ 13		**$ 21**	$ 41

Energy-related derivatives not designated as hedging instruments were immaterial on the balance sheets for 2015 and 2014.

The Company's derivative contracts 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, 2015 and 2014 are presented in the following tables.

Fair Value					
Assets	**2015**	2014	**Liabilities**	**2015**	2014
	(in millions)			*(in millions)*	
Energy-related derivatives presented in the Balance Sheet [(a)]	**$ 2**	$ 7	Energy-related derivatives presented in the Balance Sheet [(a)]	**$ 15**	$ 27
Gross amounts not offset in the Balance Sheet [(b)]	**(2)**	(7)	Gross amounts not offset in the Balance Sheet [(b)]	**(2)**	(7)
Net energy-related derivative assets	**$ —**	$ —	**Net energy-related derivative liabilities**	**$ 13**	$ 20
Interest rate derivatives presented in the Balance Sheet [(a)]	**$ 5**	$ 6	Interest rate derivatives presented in the Balance Sheet [(a)]	**$ 6**	$ 14
Gross amounts not offset in the Balance Sheet [(b)]	**(4)**	(6)	Gross amounts not offset in the Balance Sheet [(b)]	**(4)**	(6)
Net interest rate derivative assets	**$ 1**	$ —	**Net interest rate derivative liabilities**	**$ 2**	$ 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, 2015 and 2014, the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred were as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2015**	2014	**Balance Sheet Location**	**2015**	2014
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$ (12)**	$ (23)	Other regulatory liabilities, current	**$ 2**	$ 6
	Other regulatory assets, deferred	**(3)**	(4)	Other deferred credits and liabilities	**—**	1
Total energy-related derivative gains (losses)		**$ (15)**	$ (27)		**$ 2**	$ 7

For the years ended December 31, 2015, 2014, and 2013, the pre-tax effects of interest rate derivatives designated as cash flow hedging instruments on the statements of income were as follows:

Derivatives in Cash Flow Hedging Relationships	**Gain (Loss) Recognized in OCI on Derivative (Effective Portion)**			**Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)**			
						Amount	
Derivative Category	**2015**	2014	2013	**Statements of Income Location**	**2015**	2014	2013
		(in millions)				*(in millions)*	
Interest rate derivatives	**$ (15)**	$ (8)	$ —	Interest expense, net of amounts capitalized	**$ (3)**	$ (3)	$ (3)

For the years ended December 31, 2015 and 2014, the pre-tax effects of interest rate derivatives designated as fair value hedging instruments on the statements of income were 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 statements of income were offset by changes to the carrying value of long-term debt. The gains and losses related to interest rate derivative settlements of fair value hedges are recorded directly to earnings.

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, 2015, the Company's collateral posted with its derivative counterparties was immaterial.

At December 31, 2015, the fair value of derivative liabilities with contingent features was $1 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 $52 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 2015 and 2014 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
		(in millions)	
March 2015	**$ 1,978**	**$ 454**	**$ 236**
June 2015	**2,016**	**554**	**277**
September 2015	**2,691**	**964**	**551**
December 2015	**1,641**	**376**	**196**
March 2014	$ 2,269	$ 516	$ 266
June 2014	2,186	572	311
September 2014	2,631	920	525
December 2014	1,902	288	123

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

[This page intentionally left blank]

SELECTED FINANCIAL AND OPERATING DATA 2011-2015
Georgia Power Company 2015 Annual Report

	2015	2014	2013	2012	2011
Operating Revenues (in millions)	**$ 8,326**	$ 8,988	$ 8,274	$ 7,998	$ 8,800
Net Income After Dividends on Preferred and Preference Stock (in millions)	**$ 1,260**	$ 1,225	$ 1,174	$ 1,168	$ 1,145
Cash Dividends on Common Stock (in millions)	**$ 1,034**	$ 954	$ 907	$ 983	$ 1,096
Return on Average Common Equity (percent)	**11.92**	12.24	12.45	12.76	12.89
Total Assets (in millions)[(a)(b)]	**$ 32,865**	$ 30,872	$ 28,776	$ 28,618	$ 27,045
Gross Property Additions (in millions)	**$ 2,332**	$ 2,146	$ 1,906	$ 1,838	$ 1,981
Capitalization (in millions):					
Common stock equity	**$ 10,719**	$ 10,421	$ 9,591	$ 9,273	$ 9,023
Preferred and preference stock	**266**	266	266	266	266
Long-term debt[(a)]	**9,616**	8,563	8,571	7,928	7,944
Total (excluding amounts due within one year)	**$ 20,601**	$ 19,250	$ 18,428	$ 17,467	$ 17,233
Capitalization Ratios (percent):					
Common stock equity	**52.0**	54.1	52.0	53.1	52.4
Preferred and preference stock	**1.3**	1.4	1.4	1.5	1.5
Long-term debt[(a)]	**46.7**	44.5	46.6	45.4	46.1
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**2,127,658**	2,102,673	2,080,358	2,062,040	2,047,390
Commercial[(c)]	**304,179**	301,246	298,420	296,397	295,288
Industrial[(c)]	**9,141**	9,132	9,136	9,143	9,134
Other	**9,261**	9,003	8,623	7,724	7,521
Total	**2,450,239**	2,422,054	2,396,537	2,375,304	2,359,333
Employees (year-end)	**7,989**	7,909	7,886	8,094	8,310

(a) A reclassification of debt issuance costs from Total Assets to Long-term debt of $124 million, $62 million, $67 million, and $75 million is reflected for years 2014, 2013, 2012, and 2011, respectively, in accordance with ASU 2015-03. See Note 1 under "Recently Issued Accounting Standards" for additional information.

(b) A reclassification of deferred tax assets from Total Assets of $34 million, $68 million, $117 million, and $31 million is reflected for years 2014, 2013, 2012, and 2011, respectively, in accordance with ASU 2015-17. See Note 1 under "Recently Issued Accounting Standards" for additional information.

(c) A reclassification of customers from commercial to industrial is reflected for years 2011-2013 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.

	2015	2014	2013	2012	2011
Operating Revenues (in millions):					
Residential	**$ 3,240**	$ 3,350	$ 3,058	$ 2,986	$ 3,241
Commercial	**3,094**	3,271	3,077	2,965	3,217
Industrial	**1,305**	1,525	1,391	1,322	1,547
Other	**88**	94	94	89	94
Total retail	**7,727**	8,240	7,620	7,362	8,099
Wholesale — non-affiliates	**215**	335	281	281	341
Wholesale — affiliates	**20**	42	20	20	32
Total revenues from sales of electricity	**7,962**	8,617	7,921	7,663	8,472
Other revenues	**364**	371	353	335	328
Total	**$ 8,326**	$ 8,988	$ 8,274	$ 7,998	$ 8,800
Kilowatt-Hour Sales (in millions):					
Residential	**26,649**	27,132	25,479	25,742	27,223
Commercial	**32,719**	32,426	31,984	32,270	32,900
Industrial	**23,805**	23,549	23,087	23,089	23,519
Other	**632**	633	630	641	657
Total retail	**83,805**	83,740	81,180	81,742	84,299
Wholesale — non-affiliates	**3,501**	4,323	3,029	2,934	3,904
Wholesale — affiliates	**552**	1,117	496	600	626
Total	**87,858**	89,180	84,705	85,276	88,829
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**12.16**	12.35	12.00	11.60	11.91
Commercial	**9.46**	10.09	9.62	9.19	9.78
Industrial	**5.48**	6.48	6.03	5.73	6.58
Total retail	**9.22**	9.84	9.39	9.01	9.61
Wholesale	**5.80**	6.93	8.54	8.52	8.23
Total sales	**9.06**	9.66	9.35	8.99	9.54
Residential Average Annual Kilowatt-Hour Use Per Customer	**12,582**	12,969	12,293	12,509	13,288
Residential Average Annual Revenue Per Customer	**$ 1,529**	$ 1,605	$ 1,475	$ 1,451	$ 1,582
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**15,455**	17,593	17,586	17,984	16,588
Maximum Peak-Hour Demand (megawatts):					
Winter	**15,735**	16,308	12,767	14,104	14,800
Summer	**16,104**	15,777	15,228	16,440	16,941
Annual Load Factor (percent)	**61.9**	61.2	63.5	59.1	59.5
Plant Availability (percent)*:					
Fossil-steam	**85.6**	86.3	87.1	90.3	88.6
Nuclear	**94.1**	90.8	91.8	94.1	92.2
Source of Energy Supply (percent):					
Coal	**24.5**	30.9	26.4	26.6	44.4
Nuclear	**17.6**	16.7	17.7	18.3	16.6
Hydro	**1.6**	1.3	2.0	0.7	1.1
Oil and gas	**28.3**	26.3	29.6	22.0	8.9
Purchased power —					
From non-affiliates	**5.0**	3.8	3.3	6.8	6.1
From affiliates	**23.0**	21.0	21.0	25.6	22.9
Total	**100.0**	100.0	100.0	100.0	100.0

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

DIRECTORS AND OFFICERS
Georgia Power Company 2015 Annual Report

Directors

W. Paul Bowers
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

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

Kessel D. Stelling, Jr. (Elected effective 1/1/2016)
Chairman and Chief Executive Officer
Synovus Financial Corporation.

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

Charles K. Tarbutton
Treasurer and Director
B-H Transfer Co.

Beverly Daniel Tatum
President Emerita
Spelman College

D. Gary Thompson (Retiring effective 5/18/2016)
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
Chairman, President, and Chief Executive Officer
Georgia Power Company

W. Craig Barrs
Executive Vice President
Customer Service and Operations

Christopher P. Cummiskey (Elected effective 5/9/2015)
Executive Vice President
External Affairs

W. Ron Hinson (Elected Corporate Secretary effective 1/1/2016)
Executive Vice President, Chief Financial Officer, Treasurer, and Corporate Secretary

Joseph A. (Buzz) Miller (Resigned effective 2/14/2016)
Executive Vice President
Nuclear Development

Anthony L. Wilson (Resigned effective 5/1/2015)
Executive Vice President
Customer Service and Operations

Michael K. Anderson
Senior Vice President
Community and Corporate Relations

Thomas P. Bishop (Resigned effective 1/1/2016)
Senior Vice President, General Counsel, Corporate Secretary, and Chief Compliance Officer

Pedro P. Cherry
Senior Vice President
Metro Atlanta Region

Kenneth E. Coleman
Senior Vice President
Marketing

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

DIRECTORS AND OFFICERS
Georgia Power Company 2015 Annual Report

Latanza W. Adjei
Vice President
Sales

Mark S. Berry (Elected effective 8/19/2015)
Vice President
Environmental Affairs

Daryl E. Brown (Resigned effective 8/4/2015)
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
West Region

Kristi L. Dow (Elected effective 3/1/2016)
Assistant Secretary

J. Truitt Eavenson
Vice President
Governmental and Regulatory Affairs

Sloane N. Evans (Elected effective 5/1/2015)
Vice President
Human Resources

Nicole A. Faulk (Resigned effective 5/1/2015)
Vice President
West Region

Fran G. Forehand
Vice President
East Region

Jeff G. Franklin (Elected effective 5/1/2015)
Vice President
Supply Chain

Glen R. Grizzle
Vice President
East Region

Cathy P. Hill
Vice President
Coastal Region

Valerie Hendrickson (Elected effective 5/20/2015)
Vice President
Corporate Communications

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 (Retired effective 5/20/2015)
Assistant Treasurer

Jason E. Manley
Vice President
South Region

William N. (Norrie) McKenzie
Vice President
Renewable Development

David L. McKinney
Vice President
Nuclear Development

Christie D. Miree (Resigned effective 8/29/2015)
Vice President
Information Technology

Leonard Owens (Retired effective 5/1/2015)
Vice President
Human Resources and Labor

Todd A. Perkins (Elected effective 5/20/2015)
Assistant Treasurer

David P. Poroch
Vice President and Comptroller

D. Emi Rahn (Resigned effective 3/1/2016)
Assistant Secretary

Gregory N. Roberts
Vice President
Pricing and Planning

Louise L. Scott
Vice President
Customer Services

Ronald Shipman
Vice President
Central Region

Leslie R. Sibert
Vice President
Distribution

Michael J. Sullivan (Elected effective 3/28/2016)
Vice President
Information Technology

H. Murry Weaver II
Vice President
Northwest Region

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 2.45 million customers within its service area. In 2015, retail energy sales accounted for 95% of the Company's total sales of 87.9 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
Wells Fargo Bank, National Association
101 North Phillips Avenue
One Wachovia Center
Sioux Falls, SD 57104

Registrar, Transfer Agent, and Dividend Paying Agent
For Preferred Stock and Preference Stock
Effective April 6, 2016
Wells Fargo Shareowner Services
P.O. Box 64856
St. Paul, MN 55154-0856
(800) 554-7626

www.shareowneronline.com

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	2015	2014
	(in thousands)	
First	$258,570	$238,400
Second	258,570	238,400
Third	258,570	238,400
Fourth	258,570	238,400

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

[This page intentionally left blank]

[This page intentionally left blank]

[This page intentionally left blank]