ALABAMA POWER COMPANY

2015 ANNUAL REPORT

ALABAMA POWER

A SOUTHERN COMPANY

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

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

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

Mark A. Crosswhite
Chairman, President, and Chief Executive Officer

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

February 26, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Alabama Power Company

We have audited the accompanying balance sheets and statements of capitalization of Alabama Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 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 29 to 73) present fairly, in all material respects, the financial position of Alabama 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

Birmingham, Alabama
February 26, 2016

DEFINITIONS

Term	Meaning
AFUDC	Allowance for funds used during construction
ASC	Accounting Standards Codification
CCR	Coal combustion residuals
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
DOE	U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GAAP	U.S. generally accepted accounting principles
Georgia Power	Georgia Power Company
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
NDR	Natural Disaster Reserve
NRC	U.S. Nuclear Regulatory Commission
OCI	Other comprehensive income
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
Rate CNP	Rate Certificated New Plant
Rate CNP Compliance	Rate Certificated New Plant Compliance
Rate CNP Environmental	Rate Certificated New Plant Environmental
Rate CNP PPA	Rate Certificated New Plant Power Purchase Agreement
Rate ECR	Rate Energy Cost Recovery
Rate NDR	Rate Natural Disaster Reserve
Rate RSE	Rate Stabilization and Equalization plan
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

DEFINITIONS
(continued)

Term	Meaning
traditional operating companies..	Alabama Power Company, Georgia Power, Gulf Power, and Mississippi Power

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Alabama Power Company 2015 Annual Report

OVERVIEW

Business Activities

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

Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, reliability, fuel, capital expenditures, and restoration following major storms. 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.

Key Performance Indicators

The Company continues to focus on several key performance indicators including customer satisfaction, plant availability, system reliability, and net income after dividends on preferred and preference stock. The Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys 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 fossil/hydro 2015 Peak Season EFOR of 1.89% was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance. The Company's performance for 2015 was below the target for transmission reliability measures primarily due to the level of storm activity in the service territory during the year and was better than target for distribution reliability measures.

The Company uses net income after dividends on preferred and preference stock as the primary measure of the Company's financial performance. 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 $785 million, representing a $24 million, or 3.2%, increase over the previous year. The increase was due primarily to an increase in rates under Rate RSE effective January 1, 2015. This increase was partially offset by a decrease in weather-related revenues resulting from milder weather experienced in 2015 as compared to 2014 and an increase in amortization.

The Company's 2014 net income after dividends on preferred and preference stock was $761 million, representing a $49 million, or 6.9%, increase over the previous year. The increase was due primarily to an increase in weather-related revenues 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, an increase in revenues related to net investments under Rate CNP Environmental, and an increase in AFUDC resulting from increased capital expenditures. The factors increasing net income were partially offset by an increase in total operating 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	**$ 5,768**	**$ (174)**	$ 324
Fuel	**1,342**	**(263)**	(26)
Purchased power	**351**	**(34)**	156
Other operations and maintenance	**1,501**	**33**	179
Depreciation and amortization	**643**	**40**	(42)
Taxes other than income taxes	**368**	**12**	8
Total operating expenses	**4,205**	**(212)**	275
Operating income	**1,563**	**38**	49
Allowance for equity funds used during construction	**60**	**11**	17
Interest income	**15**	**—**	(1)
Interest expense, net of amounts capitalized	**274**	**19**	(4)
Other income (expense), net	**(47)**	**(25)**	14
Income taxes	**506**	**(6)**	34
Net income	**811**	**11**	49
Dividends on preferred and preference stock	**26**	**(13)**	—
Net income after dividends on preferred and preference stock	**$ 785**	**$ 24**	$ 49

Operating Revenues

Operating revenues for 2015 were $5.8 billion, reflecting a $174 million decrease from 2014. Details of operating revenues were as follows:

	Amount	
	2015	2014
	(in millions)	
Retail — prior year	**$ 5,249**	$ 4,952
Estimated change resulting from —		
Rates and pricing	**204**	81
Sales growth (decline)	**(11)**	7
Weather	**(43)**	85
Fuel and other cost recovery	**(165)**	124
Retail — current year	**5,234**	5,249
Wholesale revenues —		
Non-affiliates	**241**	281
Affiliates	**84**	189
Total wholesale revenues	**325**	470
Other operating revenues	**209**	223
Total operating revenues	**$ 5,768**	$ 5,942
Percent change	**(2.9)%**	5.8%

Retail revenues in 2015 were $5.2 billion. These revenues decreased $15 million, or 0.3%, in 2015 and increased $297 million, or 6.0%, in 2014, each as compared to the prior year. The decrease in 2015 was due to decreased fuel revenues and milder weather in

2015 as compared to 2014, partially offset by increased revenues due to a Rate RSE increase effective January 1, 2015. The increase in 2014 was due to increased fuel revenues, 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 increased revenues related to net investments under Rate CNP Environmental primarily resulting from the inclusion of pre-2005 environmental assets. See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information. See "Energy Sales" herein for a discussion of changes in the volume of energy sold, including changes related to sales growth and weather.

Fuel rates billed to customers are designed to fully recover fluctuating fuel and purchased power costs over a period of time. Fuel revenues generally have no effect on net income because they represent the recording of revenues to offset fuel and purchased power expenses. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate ECR" for additional information.

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

	2015	2014	2013
		(in millions)	
Capacity and other	**$ 140**	$ 154	$ 143
Energy	**101**	127	105
Total non-affiliated	**$ 241**	$ 281	$ 248

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 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 energy sales are also included in wholesale energy sales to non-affiliates. These opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost to produce the energy.

In 2015, wholesale revenues from sales to non-affiliates decreased $40 million, or 14.2%, as compared to the prior year. This decrease reflects a $26 million decrease in revenues from energy sales and a $14 million decrease in capacity revenues. In 2015, KWH sales decreased 6.3% primarily due to the market availability of lower cost natural gas resources and an 8.4% decrease in the price of energy due to lower natural gas prices. In 2014, wholesale revenues from sales to non-affiliates increased $33 million, or 13.3%, as compared to the prior year primarily due to the availability of the Company's lower cost generation. This increase reflects a $22 million increase in revenues from energy sales and an $11 million increase in capacity revenues. In 2014, KWH sales increased 12.3% primarily due to the availability of the Company's lower cost generation and a 1.1% increase in the price of energy primarily due to higher natural gas prices.

Wholesale revenues from sales to affiliated companies will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the FERC. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost and energy purchases are generally offset by energy revenues through the Company's energy cost recovery clause.

In 2015, wholesale revenues from sales to affiliates decreased $105 million, or 55.6%, as compared to the prior year. In 2015, KWH sales decreased 33.9% as a result of lower cost generation in the Southern Company system and a 32.8% decrease in the price of energy primarily due to lower natural gas prices. In 2014, wholesale revenues from sales to affiliates decreased $23 million, or 10.8%, as compared to the prior year primarily related to a decrease in revenue from energy sales. In 2014, KWH sales decreased 21.7% primarily due to decreased hydro generation as the result of less rainfall as well as the addition of new generation in the Southern Company system, partially offset by a 13.7% increase in the price of energy primarily due to higher natural gas prices.

In 2015, other operating revenues decreased $14 million, or 6.3%, as compared to the prior year primarily due to decreases in co-generation steam revenues due to lower natural gas prices and transmission revenues related to the open access transmission tariff, partially offset by an increase in transmission service agreement revenues. In 2014, other operating revenues increased $17 million, or 8.3%, as compared to the prior year primarily due to increases in open access transmission tariff revenues, transmission service agreement revenues, and co-generation steam 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	**18.1**	**(3.4)%**	4.5%	**0.1 %**	(0.8)%
Commercial	**14.1**	**(0.1)**	1.6	**0.1**	(1.3)
Industrial	**23.4**	**(1.8)**	3.9	**(1.8)**	3.9
Other	**0.2**	**(4.9)**	—	**(4.9)**	—
Total retail	**55.8**	**(1.9)**	3.5	**(0.7)%**	1.0 %
Wholesale —					
Non-affiliates	**4.3**	**(6.3)**	12.3		
Affiliates	**3.8**	**(33.8)**	(21.7)		
Total wholesale	**8.1**	**(21.5)**	(9.4)		
Total energy sales	**63.9**	**(4.9)%**	1.3%		

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. Retail energy sales in 2015 were 1.9% lower than in 2014. Residential and commercial sales decreased 3.4% and 0.1%, respectively, due primarily to milder weather in 2015 as compared to 2014. Weather-adjusted residential and commercial sales were flat in 2015. Industrial sales decreased 1.8% in 2015 compared to 2014 as a result of a decrease in demand resulting from changes in production levels primarily in the primary metals sector. A strong dollar, low oil prices, and weak global growth conditions have constrained growth in the industrial sector in 2015.

Retail energy sales in 2014 were 3.5% higher than in 2013. Residential and commercial sales increased 4.5% and 1.6%, respectively, due primarily 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. Weather-adjusted residential and commercial sales decreased 0.8% and 1.3%, respectively, due primarily to a decrease in customer demand in 2014 compared to 2013. Industrial sales increased 3.9% in 2014 compared to 2013 as a result of an increase in demand resulting from changes in production levels primarily in the primary metals, chemicals, automotive and plastics, and stone, clay, and glass sectors. 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 revenues from sales to non-affiliates and wholesale revenues from sales to affiliated companies as related to changes in price and KWH sales.

Fuel and Purchased Power Expenses

Fuel costs constitute one of the largest expenses for the Company. The mix of fuel sources for generation of electricity is determined primarily by the unit cost of fuel consumed, demand, 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)*	**60.9**	63.6	65.3
Total purchased power *(billions of KWHs)*	**6.3**	6.6	4.0
Sources of generation *(percent)* —			
Coal	**54**	54	53
Nuclear	**24**	23	21
Gas	**16**	17	17
Hydro	**6**	6	9
Cost of fuel, generated *(cents per net KWH)* —			
Coal	**2.83**	3.14	3.29
Nuclear	**0.81**	0.84	0.84
Gas	**2.94**	3.69	3.38
Average cost of fuel, generated *(cents per net KWH)*[(a)]	**2.34**	2.68	2.73
Average cost of purchased power *(cents per net KWH)*[(b)]	**5.66**	5.92	5.76

(a) KWHs generated by hydro are excluded from the average cost of fuel, generated.

(b) Average cost of purchased power includes fuel, energy, and transmission purchased by the Company for tolling agreements where power is generated by the provider.

Fuel and purchased power expenses were $1.7 billion in 2015, a decrease of $297 million, or 14.9%, compared to 2014. The decrease was primarily due to a $184 million decrease in the average cost of fuel, a $79 million decrease in the volume of KWHs generated, an $18 million decrease related to the volume of KWHs purchased, and a $16 million decrease in the average cost of purchased power.

Fuel and purchased power expenses were $2.0 billion in 2014, an increase of $130 million, or 7.0%, compared to 2013. The increase was primarily due to a $147 million increase related to the volume of KWHs purchased and a $10 million increase in the average cost of purchased power. These increases were partially offset by a $19 million decrease in the average cost of fuel and an $8 million decrease in the volume of KWHs generated.

Fuel and purchased power energy transactions do not have a significant impact on earnings, since energy expenses are generally offset by energy revenues through the Company's energy cost recovery clause. The Company, along with the Alabama PSC, continuously monitors the under/over recovered balance to determine whether adjustments to billing rates are required. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate ECR" for additional information.

Fuel

Fuel expenses were $1.3 billion in 2015, a decrease of $263 million, or 16.4%, compared to 2014. The decrease was primarily due to a 20.4% decrease in the average cost of KWHs generated by natural gas, which excludes tolling agreements, a 9.9% decrease in the average cost of KWHs generated by coal, an 8.5% decrease in the volume of KWHs generated by natural gas, and a 4.0% decrease in the volume of KWHs generated by coal. Fuel expenses were $1.6 billion in 2014, a decrease of $26 million, or 1.6%, compared to 2013. The decrease was primarily due to a 4.5% decrease in the average cost of KWHs generated by coal, partially offset by a 30.8% decrease in the volume of KWHs generated by hydro facilities as a result of less rainfall, and a 9.2% increase in the average cost of KWHs generated by natural gas, which excludes tolling agreements.

Purchased Power – Non-Affiliates

In 2015, purchased power expense from non-affiliates was $171 million, a decrease of $14 million, or 7.6%, compared to 2014. The decrease was primarily due to a 19.5% decrease in the average cost per KWH purchased primarily due to lower gas prices partially offset by a 15.2% increase in the amount of energy purchased due to the market availability of lower cost generation. In 2014, purchased power expense from non-affiliates was $185 million, an increase of $85 million, or 85.0%, compared to 2013. The increase was primarily due to a 42.1% increase in the average cost per KWH purchased primarily due to demand during peak periods and a 28.8% increase in the amount of energy purchased to meet the demand created during cold weather in the first quarter 2014 and the addition of a new PPA in 2014.

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 $180 million in 2015, a decrease of $20 million, or 10.0%, compared to 2014. This decrease was primarily due to a 16.9% decrease in the amount of energy purchased due to milder weather in 2015 as compared to 2014, partially offset by an 8.3% increase in the average cost per KWH purchased related to steam support at Plant Gaston. Purchased power expense from affiliates was $200 million in 2014, an increase of $71 million, or 55.0%, compared to 2013. This increase was primarily due to a 96.4% increase in the amount of energy purchased to meet the demand created during cold weather in the first quarter 2014, partially offset by a 20.8% decrease in the average cost per KWH purchased due to the availability of lower cost Southern Company system generation at the time of purchase.

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

Other Operations and Maintenance Expenses

In 2015, other operations and maintenance expenses increased $33 million, or 2.2%, as compared to the prior year. Administrative and general expenses increased $53 million primarily due to increased employee benefit costs including pension costs. Nuclear production expenses increased $19 million primarily due to outage amortization costs. These increases were partially offset by a decrease in steam production costs of $21 million primarily due to timing of outages. Distribution expenses decreased $12 million primarily due to overhead line maintenance expenses.

In 2014, other operations and maintenance expenses increased $179 million, or 13.9%, as compared to the prior year. Steam production, other power generation, and hydro generation expenses increased $110 million primarily due to scheduled outage costs. See Note 3 to the financial statements under "Retail Regulatory Matters – Cost of Removal Accounting Order" for additional information. Distribution and transmission expenses increased $31 million primarily related to increases in maintenance and labor expenses. Nuclear production expenses increased $14 million primarily related to labor expenses.

Depreciation and Amortization

Depreciation and amortization increased $40 million, or 6.6%, in 2015 as compared to the prior year. The increase in 2015 was primarily due to the amortization of $120 million of the regulatory liability for other cost of removal obligations in 2014, partially offset by decreases due to lower depreciation rates as a result of the depreciation study implemented in January 2015. Depreciation and amortization decreased $42 million, or 6.5%, in 2014 as compared to the prior year. The decrease in 2014 was primarily due to the amortization of $120 million of the regulatory liability for other cost of removal obligations, partially offset by increases due to depreciation rates related to environmental assets and amortization of certain regulatory assets. See Note 3 to the financial statements under "Retail Regulatory Matters – Cost of Removal Accounting Order" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $12 million, or 3.4%, in 2015 as compared to the prior year. The increase was primarily due to increases in state and municipal utility license tax bases primarily due to an increase in retail revenues. In addition, there were increases in ad valorem taxes primarily due to an increase in assessed value of property.

Allowance for Equity Funds Used During Construction

AFUDC equity increased $11 million, or 22.4%, in 2015 and $17 million, or 53.1% in 2014 as compared to the prior year primarily due to an increase in construction projects related to environmental and steam generation. See Note 1 to financial statements under "Allowance for Funds Used During Construction" for additional information.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized increased $19 million, or 7.5%, in 2015 as compared to the prior year. The increase in 2015 was primarily due to timing of debt issuances and redemptions partially offset by a decrease in interest rates. See FUTURE EARNINGS POTENTIAL – "Financing Activities" herein for additional information.

Other Income (Expense), Net

Other income (expense), net decreased $25 million, or 113.6%, in 2015 as compared to the prior year. The decrease in 2015 was primarily due to an increase in donations and a decrease in sales of non-utility property. Other income (expense), net increased $14 million, or 38.9%, in 2014 as compared to the prior year primarily due to a decrease in non-operating expenses and an increase in sales of non-utility property.

Income Taxes

Income taxes increased $34 million, or 7.1%, in 2014 as compared to the prior year primarily due to higher pre-tax earnings.

Dividends on Preferred and Preference Stock

Dividends on preferred and preference stock decreased $13 million, or 33.3%, in 2015 as compared to the prior year. The decrease in 2015 was primarily due to the redemption in May 2015 of certain series of preferred and preference stock. See Note 6 to the financial statements under "Redeemable Preferred Stock" for additional information.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate RSE" for additional information.

FUTURE EARNINGS POTENTIAL

General

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

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's primary business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining 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. Environmental compliance costs are recovered through Rate CNP Compliance. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate CNP" for additional information. 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 $3.9 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $349 million, $355 million, and $184 million for 2015, 2014, and 2013, respectively. The Company expects that capital expenditures to comply with environmental statutes and regulations will total approximately $851 million from 2016 through 2018, with annual totals of approximately $319 million, $263 million, and $269 million 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 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 – Environmental Accounting Order" herein for additional information on planned unit retirements and fuel conversions at the Company.

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. All areas within the Company's service territory have achieved attainment of the 2008 standard. 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.

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.

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

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 Alabama, 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. 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 Alabama) to revise or remove the provisions of their SIPs relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM) 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 existing or 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, the Alabama opacity rule, 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.

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 storage units consisting of landfills and surface impoundments (CCR Units) at six generating plants. In addition to on-site storage, the Company also sells a portion of its CCR to third parties for beneficial reuse. Individual states regulate CCR and the State of Alabama 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 and groundwater monitoring primarily related to ash ponds pursuant to the CCR Rule, the Company recorded 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 Alabama 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. Costs associated with the CCR Rule are expected to be recovered through Rate CNP Compliance. 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.

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 21^{st} 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 40 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2015 greenhouse gas emissions on the same basis is approximately 38 million metric tons of CO_2 equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation, the mix of fuel sources, and other factors.

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 Alabama PSC. The Company currently recovers its costs from the regulated retail business primarily through Rate RSE, Rate CNP, Rate ECR, and Rate NDR. In addition, the Alabama PSC issues accounting orders to address current events impacting the Company. See Note 1 to the financial statements and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information regarding the Company's rate mechanisms and accounting orders.

Rate RSE

The Alabama PSC has adopted Rate RSE that provides for periodic annual adjustments based upon the Company's projected weighted cost of equity (WCE) compared to an allowable range. Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate RSE adjustments for any two-year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0%. If the Company's actual retail return is above the allowed WCE range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail return fall below the WCE range.

On November 30, 2015, the Company made its annual Rate RSE submission to the Alabama PSC of projected data for 2016. Projected earnings were within the specified WCE range; therefore, retail rates under Rate RSE remained unchanged for 2016.

Rate CNP

The Company's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service under Rate CNP. The Company may also recover retail costs associated with certificated PPAs under Rate CNP PPA. On March 3, 2015, the Alabama PSC issued a consent order that the Company leave in effect the current Rate CNP PPA factor for billings for the period April 1, 2015 through March 31, 2016. No adjustment to Rate CNP PPA is expected in 2016.

Rate CNP Environmental allowed for the recovery of the Company's retail costs associated with environmental laws, regulations, and other such mandates. On March 3, 2015, the Alabama PSC approved a modification to Rate CNP Environmental to include compliance costs for both environmental and non-environmental mandates. The recoverable non-environmental compliance costs result from laws, regulations, and other mandates directed at the utility industry involving the security, reliability, safety, sustainability, or similar considerations impacting the Company's facilities or operations. This modification to Rate CNP Environmental was effective March 20, 2015 with the revised rate now defined as Rate CNP Compliance. The Company was limited to recover $50 million of non-environmental compliance costs for the year 2015. Additional non-environmental compliance costs were recovered through Rate RSE. Customer rates were not impacted by this order in 2015; therefore, the modification increased the under recovered position for Rate CNP Compliance during 2015. Rate CNP Compliance is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Compliance costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital.

On November 30, 2015, the Company made its annual Rate CNP Compliance submission to the Alabama PSC of its cost of complying with governmental mandates for cost year 2016. Rate CNP Compliance increased 4.5%, or approximately $250 million annually, effective January 1, 2016.

Rate ECR

The Company has established energy cost recovery rates under the Company's Rate ECR as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. The Company, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on the Company's net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per KWH.

On December 1, 2015, the Alabama PSC approved a decrease in the Company’s Rate ECR factor from 2.681 to 2.030 cents per KWH, 6.7%, or $370 million annually, based upon projected billings, effective January 1, 2016. The approved decrease in the Rate ECR factor will have no significant effect on the Company's net income, but will decrease operating cash flows related to fuel cost recovery in 2016 when compared to 2015. The rate will return to 2.681 cents per KWH in 2017 and 5.910 cents per KWH in 2018, absent a further order from the Alabama PSC.

Environmental Accounting Order

Based on an order from the Alabama PSC, the Company is allowed to establish a regulatory asset to record the unrecovered investment costs, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure associated with future unit retirements caused by environmental regulations. These costs are being amortized and recovered over the affected unit's remaining useful life, as established prior to the decision regarding early retirement through

Rate CNP Compliance. See "Environmental Matters – Environmental Statutes and Regulations" herein for additional information regarding environmental regulations.

In April 2015, as part of its environmental compliance strategy, the Company retired Plant Gorgas Units 6 and 7 (200 MWs). Additionally, in April 2015, the Company ceased using coal at Plant Barry Units 1 and 2 (250 MWs), but such units will remain available on a limited basis with natural gas as the fuel source. In accordance with the joint stipulation entered in connection with a civil enforcement action by the EPA, the Company retired Plant Barry Unit 3 (225 MWs) in August 2015 and it is no longer available for generation. The Company expects to cease using coal at Plant Greene County Units 1 and 2 (300 MWs) and begin operating those units solely on natural gas by April 2016.

In accordance with this accounting order from the Alabama PSC, the Company transferred the unrecovered plant asset balances to a regulatory asset at their respective retirement dates. The regulatory asset will be amortized and recovered through Rate CNP Compliance over the remaining useful lives, as established prior to the decision for retirement. As a result, these decisions will not have a significant impact on the Company's financial statements.

Renewables

On September 16, 2015, the Alabama PSC approved the Company's petition for a Renewable Generation Certificate for up to 500 MWs. This will allow the Company to build its own renewable projects, each less than 80 MWs, or purchase power from other renewable-generated sources.

Cost of Removal Accounting Order

In accordance with an accounting order issued in November 2014 by the Alabama PSC, in December 2014, the Company fully amortized the balance of $123 million in certain regulatory asset accounts and offset this amortization expense with the amortization of $120 million of the regulatory liability for other cost of removal obligations. The regulatory asset accounts fully amortized and terminated as of December 31, 2014 represented costs previously deferred under a compliance and pension cost accounting order as well as a non-nuclear outage accounting order, which were approved by the Alabama PSC in 2012 and 2013, respectively. Approximately $95 million of non-nuclear outage costs and $28 million of compliance and pension costs previously deferred were fully amortized in December 2014.

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 $240 million for the 2016 tax year.

Other Matters

In accordance with accounting standards related to employers' accounting for pensions, the Company recorded pension costs of $48 million in 2015, $23 million in 2014 and $47 million in 2013. Postretirement benefit costs for the Company were $5 million, $4 million, and $7 million in 2015, 2014, and 2013, respectively. Such amounts are dependent on several factors including trust earnings and changes to the plans. A portion of pension and postretirement benefit costs is capitalized based on construction-related labor charges. Pension and postretirement benefit costs are a component of the regulated rates and generally do not have a long-term effect on net income. For more information regarding pension and postretirement benefits, see Note 2 to the financial statements.

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has 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 Alabama PSC and wholesale regulation by the FERC. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation, 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 facility, Plant Farley, 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, asbestos removal, disposal of polychlorinated biphenyls in certain transformers, and disposal of sulfur hexafluoride gas in certain substation breakers. The Company also has identified retirement obligations related to certain transmission and distribution facilities and certain wireless communication towers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets 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.

As a result of the final CCR Rule discussed above, the Company recorded new AROs for facilities that are subject to the CCR Rule. 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. 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 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 $24 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 $7 million or less change in total annual benefit expense and a $98 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 in long-term debt totaling $39 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 Note 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 expenses of $20 million and accrued income tax of $2 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 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 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, preferred and preference stock issuances, or parent company capital contributions. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan and the nuclear decommissioning trust funds 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's funding obligations for the nuclear decommissioning trust fund are based on the site study, and the next study is expected to be conducted in 2018. See 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 $2.1 billion for 2015, an increase of $433 million as compared to 2014. The increase in cash provided from operating activities was primarily due to the timing of income tax payments and refunds associated with bonus depreciation, collection of fuel cost recovery revenues, partially offset by the timing of payment of accounts payable. Net cash provided from operating activities totaled $1.7 billion for 2014, a decrease of $205 million as compared to 2013. The decrease in cash provided from operating activities was primarily due to an increase in income tax payments and the timing of fossil fuel stock purchases, partially offset by the timing of payment of accounts payable.

Net cash used for investing activities totaled $1.5 billion for 2015, $1.6 billion for 2014, and $1.1 billion for 2013. In 2015, these activities were primarily related to gross property additions for environmental, distribution, steam generation, and transmission assets. In 2014, these activities were primarily related to gross property additions for environmental, distribution, transmission, steam generation, and nuclear fuel assets. In 2013, these activities were primarily related to gross property additions for steam generation, distribution, and transmission assets.

Net cash used for financing activities totaled $733 million in 2015 primarily due to the payment of common stock dividends and redemptions of securities, partially offset by issuances of long-term debt. Net cash used for financing activities totaled $164 million in 2014 primarily due to the payment of common stock dividends and issuances and redemptions of securities.

Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes for 2015 included an increase of $1.3 billion in property, plant, and equipment primarily due to additions to steam generation, environmental, distribution, and transmission facilities including $619 million in AROs associated with the CCR Rule. Other significant changes include an increase of $384 million in accumulated deferred income taxes primarily as a result of bonus depreciation and an increase of $263 million in long term debt, including debt due within one year, primarily due to the issuance of additional senior notes. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" and "Nuclear Decommissioning" and Note 5 to the financial statements under "Current and Deferred Income Taxes" for additional information.

The Company's ratio of common equity to total capitalization, including short-term debt, was 45.6% and 44.2% at December 31, 2015 and 2014, respectively. See Note 6 to the financial statements for additional information.

Sources of Capital

The Company plans to obtain the funds to meet its future capital needs through operating cash flows, short-term debt, term loans, external security issuances, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, depend upon prevailing market conditions, regulatory approval, and other factors.

Security issuances are subject to regulatory approval by the Alabama PSC. Additionally, with respect to the public offering of securities, the Company files registration statements with the SEC under the Securities Act of 1933, as amended. The amounts of securities authorized by the Alabama PSC are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

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

The Company's current liabilities sometimes exceed current assets because of the Company's debt due within one year and the periodic use of short-term debt as a funding source primarily to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the business.

At December 31, 2015, the Company had approximately $194 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2015 were as follows:

Expires					Due Within One Year	
2016	**2018**	**2020**	**Total**	**Unused**	**Term Out**	**No Term Out**
	(in millions)			*(in millions)*		*(in millions)*
$ 40	$ 500	$ 800	$ 1,340	$ 1,340	$ —	$ 40

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

Most of these bank credit arrangements contain covenants that limit debt levels and contain cross acceleration provisions to other indebtedness (including guarantee obligations) of the Company. Such cross acceleration provisions 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 all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings.

Subject to applicable market conditions, the Company expects to renew or replace its bank credit arrangements, as needed, prior to expiration. In connection therewith, the Company may extend the maturity dates 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 borrowings. As of December 31, 2015, the Company had $810 million of outstanding variable rate pollution control revenue bonds requiring liquidity support. In addition, at December 31, 2015, the Company had $80 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

In addition, the Company has substantial cash flow from operating activities and access to the capital markets, including a commercial paper program, to meet liquidity needs. The Company may meet short-term cash needs through its commercial paper program. The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each company under these arrangements are several and there is no cross-affiliate credit support.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period (*)		
	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	**$ —**	**—%**	**$ 14**	**0.2%**	**$ 100**
December 31, 2014:					
Commercial paper	$ —	—%	$ 13	0.2%	$ 300
December 31, 2013:					
Commercial paper	$ —	—%	$ 11	0.2%	$ 90

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

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

Financing Activities

In March 2015, the Company issued $550 million aggregate principal amount of Series 2015A 3.750% Senior Notes due March 1, 2045. The proceeds were used to redeem $250 million aggregate principal amount of Series DD 5.65% Senior Notes due March 15, 2035 and for general corporate purposes, including the Company's continuous construction program.

In April 2015, the Company purchased and held $80 million aggregate principal amount of Industrial Development Board of the City of Mobile, Alabama Pollution Control Revenue Bonds (Alabama Power Company Barry Plant Project), Series 2007-B. The Company reoffered these bonds to the public in May 2015.

Also in April 2015, the Company issued $175 million additional aggregate principal amount of its Series 2015A 3.750% Senior Notes due March 1, 2045 (Additional Series 2015A Senior Notes) and $250 million aggregate principal amount of its Series 2015B 2.800% Senior Notes due April 1, 2025 (Series 2015B Senior Notes). A portion of the proceeds of the Additional Series 2015A Senior Notes and the Series 2015B Senior Notes were used in May 2015 to redeem 6.48 million shares ($162 million aggregate stated capital) of the Company's 5.20% Class A Preferred Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date, 4.0 million shares ($100 million aggregate stated capital) of the Company's 5.30% Class A Preferred Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date, and 6.0 million shares ($150 million aggregate stated capital) of the Company's 5.625% Series Preference Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date, and the remaining net proceeds were used for general corporate purposes, including the Company's continuous construction program.

In June 2015, $18.7 million aggregate principal amount of the Industrial Development Board of the City of Mobile, Alabama Pollution Control Revenue Refunding Bonds (Alabama Power Company Project), Series 1994, $6.15 million aggregate principal amount of the Industrial Development Board of the City of Gadsden, Pollution Control Revenue Bonds (Alabama Power Company Project), Series 1994, and $28.85 million aggregate principal amount of the Industrial Development Board of the Town of Parrish, Pollution Control Revenue Refunding Bonds (Alabama Power Company Project), Series 1994A were repaid at maturity.

In October 2015, the Company repaid at maturity $400 million aggregate principal amount of its Series 2012B 0.550% Senior Notes due October 15, 2015.

Subsequent to December 31, 2015, the Company issued $400 million aggregate principal amount of Series 2016A 4.30% Senior Notes due January 2, 2046. The proceeds were used to repay at maturity $200 million aggregate principal amount of the

Company's Series FF 5.20% Senior Notes due January 15, 2016 and for general purposes, including the Company's continuous construction program.

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

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB and/or Baa2 or below. These contracts are primarily for physical electricity purchases, fuel purchases, fuel transportation and storage, energy price risk management, and transmission. 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 Baa2	$ 1
At BBB- and/or Baa3	$ 2
Below BBB- and/or Baa3	$ 350

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 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 financial hedge contracts for natural gas purchases. The Company continues to manage a retail fuel-hedging program implemented per the guidelines of the Alabama PSC. The Company had no material change in market risk exposure for the year ended December 31, 2015 when compared to the year ended December 31, 2014.

In addition, Rate ECR allows the recovery of specific costs associated with the sales of natural gas that become necessary due to operating considerations at the Company's electric generating facilities. Rate ECR also allows recovery of the cost of financial instruments used for hedging market price risk up to 75% of the budgeted annual amount of natural gas purchases. The Company may not engage in natural gas hedging activities that extend beyond a rolling 42-month window. Also, the premiums paid for natural gas financial options may not exceed 5% of the Company's natural gas budget for that year.

The changes in fair value of energy-related derivative contracts 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	**$ (52)**	$ (1)
Contracts realized or settled	**41**	(7)
Current period changes(*)	**(43)**	(44)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (54)**	$ (52)

(*) 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	**44**	54
Commodity – Natural gas options	**6**	2
Total hedge volume	**50**	56

The weighted average swap contract cost above market prices was approximately $1.13 per mmBtu as of December 31, 2015 and $0.89 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. The majority of the natural gas hedge gains and losses are recovered through the Company's retail energy cost recovery clause.

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. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the energy cost recovery clause. Certain other gains and losses on energy-related derivatives, designated as cash flow hedges, are initially deferred in OCI before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 10 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 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	(54)	(39)	(15)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$ (54)	$ (39)	$ (15)

The Company is exposed to market price risk in the event of nonperformance by counterparties to energy-related and interest rate derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's 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 $1.3 billion per year for 2016, 2017, and 2018. The construction program includes 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 per year for 2016, 2017, and 2018. 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 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 $20 million, $20 million, and $66 million 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. Costs associated with the CCR Rule are expected to be recovered through Rate CNP Compliance.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in the expected environmental compliance program; changes in FERC rules and regulations; Alabama PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

As a result of NRC requirements, the Company has external trust funds for nuclear decommissioning costs; however, the Company currently has no additional funding requirements. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning."

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 Alabama 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, pension and other postretirement benefit plans, preferred and preference stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 6, 7, and 11 to the financial statements for additional information.

Contractual Obligations

	2016	2017-2018	2019-2020	After 2020	Total
			(in millions)		
Long-term debt[(a)] —					
Principal	$ 200	$ 561	$ 450	$ 5,692	$ 6,903
Interest	275	500	461	3,706	4,942
Preferred and preference stock dividends[(b)]	17	34	34	—	85
Financial derivative obligations[(c)]	54	16	—	—	70
Operating leases[(d)]	19	22	18	13	72
Capital Lease	—	1	1	3	5
Purchase commitments —					
Capital[(e)]	1,210	2,370	—	—	3,580
Fuel[(f)]	1,108	1,638	886	261	3,893
Purchased power[(g)]	78	167	182	803	1,230
Other[(h)]	40	83	67	335	525
Pension and other postretirement benefit plans[(i)]	20	38	—	—	58
Total	$ 3,021	$ 5,430	$ 2,099	$ 10,813	$ 21,363

(a) All amounts are reflected based on final maturity dates. 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.

(b) Preferred and preference stock do not mature; therefore, amounts are provided 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 are 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 long-term commitments for the purchase of capacity and energy. Amounts are related to the Company's certificated PPAs which include MWs purchased from gas-fired and wind-powered facilities.

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

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

Cautionary Statement Regarding Forward-Looking Statements

The Company's 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 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, to construct facilities in accordance with the requirements of permits and licenses, and to satisfy any environmental performance standards;
- investment performance of the Company's employee and retiree benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- the inherent risks involved in operating nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, and financial risks;
- the ability to successfully operate generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
- 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;
- 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, tornadoes, 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.

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

	2015	2014	2013
		(in millions)	
Operating Revenues:			
Retail revenues	**$ 5,234**	$ 5,249	$ 4,952
Wholesale revenues, non-affiliates	**241**	281	248
Wholesale revenues, affiliates	**84**	189	212
Other revenues	**209**	223	206
Total operating revenues	**5,768**	5,942	5,618
Operating Expenses:			
Fuel	**1,342**	1,605	1,631
Purchased power, non-affiliates	**171**	185	100
Purchased power, affiliates	**180**	200	129
Other operations and maintenance	**1,501**	1,468	1,289
Depreciation and amortization	**643**	603	645
Taxes other than income taxes	**368**	356	348
Total operating expenses	**4,205**	4,417	4,142
Operating Income	**1,563**	1,525	1,476
Other Income and (Expense):			
Allowance for equity funds used during construction	**60**	49	32
Interest income	**15**	15	16
Interest expense, net of amounts capitalized	**(274)**	(255)	(259)
Other income (expense), net	**(47)**	(22)	(36)
Total other income and (expense)	**(246)**	(213)	(247)
Earnings Before Income Taxes	**1,317**	1,312	1,229
Income taxes	**506**	512	478
Net Income	**811**	800	751
Dividends on Preferred and Preference Stock	**26**	39	39
Net Income After Dividends on Preferred and Preference Stock	**$ 785**	$ 761	$ 712

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
Alabama Power Company 2015 Annual Report

		2015		2014		2013
				(in millions)		
Net Income	**$**	**811**	$	800	$	751
Other comprehensive income (loss):						
Qualifying hedges:						
Changes in fair value, net of tax of $(3), $(3), and $-, respectively		**(5)**		(5)		—
Reclassification adjustment for amounts included in net income, net of tax of $1, $1, and $1, respectively		**2**		2		1
Total other comprehensive income (loss)		**(3)**		(3)		1
Comprehensive Income	**$**	**808**	$	797	$	752

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
Alabama Power Company 2015 Annual Report

	2015	2014	2013
		(in millions)	
Operating Activities:			
Net income	**$ 811**	$ 800	$ 751
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	**780**	724	816
Deferred income taxes	**388**	270	198
Allowance for equity funds used during construction	**(60)**	(49)	(32)
Pension, postretirement, and other employee benefits	**20**	(61)	9
Stock based compensation expense	**15**	11	10
Other, net	**(20)**	17	(38)
Changes in certain current assets and liabilities —			
-Receivables	**(160)**	(58)	2
-Fossil fuel stock	**28**	61	146
-Materials and supplies	**15**	(17)	19
-Other current assets	**(3)**	(11)	5
-Accounts payable	**3**	157	35
-Accrued taxes	**138**	(199)	(23)
-Accrued compensation	**(16)**	50	(23)
-Retail fuel cost over recovery	**191**	5	42
-Other current liabilities	**12**	9	(3)
Net cash provided from operating activities	**2,142**	1,709	1,914
Investing Activities:			
Property additions	**(1,367)**	(1,457)	(1,107)
Nuclear decommissioning trust fund purchases	**(439)**	(245)	(280)
Nuclear decommissioning trust fund sales	**438**	244	279
Cost of removal net of salvage	**(71)**	(77)	(47)
Change in construction payables	**(15)**	(10)	(13)
Other investing activities	**(34)**	(22)	26
Net cash used for investing activities	**(1,488)**	(1,567)	(1,142)
Financing Activities:			
Proceeds —			
Capital contributions from parent company	**22**	28	24
Pollution control revenue bonds	**80**	254	—
Senior notes issuances	**975**	400	300
Redemptions and repurchases —			
Preferred and preference stock	**(412)**	—	—
Pollution control revenue bonds	**(134)**	(254)	—
Senior notes	**(650)**	—	(250)
Payment of preferred and preference stock dividends	**(31)**	(39)	(39)
Payment of common stock dividends	**(571)**	(550)	(644)
Other financing activities	**(12)**	(3)	(5)
Net cash used for financing activities	**(733)**	(164)	(614)
Net Change in Cash and Cash Equivalents	**(79)**	(22)	158
Cash and Cash Equivalents at Beginning of Year	**273**	295	137
Cash and Cash Equivalents at End of Year	**$ 194**	$ 273	$ 295
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $22, $18, and $11 capitalized, respectively)	**$ 250**	$ 231	$ 243
Income taxes (net of refunds)	**121**	436	296
Noncash transactions — accrued property additions at year-end	**121**	8	18

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

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

Assets	**2015**	2014
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 194**	$ 273
Receivables —		
Customer accounts receivable	**332**	345
Unbilled revenues	**119**	138
Under recovered regulatory clause revenues	**43**	74
Other accounts and notes receivable	**20**	23
Affiliated companies	**50**	37
Accumulated provision for uncollectible accounts	**(10)**	(9)
Income taxes receivable, current	**142**	—
Fossil fuel stock, at average cost	**239**	268
Materials and supplies, at average cost	**398**	406
Vacation pay	**66**	65
Prepaid expenses	**83**	224
Other regulatory assets, current	**115**	84
Other current assets	**10**	6
Total current assets	**1,801**	1,934
Property, Plant, and Equipment:		
In service	**24,750**	23,080
Less accumulated provision for depreciation	**8,736**	8,522
Plant in service, net of depreciation	**16,014**	14,558
Nuclear fuel, at amortized cost	**363**	348
Construction work in progress	**801**	1,006
Total property, plant, and equipment	**17,178**	15,912
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**71**	66
Nuclear decommissioning trusts, at fair value	**737**	756
Miscellaneous property and investments	**96**	84
Total other property and investments	**904**	906
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**522**	525
Deferred under recovered regulatory clause revenues	**99**	31
Other regulatory assets, deferred	**1,114**	1,063
Other deferred charges and assets	**103**	122
Total deferred charges and other assets	**1,838**	1,741
Total Assets	**$ 21,721**	$ 20,493

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

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

Liabilities and Stockholder's Equity	**2015**	2014
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 200**	$ 454
Accounts payable —		
Affiliated	**278**	248
Other	**410**	443
Customer deposits	**88**	87
Accrued taxes	**38**	37
Accrued interest	**73**	66
Accrued vacation pay	**55**	54
Accrued compensation	**119**	131
Liabilities from risk management activities	**55**	40
Other regulatory liabilities, current	**240**	2
Other current liabilities	**39**	40
Total current liabilities	**1,595**	1,602
Long-Term Debt (See accompanying statements)	**6,654**	6,137
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**4,241**	3,857
Deferred credits related to income taxes	**70**	72
Accumulated deferred investment tax credits	**118**	125
Employee benefit obligations	**388**	326
Asset retirement obligations	**1,448**	829
Other cost of removal obligations	**722**	744
Other regulatory liabilities, deferred	**136**	239
Deferred over recovered regulatory clause revenues	**—**	47
Other deferred credits and liabilities	**76**	78
Total deferred credits and other liabilities	**7,199**	6,317
Total Liabilities	**15,448**	14,056
Redeemable Preferred Stock (See accompanying statements)	**85**	342
Preference Stock (See accompanying statements)	**196**	343
Common Stockholder's Equity (See accompanying statements)	**5,992**	5,752
Total Liabilities and Stockholder's Equity	**$ 21,721**	$ 20,493
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
Alabama Power Company 2015 Annual Report

	2015	2014	**2015**	2014
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term debt payable to affiliated trusts —				
Variable rate (3.43% at 1/1/16) due 2042	**$ 206**	$ 206		
Long-term notes payable —				
0.55% due 2015	**—**	400		
5.20% due 2016	**200**	200		
5.50% to 5.55% due 2017	**525**	525		
5.125% due 2019	**200**	200		
3.375% due 2020	**250**	250		
2.80% to 6.125% due 2021-2045	**4,425**	3,700		
Total long-term notes payable	**5,600**	5,275		
Other long-term debt —				
Pollution control revenue bonds —				
0.28% to 5.00% due 2034	**287**	367		
Variable rate (0.03% at 1/1/15) due 2015	**—**	54		
Variable rates (0.05% to 0.06% at 1/1/16) due 2017	**36**	36		
Variable rates (0.01% to 0.09% at 1/1/16) due 2021-2038	**774**	694		
Total other long-term debt	**1,097**	1,151		
Capitalized lease obligations	**5**	5		
Unamortized debt premium (discount), net	**(9)**	(7)		
Unamortized debt issuance expense	**(45)**	(39)		
Total long-term debt (annual interest requirement — $275 million)	**6,854**	6,591		
Less amount due within one year	**200**	454		
Long-term debt excluding amount due within one year	**6,654**	6,137	**51.4%**	48.8%
Redeemable Preferred Stock:				
Cumulative redeemable preferred stock				
$100 par or stated value — 4.20% to 4.92%				
Authorized — 3,850,000 shares				
Outstanding — 475,115 shares	**48**	48		
$1 par value —				
Authorized — 27,500,000 shares				
Outstanding — $25 stated value				
— 2015: 5.83% — 1,520,000 shares				
— 2014: 5.20% to 5.83% — 12,000,000 shares				
(annual dividend requirement — $4 million)	**37**	294		
Total redeemable preferred stock	**85**	342	**0.7**	2.7
Preference Stock:				
Authorized — 40,000,000 shares				
Outstanding — $1 par value — $25 stated value				
— 2015: 6.45% to 6.50% — 8,000,000 shares (non-cumulative)				
— 2014: 5.63% to 6.50% — 14,000,000 shares (non-cumulative)				
(annual dividend requirement — $13 million)	**196**	343	**1.5**	2.7
Common Stockholder's Equity:				
Common stock, par value $40 per share —				
Authorized — 40,000,000 shares				
Outstanding — 30,537,500 shares	**1,222**	1,222		
Paid-in capital	**2,341**	2,304		
Retained earnings	**2,461**	2,255		
Accumulated other comprehensive loss	**(32)**	(29)		
Total common stockholder's equity	**5,992**	5,752	**46.4**	45.8
Total Capitalization	**$ 12,927**	$ 12,574	**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
Alabama 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	31	$ 1,222	$ 2,227	$ 1,976	$ (27)	$ 5,398
Net income after dividends on preferred and preference stock	—	—	—	712	—	712
Capital contributions from parent company	—	—	35	—	—	35
Other comprehensive income (loss)	—	—	—	—	1	1
Cash dividends on common stock	—	—	—	(644)	—	(644)
Balance at December 31, 2013	31	1,222	2,262	2,044	(26)	5,502
Net income after dividends on preferred and preference stock	—	—	—	761	—	761
Capital contributions from parent company	—	—	42	—	—	42
Other comprehensive income (loss)	—	—	—	—	(3)	(3)
Cash dividends on common stock	—	—	—	(550)	—	(550)
Balance at December 31, 2014	**31**	**1,222**	**2,304**	**2,255**	**(29)**	**5,752**
Net income after dividends on preferred and preference stock	**—**	**—**	**—**	**785**	**—**	**785**
Capital contributions from parent company	**—**	**—**	**37**	**—**	**—**	**37**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**(3)**	**(3)**
Cash dividends on common stock	**—**	**—**	**—**	**(571)**	**—**	**(571)**
Other	**—**	**—**	**—**	**(8)**	**—**	**(8)**
Balance at December 31, 2015	**31**	**$ 1,222**	**$ 2,341**	**$ 2,461**	**$ (32)**	**$ 5,992**

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

Index to the Notes to Financial Statements

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Alabama Power Company (the Company) is a wholly owned subsidiary of Southern Company, which is the parent company of four traditional operating companies, 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, Georgia Power, Gulf Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. The Company provides electricity to retail and wholesale customers within its traditional service territory located in the State of Alabama in addition to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary primarily for Southern Company's investments in leveraged leases 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 Farley.

The equity method is used for subsidiaries in which the Company has significant influence but does not control and for variable interest entities (VIEs) where the Company has an equity investment, but is not the primary beneficiary.

The Company is subject to regulation by the FERC and the Alabama 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.

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 in long-term debt totaling $39 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 Note 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 expenses of $20 million and accrued income tax of $2 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 $438 million, $400 million, and $340 million during 2015, 2014, and 2013, respectively. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the SEC. Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has an agreement with Southern Nuclear under which the following nuclear-related services are rendered to the Company at cost: general executive and advisory services, general operations, management and technical services, administrative services including procurement, accounting, employee relations, systems and procedures services, strategic planning and budgeting services, and other services with respect to business and operations. Costs for these services amounted to $243 million, $234 million, and $211 million during 2015, 2014, and 2013, respectively.

The Company jointly owns Plant Greene County with Mississippi Power. The Company has an agreement with Mississippi Power under which the Company operates Plant Greene County, and Mississippi Power reimburses the Company for its proportionate share of non-fuel expenses, which were $11 million in 2015, $13 million in 2014, and $13 million in 2013. Also, Mississippi Power reimburses the Company for any direct fuel purchases delivered from one of the Company's transfer facilities, which were $8 million in 2015, $34 million in 2014, and $27 million in 2013. See Note 4 for additional information.

The Company has an agreement with Gulf Power under which the Company has made transmission system upgrades to ensure firm delivery of energy under a non-affiliate PPA from a combined cycle plant located in Autauga County, Alabama. The transmission improvements were completed in 2014. The Company received $14 million in 2015 and expects to recover approximately $12 million a year from 2016 through 2023 through a tariff with Gulf Power.

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.

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

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

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)		
Deferred income tax charges	**$ 522**	$ 525	(a,k)
Loss on reacquired debt	**75**	80	(b)
Vacation pay	**66**	65	(c,j)
Under/(over) recovered regulatory clause revenues	**(97)**	57	(d)
Fuel-hedging losses	**55**	53	(e,j)
Other regulatory assets	**53**	49	(f)
Asset retirement obligations	**(40)**	(125)	(a)
Other cost of removal obligations	**(722)**	(744)	(a)
Deferred income tax credits	**(70)**	(72)	(a)
Nuclear outage	**53**	56	(d)
Natural disaster reserve	**(75)**	(84)	(h)
Other regulatory liabilities	**(8)**	(17)	(e,g)
Retiree benefit plans	**903**	882	(i,j)
Remaining net book value of retired assets	**76**	13	(l)
Total regulatory assets (liabilities), net	**$ 791**	$ 738	

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

(a) Asset retirement and removal assets and liabilities are recorded, deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 50 years. Asset retirement and removal assets and liabilities will be settled and trued up following completion of the related activities.

(b) Recovered over the remaining life of the original issue, which may range up to 50 years.

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

(d) Recorded and recovered or amortized as approved or accepted by the Alabama PSC over periods not exceeding 10 years.

(e) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed three and a half years. Upon final settlement, actual costs incurred are recovered through the energy cost recovery clause.

(f) Comprised of components including generation site selection/evaluation costs, PPA capacity, and other miscellaneous assets. Recorded as accepted by the Alabama PSC. Capitalized upon initialization of related construction projects, if applicable.

(g) Comprised of components including mine reclamation and remediation liabilities, fuel-hedging gains and nuclear fuel disposal fee. Recorded as accepted by the Alabama PSC. Mine reclamation and remediation liabilities will be settled following completion of the related activities. Nuclear fuel disposal fees are recorded as approved by the Alabama PSC related to potential future fees for nuclear waste disposal. The balance was transferred to Rate ECR in 2015. See Note 3 for additional information.

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

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

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

(k) Included in the deferred income tax charges are $17 million for 2015 and $18 million for 2014 for the retiree Medicare drug subsidy, which is recovered and amortized, as approved by the Alabama PSC, over the average remaining service period which may range up to 15 years.

(l) Recorded and amortized as approved by the Alabama PSC for a period up to 11 years.

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, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. The Company continuously monitors the under/over recovered balances and files for revised rates as required or when management deems appropriate, depending on the rate. See Note 3 under "Retail Regulatory Matters – Rate ECR" and "Retail Regulatory Matters – Rate CNP" for additional information.

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

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel.

See Note 3 under "Retail Regulatory Matters – Nuclear Waste Fund Fee Accounting Order" 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. Federal ITCs utilized are deferred and amortized to income over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

The Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and cost of equity funds used during construction.

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

	2015	2014
	(in millions)	
Generation	**$ 12,820**	$ 11,670
Transmission	**3,773**	3,579
Distribution	**6,432**	6,196
General	**1,713**	1,623
Plant acquisition adjustment	**12**	12
Total plant in service	**$ 24,750**	$ 23,080

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred or performed with the exception of nuclear refueling costs, which are recorded in accordance with specific Alabama PSC orders.

Nuclear Outage Accounting Order

In accordance with an Alabama PSC order, nuclear outage operations and maintenance expenses for the two units at Plant Farley are deferred to a regulatory asset when the charges actually occur and are then amortized over a subsequent 18-month period with the fall outage costs amortization beginning in January of the following year and the spring outage costs amortization beginning in July of the same year.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 2.9% in 2015, 3.3% in 2014 and 3.2% in 2013. Depreciation studies are conducted periodically to update the composite rates and the information is provided to the Alabama PSC and approved by the FERC. When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

In 2014, the Company submitted a depreciation study to the FERC and received authorization to use the recommended rates beginning January 2015. The study was also provided to the Alabama PSC. The new rates resulted in the decrease in the composite depreciation rate for 2015.

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 Alabama PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The liability for AROs primarily relates to the decommissioning of the Company's nuclear facility, Plant Farley, and facilities 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), principally ash ponds. In addition, the Company has retirement obligations related to various landfill sites, underground storage tanks, asbestos removal, disposal of polychlorinated biphenyls in certain transformers, and disposal of sulfur hexafluoride gas in certain substation breakers. The Company also has identified retirement obligations related to certain transmission and distribution facilities and certain wireless communication towers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets 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, as ordered by the Alabama PSC, and are reflected in the balance sheets. See "Nuclear Decommissioning" herein for additional information on amounts included in rates.

Details of the AROs included in the balance sheets are as follows:

	2015	2014
	(in millions)	
Balance at beginning of year	**$ 829**	$ 730
Liabilities incurred	**402**	1
Liabilities settled	**(3)**	(3)
Accretion	**53**	45
Cash flow revisions	**167**	56
Balance at end of year	**$ 1,448**	$ 829

The increase in liabilities incurred and cash flow revisions in 2015 is primarily related to the Company's AROs associated with the impact of the CCR Rule on its ash and gypsum facilities. 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. 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 cash flow revisions in 2014 are primarily related to the Company's AROs associated with asbestos at its steam generation facilities.

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 Alabama 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.

At December 31, 2015, investment securities in the Funds totaled $734 million, consisting of equity securities of $521 million, debt securities of $191 million, and $22 million of other securities. At December 31, 2014, investment securities in the Funds totaled $754 million, consisting of equity securities of $583 million, debt securities of $163 million, and $8 million of other securities. These amounts exclude receivables related to investment income and pending investment sales and payables related to pending investment purchases.

Sales of the securities held in the Funds resulted in cash proceeds of $438 million, $244 million, and $279 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 $8 million, which included $57 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 $54 million, which included $19 million related to unrealized gains 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 $120 million, which included $85 million related to unrealized losses 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.

Amounts previously recorded in internal reserves are being transferred into the Funds over periods approved by the Alabama PSC. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed a plan with the NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.

At December 31, the accumulated provisions for decommissioning were as follows:

	2015	2014
	(in millions)	
External trust funds	**$ 734**	$ 754
Internal reserves	**20**	21
Total	**$ 754**	$ 775

Site study costs is the estimate to decommission a facility as of the site study year. The estimated costs of decommissioning as of December 31, 2015 based on the most current study performed in 2013 for Plant Farley are as follows:

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

The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from the above estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates.

For ratemaking purposes, the Company's decommissioning costs are based on the site study. Significant assumptions used to determine these costs for ratemaking were an inflation rate of 4.5% and a trust earnings rate of 7.0%. The next site study is expected to be conducted in 2018.

Amounts previously contributed to the Funds are currently projected to be adequate to meet the decommissioning obligations. The Company will continue to provide site-specific estimates of the decommissioning costs and related projections of funds in the external trust to the Alabama PSC and, if necessary, would seek the Alabama PSC's approval to address any changes in a manner consistent with NRC and other applicable requirements.

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. All current construction costs are included in retail rates. The AFUDC composite rate as of December 31 was 8.7% in 2015, 8.8% in 2014, and 9.1% in 2013. AFUDC, net of income taxes, as a percent of net income after dividends on preferred and preference stock was 9.3% in 2015, 7.9% in 2014, and 5.4% in 2013.

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.

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

Generally, materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

Fuel Inventory

Fuel inventory includes the average cost of coal, natural gas, oil, transportation, and emissions allowances. Fuel is charged to inventory when purchased and then expensed, at weighted average cost, as used and recovered by the Company through energy cost recovery rates approved by the Alabama PSC. Emissions allowances granted by the 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 Alabama 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. If any, immaterial 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.

Variable Interest Entities

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

The Company has established a wholly-owned trust to issue preferred securities. See Note 6 under "Long-Term Debt Payable to an Affiliated Trust" for additional information. However, the Company is not considered the primary beneficiary of the trust. Therefore, the investment in the trust is reflected as other investments, and the related loan from the trust is reflected as long-term debt in the balance sheets.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 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 Alabama PSC and the FERC. For the year ending December 31, 2016, no other postretirement trusts contributions are expected.

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 rate – interest costs	**4.18%**	5.02%	4.27%
Discount rate – 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	**4.04%**	4.86%	4.06%
Discount rate – service costs	**4.40**	4.86	4.06
Expected long-term return on plan assets	**7.17**	7.34	7.36
Annual salary increase	**3.59**	3.59	3.59

Assumptions used to determine benefit obligations:	2015	2014
Pension plans		
Discount rate	**4.67%**	4.18%
Annual salary increase	**4.46**	3.59
Other postretirement benefit plans		
Discount rate	**4.51%**	4.04%
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 $51 million and $9 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	$ 29	$ (25)
Service and interest costs	1	(1)

Pension Plans

The total accumulated benefit obligation for the pension plans was $2.3 billion at December 31, 2015 and $2.4 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	**$ 2,592**	$ 2,112
Service cost	**59**	48
Interest cost	**106**	103
Benefits paid	**(120)**	(100)
Actuarial loss (gain)	**(131)**	429
Balance at end of year	**2,506**	2,592
Change in plan assets		
Fair value of plan assets at beginning of year	**2,396**	2,278
Actual return (loss) on plan assets	**(9)**	207
Employer contributions	**12**	11
Benefits paid	**(120)**	(100)
Fair value of plan assets at end of year	**2,279**	2,396
Accrued liability	**$ (227)**	$ (196)

At December 31, 2015, the projected benefit obligations for the qualified and non-qualified pension plans were $2.4 billion and $124 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	**$ 822**	$ 827
Other current liabilities	**(11)**	(10)
Employee benefit obligations	**(216)**	(186)

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	**$ 6**	$ 12	**$ 3**
Net (gain) loss	**816**	815	**40**
Regulatory assets	**$ 822**	$ 827	

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	**$ 827**	$ 476
Net (gain) loss	**56**	389
Reclassification adjustments:		
Amortization of prior service costs	**(6)**	(7)
Amortization of net gain (loss)	**(55)**	(31)
Total reclassification adjustments	**(61)**	(38)
Total change	**(5)**	351
Ending balance	**$ 822**	$ 827

Components of net periodic pension cost were as follows:

	2015	2014	2013
		(in millions)	
Service cost	**$ 59**	$ 48	$ 52
Interest cost	**106**	103	93
Expected return on plan assets	**(178)**	(168)	(157)
Recognized net loss	**55**	31	52
Net amortization	**6**	7	7
Net periodic pension cost	**$ 48**	$ 21	$ 47

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	$ 114
2017	119
2018	124
2019	129
2020	134
2021 to 2025	740

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	**$ 503**	$ 431
Service cost	**6**	5
Interest cost	**20**	20
Benefits paid	**(27)**	(27)
Actuarial loss (gain)	**(7)**	71
Plan amendment	**7**	—
Retiree drug subsidy	**3**	3
Balance at end of year	**505**	503
Change in plan assets		
Fair value of plan assets at beginning of year	**392**	389
Actual return (loss) on plan assets	**(6)**	23
Employer contributions	**1**	4
Benefits paid	**(24)**	(24)
Fair value of plan assets at end of year	**363**	392
Accrued liability	**$ (142)**	$ (111)

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	**$ 95**	$ 68
Other regulatory liabilities, deferred	**(13)**	(14)
Employee benefit obligations	**(142)**	(111)

Presented below are the amounts included in net regulatory assets (liabilities) 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	**$ 19**	$ 15	**$ 4**
Net (gain) loss	**63**	39	**2**
Net regulatory assets	**$ 82**	$ 54	

The changes in the balance of net regulatory assets (liabilities) 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)	
Net regulatory assets (liabilities):		
Beginning balance	**$ 54**	$ (15)
Net (gain) loss	**25**	73
Change in prior service costs	**8**	—
Reclassification adjustments:		
Amortization of prior service costs	**(3)**	(4)
Amortization of net gain (loss)	**(2)**	—
Total reclassification adjustments	**(5)**	(4)
Total change	**28**	69
Ending balance	**$ 82**	$ 54

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

	2015	2014	2013
		(in millions)	
Service cost	**$ 6**	$ 5	$ 6
Interest cost	**20**	20	19
Expected return on plan assets	**(26)**	(25)	(23)
Net amortization	**5**	4	5
Net periodic postretirement benefit cost	**$ 5**	$ 4	$ 7

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	$ 33	$ (3)	$ 30
2017	34	(3)	31
2018	34	(3)	31
2019	35	(4)	31
2020	36	(4)	32
2021 to 2025	184	(20)	164

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	48%	**45%**	48%
International equity	20	**20**	20
Domestic fixed income	24	**27**	26
Special situations	1	**1**	—
Real estate investments	4	**5**	4
Private equity	3	**2**	2
Total	100%	**100%**	100%

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns and interest rates, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices.

Investment Strategies

Detailed below is a description of the investment strategies for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Trust-owned life insurance (TOLI).*** Investments of the Company's taxable trusts aimed at minimizing the impact of taxes on the portfolio.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.
- ***Real estate investments.*** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 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*	$ 403	$ 168	$ —	$ —	$ 571
International equity*	294	244	—	—	538
Fixed income:					
U.S. Treasury, government, and agency bonds	—	112	—	—	112
Mortgage- and asset-backed securities	—	49	—	—	49
Corporate bonds	—	280	—	—	280
Pooled funds	—	123	—	—	123
Cash equivalents and other	—	36	—	—	36
Real estate investments	74	—	—	301	375
Private equity	—	—	—	157	157
Total	$ 771	$ 1,012	$ —	$ 458	$ 2,241

* 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*	$ 421	$ 174	$ —	$ —	$ 595
International equity*	264	244	—	—	508
Fixed income:					
U.S. Treasury, government, and agency bonds	—	173	—	—	173
Mortgage- and asset-backed securities	—	47	—	—	47
Corporate bonds	—	280	—	—	280
Pooled funds	—	127	—	—	127
Cash equivalents and other	1	163	—	—	164
Real estate investments	73	—	—	277	350
Private equity	—	—	—	141	141
Total	$ 759	$ 1,208	$ —	$ 418	$ 2,385

* 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.

As of December 31, 2015:	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*	$ 57	$ 8	$ —	$ —	$ 65
International equity*	14	12	—	—	26
Fixed income:					
U.S. Treasury, government, and agency bonds	—	8	—	—	8
Mortgage- and asset-backed securities	—	2	—	—	2
Corporate bonds	—	13	—	—	13
Pooled funds	—	6	—	—	6
Cash equivalents and other	1	2	—	—	3
Trust-owned life insurance	—	212	—	—	212
Real estate investments	5	—	—	14	19
Private equity	—	—	—	7	7
Total	$ 77	$ 263	$ —	$ 21	$ 361

* 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*	$ 76	$ 8	$ —	$ —	$ 84
International equity*	13	12	—	—	25
Fixed income:					
U.S. Treasury, government, and agency bonds	—	10	—	—	10
Mortgage- and asset-backed securities	—	2	—	—	2
Corporate bonds	—	14	—	—	14
Pooled funds	—	6	—	—	6
Cash equivalents and other	—	8	—	—	8
Trust-owned life insurance	—	217	—	—	217
Real estate investments	5	—	—	13	18
Private equity	—	—	—	7	7
Total	$ 94	$ 277	$ —	$ 20	$ 391

* 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 $22 million, $21 million, and $20 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 could 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 sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation.

Nuclear Fuel Disposal Costs

Acting through the DOE and pursuant to the Nuclear Waste Policy Act of 1982, the U.S. government entered into a contract with the Company that requires the DOE to dispose of spent nuclear fuel and high level radioactive waste generated at Plant Farley 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 has 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 $26 million. In November 2015, the Company applied the retail-related proceeds to offset the nuclear fuel expense under Rate ECR. See "Retail Regulatory Matters – Nuclear Waste Fund Accounting Order" herein for additional information. In December 2015, the Company credited the wholesale-related proceeds to each wholesale customer.

In March 2014, the Company filed an additional lawsuit against the U.S. government for the costs of continuing to store spent nuclear fuel at Plant Farley 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 this lawsuit. The final outcome of this matter cannot be determined at this time; however, no material impact on the Company's net income is expected.

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

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 RSE

The Alabama PSC has adopted Rate RSE that provides for periodic annual adjustments based upon the Company's projected weighted cost of equity (WCE) compared to an allowable range. Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Retail rates remain unchanged when the WCE ranges between 5.75% and 6.21%. Rate RSE adjustments for any two-year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0%. If the Company's actual retail return is above the allowed WCE range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail return fall below the WCE range.

In 2013, the Alabama PSC approved a revision to Rate RSE, effective for calendar year 2014. This revision established the WCE range of 5.75% to 6.21% with an adjusting point of 5.98% and provided eligibility for a performance-based adder of seven basis points, or 0.07%, to the WCE adjusting point if the Company (i) has an "A" credit rating equivalent with at least one of the recognized rating agencies or (ii) is in the top one-third of a designated customer value benchmark survey.

The Rate RSE increase for 2015 was 3.49% or $181 million annually, and was effective January 1, 2015. On November 30, 2015, the Company made its annual Rate RSE submission to the Alabama PSC of projected data for calendar year 2016. Projected earnings were within the specified WCE range; therefore, retail rates under Rate RSE remained unchanged for 2016.

Rate CNP

The Company's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service under Rate CNP. The Company may also recover retail costs associated with certificated PPAs under Rate CNP PPA. On March 3, 2015, the Alabama PSC issued a consent order that the Company leave in effect the current Rate CNP PPA factor for billings for the period April 1, 2015 through March 31, 2016. No adjustment to Rate CNP PPA is expected in 2016. As of December 31, 2015, the Company had an under recovered certificated PPA balance of $99 million which is included in deferred under recovered regulatory clause revenues in the balance sheet.

Rate CNP Environmental allowed for the recovery of the Company's retail costs associated with environmental laws, regulations, and other such mandates. On March 3, 2015, the Alabama PSC approved a modification to Rate CNP Environmental to include compliance costs for both environmental and non-environmental mandates. The recoverable non-environmental compliance costs result from laws, regulations, and other mandates directed at the utility industry involving the security, reliability, safety, sustainability, or similar considerations impacting the Company's facilities or operations. This modification to Rate CNP Environmental was effective March 20, 2015 with the revised rate now defined as Rate CNP Compliance. The Company was limited to recover $50 million of non-environmental compliance costs for the year 2015. Additional non-environmental compliance costs were recovered through Rate RSE. Customer rates were not impacted by this order in 2015; therefore, the modification increased the under recovered position for Rate CNP Compliance during 2015. Rate CNP Compliance is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Compliance costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital.

Rate CNP Compliance increased 1.5%, or $75 million annually, effective January 1, 2015. As of December 31, 2015, the Company had an under recovered compliance clause balance of $43 million, which is included in under recovered regulatory clause revenues in the balance sheet.

Rate ECR

The Company has established energy cost recovery rates under the Company's Rate ECR as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. The Company, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on the Company's net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per KWH. In December 2014, the Alabama PSC issued a consent order that the Company leave in effect for 2015 the Rate ECR factor of 2.681 cents per KWH.

On December 1, 2015, the Alabama PSC approved a decrease in the Company’s Rate ECR factor from 2.681 to 2.030 cents per KWH, 6.7%, or $370 million annually, based upon projected billings, effective January 1, 2016. The approved decrease in the Rate ECR factor will have no significant effect on the Company's net income, but will decrease operating cash flows related to fuel cost recovery in 2016 when compared to 2015. The rate will return to 2.681 cents per KWH in 2017 and 5.910 cents per KWH in 2018, absent a further order from the Alabama PSC.

The Company's over recovered fuel costs at December 31, 2015 totaled $238 million as compared to $47 million at December 31, 2014. At December 31, 2015, $238 million is included in other regulatory liabilities, current. The over recovered fuel costs at December 31, 2014 are included in deferred over recovered regulatory clause revenues. These classifications are based on estimates, which include such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any recovery or return of fuel costs.

Rate NDR

Based on an order from the Alabama PSC, the Company maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate NDR charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. The second component of the Rate NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 24-month period. The Alabama PSC order gives the Company authority to record a deficit balance in the NDR when costs of storm damage exceed any established reserve balance. Absent further Alabama PSC approval, the maximum total Rate NDR charge consisting of both components is $10 per month per non-residential customer account and $5 per month per residential customer account. The Company has the authority, based on an order from the Alabama PSC, to accrue certain additional amounts as circumstances warrant. The order allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million. The Company may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance the Company's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear.

As revenue from the Rate NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, the Rate NDR charge will not have an effect on net income but will impact operating cash flows.

Environmental Accounting Order

Based on an order from the Alabama PSC, the Company is allowed to establish a regulatory asset to record the unrecovered investment costs, including the unrecovered plant asset balance and the unrecovered costs, associated with site removal and closure associated with future unit retirements caused by environmental regulations. These costs are being amortized and recovered over the affected unit's remaining useful life, as established prior to the decision regarding early retirement through Rate CNP Compliance.

In April 2015, as part of its environmental compliance strategy, the Company retired Plant Gorgas Units 6 and 7 (200 MWs). Additionally, in April 2015, the Company ceased using coal at Plant Barry Units 1 and 2 (250 MWs), but such units will remain available on a limited basis with natural gas as the fuel source. In accordance with the joint stipulation entered in connection with a civil enforcement action by the EPA, the Company retired Plant Barry Unit 3 (225 MWs) in August 2015 and it is no longer available for generation. The Company expects to cease using coal at Plant Greene County Units 1 and 2 (300 MWs) and begin operating those units solely on natural gas by April 2016.

In accordance with this accounting order from the Alabama PSC, the Company transferred the unrecovered plant asset balances to a regulatory asset at their respective retirement dates. The regulatory asset will be amortized and recovered through Rate CNP Compliance over the remaining useful lives, as established prior to the decision for retirement. As a result, these decisions will not have a significant impact on the Company's financial statements.

Nuclear Waste Fund Accounting Order

In 2013, the U.S. District Court for the District of Columbia ordered the DOE to cease collecting spent fuel depositary fees from nuclear power plant operators until such time as the DOE either complies with the Nuclear Waste Policy Act of 1982 or until the U.S. Congress enacts an alternative waste management plan. The DOE formally set the fee to zero effective May 16, 2014.

In August 2014, the Alabama PSC issued an order to provide for the continued recovery from customers of amounts associated with the permanent disposal of nuclear waste from the operation of Plant Farley. In accordance with the order, effective May 16, 2014, the Company was authorized to recover from customers an amount equal to the prior fee and to record the amounts in a regulatory liability account (approximately $14 million annually). On December 1, 2015, the Alabama PSC issued an order for the Company to discontinue recording the amounts recovered from customers in a regulatory liability account and transfer amounts recorded in the regulatory liability to Rate ECR. On December 1, 2015, the Company transferred $20 million from the regulatory liability to Rate ECR to offset fuel expense.

Cost of Removal Accounting Order

In accordance with an accounting order issued in November 2014 by the Alabama PSC, in December 2014, the Company fully amortized the balance of $123 million in certain regulatory asset accounts and offset this amortization expense with the amortization of $120 million of the regulatory liability for other cost of removal obligations. The regulatory asset accounts fully amortized and terminated as of December 31, 2014 represented costs previously deferred under a compliance and pension cost accounting order as well as a non-nuclear outage accounting order, which were approved by the Alabama PSC in 2012 and 2013, respectively. Approximately $95 million of non-nuclear outage costs and $28 million of compliance and pension costs were fully amortized in December 2014.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Georgia Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 MWs, as well as associated transmission facilities. The capacity of these units is sold equally to the Company and Georgia Power under a power contract. The Company and Georgia Power make payments sufficient to provide for the operating expenses, taxes, interest expense, and ROE. The Company's share of purchased power totaled $76 million in 2015, $84 million in 2014, and $88 million in 2013 and is included in "Purchased power from affiliates" in the statements of income. The Company accounts for SEGCO using the equity method.

In addition, the Company has guaranteed unconditionally the obligation of SEGCO under an installment sale agreement for the purchase of certain pollution control facilities at SEGCO's generating units, pursuant to which $25 million principal amount of pollution control revenue bonds are outstanding. The Company has guaranteed $100 million principal amount of unsecured senior notes issued by SEGCO for general corporate purposes. These senior notes mature on December 1, 2018. Georgia Power has agreed to reimburse the Company for the pro rata portion of such obligations corresponding to its then proportionate ownership of stock of SEGCO if the Company is called upon to make such payment under its guarantee.

At December 31, 2015, the capitalization of SEGCO consisted of $118 million of equity and $125 million of long-term debt on which the annual interest requirement is $3 million. In addition, SEGCO had short-term debt outstanding of $52 million. SEGCO paid an immaterial amount of dividends in 2015 compared to $3 million in 2014 and $7 million in 2013, of which one-half of each was paid to the Company. In addition, the Company recognizes 50% of SEGCO's net income.

SEGCO added natural gas as a fuel source for 1,000 MWs of its generating capacity in 2015. In April 2016, natural gas will become the primary fuel source. The Company, which owns and operates a generating unit adjacent to the SEGCO generating units, has entered into a joint ownership agreement with SEGCO for the ownership of the gas pipeline. The Company owns 14% of the pipeline with the remaining 86% owned by SEGCO.

In addition to the Company's ownership of SEGCO and joint ownership of the natural gas pipeline, the Company's percentage ownership and investment in jointly-owned coal-fired generating plants at December 31, 2015 were as follows:

Facility	Total MW Capacity	Company Ownership	Plant in Service	Accumulated Depreciation	Construction Work in Progress
				(in millions)	
Greene County	500	60.00% (1)	$ 159	$ 97	$ 20
Plant Miller					
Units 1 and 2	1,320	91.84% (2)	1,518	587	63

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

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

The Company has contracted to operate and maintain the jointly-owned facilities as agent for their co-owners. The Company's proportionate share of its plant operating expenses is included in operating expenses in the statements of income and the Company is responsible for providing its own financing.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and 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	**$ 110**	$ 198	$ 243
Deferred	**320**	225	160
	430	423	403
State —			
Current	**8**	44	36
Deferred	**68**	45	39
	76	89	75
Total	**$ 506**	$ 512	$ 478

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	**$ 3,917**	$ 3,429
Property basis differences	**456**	457
Premium on reacquired debt	**28**	30
Employee benefit obligations	**200**	215
Regulatory assets associated with employee benefit obligations	**375**	366
Asset retirement obligations	**289**	59
Regulatory assets associated with asset retirement obligations	**312**	285
Other	**175**	157
Total	**5,752**	4,998
Deferred tax assets —		
Federal effect of state deferred taxes	**242**	219
Unbilled fuel revenue	**39**	42
Storm reserve	**23**	27
Employee benefit obligations	**407**	400
Other comprehensive losses	**20**	19
Asset retirement obligations	**600**	344
Other	**180**	90
Total	**1,511**	1,141
Accumulated deferred income taxes, net	**$ 4,241**	$ 3,857

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 expenses of $20 million and accrued income tax of $2 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, the tax-related regulatory assets to be recovered from customers were $523 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, the tax-related regulatory liabilities to be credited to customers were $70 million. These liabilities are primarily attributable to 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 $8 million in 2015, 2014 and 2013. At December 31, 2015, all ITCs available to reduce federal income taxes payable had been utilized.

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	**3.8**	4.4	4.0
Non-deductible book depreciation	**1.2**	1.1	1.0
Differences in prior years' deferred and current tax rates	**(0.1)**	(0.1)	(0.1)
AFUDC equity	**(1.6)**	(1.3)	(0.9)
Other	**0.1**	(0.1)	(0.1)
Effective income tax rate	**38.4%**	39.0%	38.9%

Unrecognized Tax Benefits

The Company has no material unrecognized tax benefits for 2015 or 2014. The Company classifies interest on tax uncertainties as interest expense. Accrued interest for unrecognized tax benefits was immaterial and 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. 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

Long-Term Debt Payable to an Affiliated Trust

The Company has formed a wholly-owned trust subsidiary for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the Company through the issuance of junior subordinated notes totaling $206 million as of December 31, 2015 and 2014, which constitute substantially all of the assets of this trust and are reflected in the balance sheets as long-term debt payable. The Company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the trust's payment obligations with respect to these securities. At December 31, 2015 and 2014, trust preferred securities of $200 million were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for this trust and the related securities.

Securities Due Within One Year

At December 31, 2015, the Company had $200 million of senior notes and pollution control revenue bonds due within one year. At December 31, 2014, the Company had $454 million of senior notes and pollution control revenue bonds due within one year.

Maturities through 2020 applicable to total long-term debt are as follows: $200 million in 2016; $562 million in 2017; $201 million in 2019; and $251 million in 2020. There are no material scheduled maturities in 2018.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds or installment purchases of pollution control and solid waste disposal facilities financed by funds derived from sales by public authorities of revenue bonds. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The Company incurred no obligations related to the issuance of pollution control revenue bonds in 2015.

In April 2015, Alabama Power purchased and held $80 million aggregate principal amount of Industrial Development Board of the City of Mobile, Alabama Pollution Control Revenue Bonds (Alabama Power Company Barry Plant Project), Series 2007-B. Alabama Power reoffered these bonds to the public in May 2015.

The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2015 and 2014 was $1.1 billion and $1.2 billion, respectively.

Senior Notes

In March 2015, the Company issued $550 million aggregate principal amount of Series 2015A 3.750% Senior Notes due March 1, 2045. The proceeds were used to redeem $250 million aggregate principal amount of Series DD 5.650% Senior Notes due March 15, 2035 and for general corporate purposes, including the Company's continuous construction program.

In April 2015, the Company issued $175 million additional aggregate principal amount of its Series 2015A 3.750% Senior Notes due March 1, 2045 (Additional Series 2015A Senior Notes) and $250 million aggregate principal amount of its Series 2015B 2.800% Senior Notes due April 1, 2025 (Series 2015B Senior Notes). A portion of the proceeds of the additional Series 2015A Senior Notes and the Series 2015B Senior Notes were used in May 2015 to redeem certain classes of the Company's preferred and preference stock plus accrued and unpaid dividends to the redemption date, and the remaining net proceeds were used for general corporate purposes, including the Company's continuous construction program. See "Redeemable Preferred Stock" herein for additional information.

At December 31, 2015 and 2014, the Company had $5.6 billion and $5.3 billion of senior notes outstanding, respectively. As of December 31, 2015, the Company did not have any outstanding secured debt.

Subsequent to December 31, 2015, the Company issued $400 million aggregate principal amount of Series 2016A 4.30% Senior Notes due January 2, 2046. The proceeds were used to repay at maturity $200 million aggregate principal amount of Series FF 5.20% Senior Notes due January 15, 2016 and for general corporate purposes, including the Company's continuous construction program.

Redeemable Preferred and Preference Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized and outstanding. The Company's preferred stock and Class A preferred stock, without preference between classes, rank senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary and involuntary dissolution. The preferred stock and Class A preferred stock of the Company contain a feature that allows the holders to elect a majority of the Company's board of directors if preferred dividends are not paid for four consecutive quarters. Because such a potential redemption-triggering event is not solely within the control of the Company, the preferred stock and Class A preferred stock is presented as "Redeemable Preferred Stock" in a manner consistent with temporary equity under applicable accounting standards. The preference stock does not contain such a provision that would allow the holders to elect a majority of the Company's board. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution.

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

Preferred/Preference Stock	Par Value/ Stated Capital Per Share	Shares Outstanding	Redemption Price Per Share
4.92% Preferred Stock	$100	80,000	$103.23
4.72% Preferred Stock	$100	50,000	$102.18
4.64% Preferred Stock	$100	60,000	$103.14
4.60% Preferred Stock	$100	100,000	$104.20
4.52% Preferred Stock	$100	50,000	$102.93
4.20% Preferred Stock	$100	135,115	$105.00
5.83% Class A Preferred Stock	$25	1,520,000	Stated Capital
6.450% Preference Stock	$25	6,000,000	*
6.500% Preference Stock	$25	2,000,000	*

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

In May 2015, the Company redeemed 6.48 million shares ($162 million aggregate stated capital) of the Company's 5.20% Class A Preferred Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date and 4.0 million shares ($100 million aggregate stated capital) of the Company's 5.30% Class A Preferred Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date. Additionally, the $5 million of issuance costs were transferred from redeemable preferred stock to common stockholder's equity upon redemption. Also during May 2015, the Company redeemed 6.0 million shares ($150 million aggregate stated capital) of the Company's 5.625% Series Preference Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date. There were no changes for the years ended December 31, 2014 and 2013 in redeemable preferred stock or preference stock of the Company.

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, committed credit arrangements with banks were as follows:

Expires					Due Within One Year	
2016	2018	2020	Total	Unused	Term Out	No Term Out
	(in millions)		*(in millions)*		*(in millions)*	
$ 40	$ 500	$ 800	$ 1,340	$ 1,340	$ —	$ 40

As reflected in the table above, in August 2015, the Company amended and restated its multi-year credit arrangements, which, among other things, extended the maturity dates from 2018 to 2020. In September 2015, the Company entered into a new $500 million three-year credit arrangement which replaced a majority of the Company's bilateral credit arrangements.

Most of the bank credit arrangements require payment of a commitment fee based on the unused portion of the commitments or the maintenance of compensating balances with the banks. Commitment fees average less than $^{1}/_{10}$ of 1% for the Company. Compensating balances are not legally restricted from withdrawal.

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

Most of the Company's bank credit arrangements contain covenants that limit the Company's debt to 65% of total capitalization, as defined in the arrangements. For purposes of calculating these covenants, any long-term notes payable to affiliated trusts are excluded from debt but included in capitalization. Exceeding this debt level would result in a default under the credit arrangements. At December 31, 2015, the Company was in compliance with the debt limit covenants.

A portion of the unused credit with banks is allocated to provide liquidity support to the Company's pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support was $810 million as of December 31, 2015. In addition, at December 31, 2015, the Company had $80 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

The Company borrows through commercial paper programs that have the liquidity support of the committed bank credit arrangements described above. The Company may also make short-term borrowings through various other arrangements with banks. At December 31, 2015 and 2014, there was no short-term debt outstanding. At December 31, 2015, the Company had regulatory approval to have outstanding up to $2.1 billion of short-term borrowings.

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement and delivery of fossil and nuclear fuel which are not recognized on the balance sheets. In 2015, 2014, and 2013, the Company incurred fuel expense of $1.3 billion, $1.6 billion, and $1.6 billion, respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

In addition, the Company has entered into various long-term commitments for the purchase of capacity and electricity, some of which are accounted for as operating leases. Total capacity expense under PPAs accounted for as operating leases was $38 million, $37 million, and $30 million for 2015, 2014, and 2013, respectively. Total estimated minimum long-term obligations at December 31, 2015 were as follows:

	Operating Lease PPAs
	(in millions)
2016	$ 39
2017	40
2018	41
2019	43
2020	44
2021 and thereafter	93
Total commitments	$ 300

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

The Company has entered into rental agreements for coal railcars, vehicles, and other equipment with various terms and expiration dates. Total rent expense was $19 million in 2015, $18 million in 2014, and $21 million in 2013. Of these amounts, $13 million, $14 million, and $18 million for 2015, 2014, and 2013, respectively, relate to the railcar leases and are recoverable through the Company's Rate ECR. As of December 31, 2015, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Railcars	Vehicles & Other	Total
		(in millions)	
2016	$ 13	$ 6	$ 19
2017	8	5	13
2018	5	4	9
2019	5	4	9
2020	5	4	9
2021 and thereafter	13	—	13
Total	$ 49	$ 23	$ 72

In addition to the above rental commitments payments, the Company has potential obligations upon expiration of certain leases with respect to the residual value of the leased property. These leases have terms expiring through 2023 with maximum obligations under these leases of $4 million in 2016 and $12 million in 2021 and thereafter. There are no obligations under these leases in 2017, 2018, 2019, and 2020. At the termination of the leases, the lessee may either exercise its purchase option, or the property can be sold to a third party. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligations.

Guarantees

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

8. STOCK COMPENSATION

Stock-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 881 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 2,027,298 shares and 1,319,038 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 $8 million, $21 million, and $11 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $3 million, $8 million, and $4 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 $33 million and $26 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 214,709, 176,070, and 141,355, 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 $46.42, $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 $13 million, $5 million, and $5 million, respectively, with the related tax benefit also recognized in income of $5 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 Farley. The Act provides funds up to $13.5 billion for public liability claims that could arise from a single nuclear incident. Plant Farley is insured against this liability to a maximum of $375 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. The Company could be assessed up to $127 million per incident for each licensed reactor it operates but not more than an aggregate of $19 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for the Company is $255 million per incident but not more than an aggregate of $38 million to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due no later than September 10, 2018.

The Company is a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $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 and has elected a 12-week deductible waiting period.

Under each of the NEIL policies, members are subject to assessments each year if losses exceed the accumulated funds available to the insurer. The current maximum annual assessments for the Company under the NEIL policies would be $55 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)**	**Net Asset Value as a Practical Expedient (NAV)**	**Total**
			(in millions)		
Assets:					
Energy-related derivatives	$ —	$ 1	$ —	$ —	$ 1
Nuclear decommissioning trusts:(*)					
Domestic equity	359	68	—	—	427
Foreign equity	47	47	—	—	94
U.S. Treasury and government agency securities	—	27	—	—	27
Corporate bonds	11	135	—	—	146
Mortgage and asset backed securities	—	18	—	—	18
Private equity	—	—	—	17	17
Other	—	5	—	—	5
Cash equivalents	68	—	—	—	68
Total	$ 485	$ 301	$ —	$ 17	$ 803
Liabilities:					
Interest rate derivatives	$ —	$ 15	$ —	$ —	$ 15
Energy-related derivatives	—	55	—	—	55
Total	$ —	$ 70	$ —	$ —	$ 70

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

As of December 31, 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)**	**Net Asset Value as a Practical Expedient (NAV)**	**Total**
			(in millions)		
Assets:					
Energy-related derivatives	$ —	$ 1	$ —	$ —	$ 1
Nuclear decommissioning trusts:(*)					
Domestic equity	403	83	—	—	486
Foreign equity	34	63	—	—	97
U.S. Treasury and government agency securities	—	34	—	—	34
Corporate bonds	—	111	—	—	111
Mortgage and asset backed securities	—	18	—	—	18
Private equity	—	—	—	3	3
Other	—	5	—	—	5
Cash equivalents	162	—	—	—	162
Total	$ 599	$ 315	$ —	$ 3	$ 917
Liabilities:					
Interest rate derivatives	$ —	$ 8	$ —	$ —	$ 8
Energy-related derivatives	—	53	—	—	53
Total	$ —	$ 61	$ —	$ —	$ 61

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

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. See Note 1 under "Nuclear Decommissioning" for additional information.

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.

The Company early adopted ASU 2015-07 effective December 31, 2015. As required, disclosures in the paragraphs and table below are limited to only those investments in funds that are measured at net asset value as a practical expedient. In accordance with ASU 2015-07, previously reported amounts have been conformed to the current presentation.

As of December 31, 2015 and 2014, the fair value measurements of private equity investments held in the nuclear decommissioning trusts that are calculated at net asset value per share (or its equivalent) as a practical expedient, as well as the nature and risks of those investments, were as follows:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
	(in millions)			
As of December 31, 2015	**$ 17**	**$ 28**	**Not Applicable**	**Not Applicable**
As of December 31, 2014	$ 3	$ 7	Not Applicable	Not Applicable

Private equity funds include a fund-of-funds that invests in high quality private equity funds across several market sectors, a fund that invests in real estate assets, and a fund that acquires companies to create resale value. Private equity funds do not have redemption rights. Distributions from these funds will be received as the underlying investments in the funds are liquidated. Liquidations of these investments are expected to occur at various times over the next ten years.

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	**$ 6,849**	**$ 7,192**
2014	$ 6,586	$ 7,321

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates 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 fuel-hedging programs, implemented per the guidelines of the Alabama PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

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 programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the energy cost recovery clause.
- *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 for the Company, together with the longest hedge date over which it is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest date for derivatives not designated as hedges, were as follows:

Net Purchased mmBtu	Longest Hedge Date	Longest Non-Hedge Date
(in millions)		
50	2018	—

Interest Rate Derivatives

The Company may also enter into interest rate derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to earnings.

At December 31, 2015, the following interest rate derivative was 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 Forecasted Debt					
	$ 200	3-month LIBOR	2.93%	October 2025	$ (15)

The estimated pre-tax 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 that are expected to be amortized into earnings through 2035.

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	**$ 1**	$ 1	Liabilities from risk management activities	**$ 40**	$ 32
	Other deferred charges and assets	**—**	—	Other deferred credits and liabilities	**15**	21
Total derivatives designated as hedging instruments for regulatory purposes		**$ 1**	$ 1		**$ 55**	$ 53
Derivatives designated as hedging instruments in cash flow hedges						
Interest rate derivatives:	Other current assets	**$ —**	**$ —**	Liabilities from risk management activities	**$ 15**	$ 8
Total		**$ 1**	$ 1		**$ 70**	$ 61

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 contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Amounts related to energy-related derivative contracts at December 31, 2015 and 2014 are presented in the following tables. Interest rate derivatives presented in the tables above do not have amounts available for offset and are therefore excluded from the offsetting disclosure table below.

Fair Value					
Assets	**2015**	2014	**Liabilities**	**2015**	2014
	(in millions)			*(in millions)*	
Energy-related derivatives presented in the Balance Sheet [(a)]	**$ 1**	$ 1	Energy-related derivatives presented in the Balance Sheet [(a)]	**$ 55**	$ 53
Gross amounts not offset in the Balance Sheet [(b)]	**(1)**	—	Gross amounts not offset in the Balance Sheet [(b)]	**(1)**	—
Net energy-related derivative assets	**$ —**	$ 1	**Net energy-related derivative liabilities**	**$ 54**	$ 53

(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 effect 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	**$ (40)**	$ (32)	Other current liabilities	**$ 1**	$ 1
	Other regulatory assets, deferred	**(15)**	(21)	Other regulatory liabilities, deferred	**—**	—
Total energy-related derivative gains (losses)		**$ (55)**	$ (53)		**$ 1**	$ 1

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

Derivatives in Cash Flow Hedging Relationships	**Gain (Loss) Recognized in OCI on Derivative (Effective Portion)**			**Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)**			
					Amount		
Derivative Category	**2015**	2014	2013	**Statements of Income Location**	**2015**	2014	2013
	(in millions)				*(in millions)*		
Interest rate derivatives	**$ (7)**	$ (8)	$ —	Interest expense, net of amounts capitalized	**$ (3)**	$ (3)	$ (3)

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

For the years ended December 31, 2015, 2014, and 2013, the pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was not material.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2015, the Company's collateral posted with its derivative counterparties was not material.

At December 31, 2015, the fair value of derivative liabilities with contingent features was $16 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	**$ 1,401**	**$ 346**	**$ 169**
June 2015	**1,455**	**398**	**200**
September 2015	**1,695**	**555**	**295**
December 2015	**1,217**	**264**	**121**
March 2014	$ 1,508	$ 381	$ 187
June 2014	1,437	357	173
September 2014	1,669	520	282
December 2014	1,328	267	119

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

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

		2015		2014		2013		2012		2011
Operating Revenues (in millions)	**$**	**5,768**	$	5,942	$	5,618	$	5,520	$	5,702
Net Income After Dividends on Preferred and Preference Stock (in millions)	**$**	**785**	$	761	$	712	$	704	$	708
Cash Dividends on Common Stock (in millions)	**$**	**571**	$	550	$	644	$	684	$	774
Return on Average Common Equity (percent)		**13.37**		13.52		13.07		13.10		13.19
Total Assets (in millions)[(a)(b)]	**$**	**21,721**	$	20,493	$	19,185	$	18,647	$	18,397
Gross Property Additions (in millions)	**$**	**1,492**	$	1,543	$	1,204	$	940	$	1,016
Capitalization (in millions):										
Common stock equity	**$**	**5,992**	$	5,752	$	5,502	$	5,398	$	5,342
Preference stock		**196**		343		343		343		343
Redeemable preferred stock		**85**		342		342		342		342
Long-term debt[(a)]		**6,654**		6,137		6,195		5,890		5,586
Total (excluding amounts due within one year)	**$**	**12,927**	$	12,574	$	12,382	$	11,973	$	11,613
Capitalization Ratios (percent):										
Common stock equity		**46.4**		45.8		44.4		45.1		46.0
Preference stock		**1.5**		2.7		2.8		2.9		3.0
Redeemable preferred stock		**0.7**		2.7		2.7		2.9		2.9
Long-term debt[(a)]		**51.4**		48.8		50.1		49.1		48.1
Total (excluding amounts due within one year)		**100.0**		100.0		100.0		100.0		100.0
Customers (year-end):										
Residential		**1,253,875**		1,247,061		1,241,998		1,237,730		1,231,574
Commercial		**197,920**		197,082		196,209		196,177		196,270
Industrial		**6,056**		6,032		5,851		5,839		5,844
Other		**757**		753		751		748		746
Total		**1,458,608**		1,450,928		1,444,809		1,440,494		1,434,434
Employees (year-end)		**6,986**		6,935		6,896		6,778		6,632

(a) A reclassification of debt issuance costs from Total Assets to Long-term debt of $40 million, $38 million, $39 million, and $47 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 $20 million, $27 million, $27 million, and $33 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.

SELECTED FINANCIAL AND OPERATING DATA 2011-2015 (continued)
Alabama Power Company 2015 Annual Report

	2015	2014	2013	2012	2011
Operating Revenues (in millions):					
Residential	**$ 2,207**	$ 2,209	$ 2,079	$ 2,068	$ 2,144
Commercial	**1,564**	1,533	1,477	1,491	1,495
Industrial	**1,436**	1,480	1,369	1,346	1,306
Other	**27**	27	27	28	27
Total retail	**5,234**	5,249	4,952	4,933	4,972
Wholesale — non-affiliates	**241**	281	248	277	287
Wholesale — affiliates	**84**	189	212	111	244
Total revenues from sales of electricity	**5,559**	5,719	5,412	5,321	5,503
Other revenues	**209**	223	206	199	199
Total	**$ 5,768**	$ 5,942	$ 5,618	$ 5,520	$ 5,702
Kilowatt-Hour Sales (in millions):					
Residential	**18,082**	18,726	17,920	17,612	18,650
Commercial	**14,102**	14,118	13,892	13,963	14,173
Industrial	**23,380**	23,799	22,904	22,158	21,666
Other	**201**	211	211	214	214
Total retail	**55,765**	56,854	54,927	53,947	54,703
Wholesale — non-affiliates	**3,567**	3,588	3,711	4,196	4,330
Wholesale — affiliates	**4,515**	6,713	7,672	4,279	7,211
Total	**63,847**	67,155	66,310	62,422	66,244
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**12.21**	11.80	11.60	11.74	11.50
Commercial	**11.09**	10.86	10.63	10.68	10.55
Industrial	**6.14**	6.22	5.98	6.07	6.03
Total retail	**9.39**	9.23	9.02	9.14	9.09
Wholesale	**4.02**	4.56	4.04	4.58	4.60
Total sales	**8.71**	8.52	8.16	8.52	8.31
Residential Average Annual Kilowatt-Hour Use Per Customer	**14,454**	15,051	14,451	14,252	15,138
Residential Average Annual Revenue Per Customer	**$ 1,764**	$ 1,775	$ 1,676	$ 1,674	$ 1,740
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**11,797**	12,222	12,222	12,222	12,222
Maximum Peak-Hour Demand (megawatts):					
Winter	**12,162**	11,761	9,347	10,285	11,553
Summer	**11,292**	11,054	10,692	11,096	11,500
Annual Load Factor (percent)	**58.4**	61.4	64.9	61.3	60.6
Plant Availability (percent)*:					
Fossil-steam	**81.5**	82.5	87.3	88.6	88.7
Nuclear	**92.1**	93.3	90.7	94.5	94.7
Source of Energy Supply (percent):					
Coal	**49.1**	49.0	50.0	48.2	52.5
Nuclear	**21.3**	20.7	20.3	22.6	20.8
Hydro	**5.6**	5.5	8.1	4.1	4.6
Gas	**14.6**	15.4	15.7	16.8	15.3
Purchased power —					
From non-affiliates	**4.4**	3.6	2.9	2.0	0.9
From affiliates	**5.0**	5.8	3.0	6.3	5.9
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
Alabama Power Company 2015 Annual Report

Directors

Whit Armstrong
Managing Member,
Creeke Capital Investments, LLC

Ralph D. Cook[1]
Of Counsel,
Hare, Wynn, Newell & Newton, LLP

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

Mark A. Crosswhite
Chairman, President, and CEO,
Alabama Power Company

O.B. Grayson Hall, Jr.[2]
Chairman, President and CEO,
Regions Financial Corporation

Anthony A. Joseph
Shareholder,
Maynard, Cooper & Gale, P.C.

Patricia M. King
Chairman,
Sunny King Automotive Group

James K. Lowder
Chairman,
The Colonial Company

Malcolm Portera[1]
Partner,
Portera and Associates

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

Catherine J. Randall
Chairman,
Pettus Randall Holdings, LLC

C. Dowd Ritter
Retired Chairman and CEO,
Regions Financial Corporation

James H. Sanford[1]
Chairman,
HOME Place Farms, Inc.

R. Mitchell Shackleford III[2]
Vice President,
Canfor Western U.S. South Operations

Officers

Mark A. Crosswhite
Chairman, President, and CEO

Gregory J. Barker[3]
Executive Vice President

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

Zeke W. Smith
Executive Vice President

Steven R. Spencer[4]
Executive Vice President

Matthew W. Bowden[3]
Senior Vice President and General Counsel

James P. Heilbron
Senior Vice President and Senior Production Officer

John O. Hudson III[3]
Senior Vice President

Gordon G. Martin[5]
Senior Vice President

Anita Allcorn-Walker
Vice President and Comptroller

Ronald Q. Patterson
Vice President and Assistant Treasurer

Susan B. Comensky[3]
Vice President

Stephanie Kirijan Cooper[3]
Vice President

C. David Cox
Vice President

Mark S. Crews
Vice President

Daniel K. Glover
Vice President

R. Myrk Harkins
Vice President

Richard O. Hutto
Vice President

Stacy R. Kilcoyne
Vice President

Barbara J. Knight[6, 7]
Vice President and Senior Adviser to the Chairman, President and CEO

R. Scott Moore
Vice President

Kenneth F. Novak
Vice President

J. Jeffrey Peoples[8]
Vice President

Jonathan K. Porter
Vice President

Quentin P. Riggins
Vice President

Leslie L. Sanders
Vice President

R. Michael Saxon
Vice President

Don A. Scivley
Vice President

Julia H. Segars
Vice President

Nicholas C. Sellers[9]
Vice President

Anthony A. Smoke
Vice President

Robert L. Weaver
Vice President

Ceila H. Shorts
Corporate Secretary

Wendy M. Hoomes
Assistant Comptroller

Melissa K. Caen
Assistant Secretary and Assistant Treasurer

Amy E. Blankenship
Assistant Secretary

Kimberly L. Jackson[8]
Assistant Secretary

Christopher R. Blake
Assistant Treasurer

Brian E. George
Assistant Treasurer

[1] Retiring effective 4/2016
[2] Elected effective 7/2015
[3] Elected effective 2/2016
[4] Resigning effective 4/2016
[5] Elected effective 2/2016 (previously served as Senior Vice President and General Counsel)
[6] Appointed 12/2015
[7] Retiring effective 4/2016
[8] Elected 12/2015
[9] Resigned effective 2/2016

CORPORATE INFORMATION
Alabama Power Company 2015 Annual Report

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

Profile
The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Alabama and to wholesale customers in the Southeast. The Company sells electricity to more than 1.4 million customers. In 2015, retail energy sales accounted for 87% percent of the Company's total sales of 64 billion kilowatt-hours.

The Company is a wholly-owned subsidiary of The Southern Company, which is the parent company of four traditional operating companies and Southern Power Company. There is no established public trading market for the Company's common stock.

Trustee, Registrar, and Paying Agent
All series of Senior Notes and Trust Preferred Securities
Regions Bank
Corporate Trust
1900 5th Avenue North, 25th Floor
Birmingham, AL 35203

Registrar, Transfer Agent, and Dividend Paying Agent
All series of Preferred 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

Number of Preferred Shareholders of record as of December 31, 2015 was 1,233.

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	$142,820	$137,390
Second	142,820	137,390
Third	142,820	137,390
Fourth	142,820	137,390

Form 10-K
A copy of the Form 10-K as filed with the Securities and Exchange Commission will be provided upon written request to the office of the Corporate Secretary. For additional information, contact the office of the Corporate Secretary at (205) 257-2619.

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