ALABAMA POWER CO
Form 10-K
February 22, 2017

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2016

OR

.. TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Transition Period from to

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-3526	The Southern Company (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-0690070
1-3164	Alabama Power Company (An Alabama Corporation) 600 North 18th Street Birmingham, Alabama 35291 (205) 257-1000	63-0004250
1-6468	Georgia Power Company (A Georgia Corporation) 241 Ralph McGill Boulevard, N.E. Atlanta, Georgia 30308 (404) 506-6526	58-0257110
001-31737	Gulf Power Company (A Florida Corporation) One Energy Place Pensacola, Florida 32520 (850) 444-6111	59-0276810
001-11229	Mississippi Power Company (A Mississippi Corporation) 2992 West Beach Boulevard Gulfport, Mississippi 39501 (228) 864-1211	64-0205820
001-37803	Southern Power Company (A Delaware Corporation)	58-2598670

	30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	
1-14174	Southern Company Gas (A Georgia Corporation) Ten Peachtree Place, N.E. Atlanta, Georgia 30309 (404) 584-4000	58-2210952

Securities registered pursuant to Section 12(b) of the Act:[1]

Each of the following classes or series of securities registered pursuant to Section 12(b) of the Act is listed on the New York Stock Exchange.

Title of each class	Registrant
Common Stock, $5 par value	The Southern Company
Junior Subordinated Notes, $25 denominations 6.25% Series 2015A due 2075 5.25% Series 2016A due 2076	
Class A preferred stock, cumulative, $25 stated capital 5.83% Series	Alabama Power Company
Class A preferred stock, non-cumulative, Par value $25 per share 6 1/8% Series	Georgia Power Company
Depositary preferred shares, each representing one-fourth of a share of preferred stock, cumulative, $100 par value 5.25% Series	Mississippi Power Company
Senior Notes 1.000% Series 2016A due 2022 1.850% Series 2016B due 2026	Southern Power Company

Securities registered pursuant to Section 12(g) of the Act:[1]

Title of each class			Registrant
Preferred stock, cumulative, $100 par value			Alabama Power Company
4.20% Series	4.60% Series	4.72% Series	
4.52% Series	4.64% Series	4.92% Series	

Preferred stock, cumulative, $100 par value	Mississippi Power Company
4.40% Series 4.60% Series 4.72% Series	

1 As of December 31, 2016.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Registrant	Yes	No
The Southern Company	X	
Alabama Power Company	X	
Georgia Power Company	X	
Gulf Power Company		X
Mississippi Power Company		X
Southern Power Company	X	
Southern Company Gas	X	

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No x (Response applicable to all registrants.)

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Registrant	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer	Smaller Reporting Company
The Southern Company	X			
Alabama Power Company			X	
Georgia Power Company			X	
Gulf Power Company			X	
Mississippi Power Company			X	
Southern Power Company			X	
Southern Company Gas			X	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x (Response applicable to all registrants.)

Aggregate market value of The Southern Company's common stock held by non-affiliates of The Southern Company at June 30, 2016: $51.1 billion. All of the common stock of the other registrants is held by The Southern Company. A description of each registrant's common stock follows:

Registrant	Description of Common Stock	Shares Outstanding at January 31, 2017
The Southern Company	Par Value $5 Per Share	991,051,161
Alabama Power Company	Par Value $40 Per Share	30,537,500
Georgia Power Company	Without Par Value	9,261,500
Gulf Power Company	Without Par Value	7,392,717
Mississippi Power Company	Without Par Value	1,121,000
Southern Power Company	Par Value $0.01 Per Share	1,000
Southern Company Gas	Par Value $0.01 Per Share	100

Documents incorporated by reference: specified portions of The Southern Company's Definitive Proxy Statement on Schedule 14A relating to the 2017 Annual Meeting of Stockholders are incorporated by reference into PART III. In addition, specified portions of the Definitive Information Statements on Schedule 14C of Alabama Power Company, Georgia Power Company, and Mississippi Power Company relating to each of their respective 2017 Annual Meetings of Shareholders are incorporated by reference into PART III.

Each of Southern Power Company and Southern Company Gas meets the conditions set forth in General Instructions I(1)(a) and (b) of Form 10-K and is therefore filing this Form 10-K with the reduced disclosure format specified in General Instructions I(2)(b), (c), and (d) of Form 10-K.

This combined Form 10-K is separately filed by The Southern Company, Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, Southern Power Company, and Southern Company Gas. Information contained herein relating to any individual company is filed by such company on its own behalf. Each company makes no representation as to information relating to the other companies.

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DEFINITIONS

When used in Items 1 through 5 and Items 9A through 15, the following terms will have the meanings indicated.

Term	Meaning
Alabama Power	Alabama Power Company
Bcf	Billion cubic feet
CCR	Coal combustion residuals
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
Contractor	Westinghouse and its affiliate, WECTEC Global Project Services Inc. (formerly known as CB&I Stone & Webster, Inc.), formerly a subsidiary of The Shaw Group Inc. and Chicago Bridge & Iron Company N.V.
Dalton	City of Dalton, Georgia, acting by and through its Board of Water, Light, and Sinking Fund Commissioners
DOE	U.S. Department of Energy
Duke Energy Florida	Duke Energy Florida, LLC
EMC	Electric membership corporation
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FMPA	Florida Municipal Power Agency
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
IBEW	International Brotherhood of Electrical Workers
IGCC	Integrated coal gasification combined cycle
IIC	Intercompany Interchange Contract
Internal Revenue Code	Internal Revenue Code of 1986, as amended
IPP	Independent Power Producer
IRP	Integrated Resource Plan
Kemper IGCC	IGCC facility under construction by Mississippi Power in Kemper County, Mississippi
KUA	Kissimmee Utility Authority
KW	Kilowatt
KWH	Kilowatt-hour
MEAG Power	Municipal Electric Authority of Georgia
Merger	The merger, effective July 1, 2016, of a wholly-owned, direct subsidiary of Southern Company with and into Southern Company Gas, with Southern Company Gas continuing as the surviving corporation
Mississippi Power	Mississippi Power Company
MW	Megawatt
natural gas distribution utilities	Southern Company Gas' seven natural gas distribution utilities (Nicor Gas, Atlanta Gas Light Company, Virginia Natural Gas, Inc., Elizabethtown Gas, Florida City Gas, Chattanooga Gas Company, and Elkton Gas)
Nicor Gas	Northern Illinois Gas Company, a wholly-owned subsidiary of Southern Company Gas
NRC	U.S. Nuclear Regulatory Commission
NYSE	New York Stock Exchange
OPC	Oglethorpe Power Corporation
OUC	Orlando Utilities Commission
PATH Act	Protecting Americans from Tax Hikes Act
	Two new nuclear generating units under construction at Georgia Power's Plant Vogtle

Plant Vogtle Units
3 and 4

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DEFINITIONS
(continued)

Term	Meaning
power pool	The operating arrangement whereby the integrated generating resources of the traditional electric operating companies and Southern Power (excluding subsidiaries) are subject to joint commitment and dispatch in order to serve their combined load obligations
PowerSecure	PowerSecure Inc.
PowerSouth	PowerSouth Energy Cooperative
PPA	Power purchase agreements and contracts for differences that provide the owner of a renewable facility a certain fixed price for the electricity sold to the grid
PSC	Public Service Commission
registrants	Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and Southern Company Gas
RUS	Rural Utilities Service
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	Securities and Exchange Commission
SEGCO	Southern Electric Generating Company
SEPA	Southeastern Power Administration
SERC	Southeastern Electric Reliability Council
SMEPA	South Mississippi Electric Power Association (now known as Cooperative Energy)
Southern Company	The Southern Company
Southern Company Gas	Southern Company Gas (formerly known as AGL Resources Inc.) and its subsidiaries
Southern Company Gas Capital	Southern Company Gas Capital Corporation (formerly known as AGL Capital Corporation), a 100%-owned subsidiary of Southern Company Gas
Southern Company system	Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), SEGCO, Southern Nuclear, SCS, Southern LINC, PowerSecure (as of May 9, 2016), and other subsidiaries
Southern Holdings	Southern Company Holdings, Inc.
Southern LINC	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
traditional electric operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power
Vogtle Owners	Georgia Power, OPC, MEAG Power, and Dalton
Westinghouse	Westinghouse Electric Company LLC

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CAUTIONARY STATEMENT REGARDING
FORWARD-LOOKING INFORMATION

This Annual Report on Form 10-K contains forward-looking statements. Forward-looking statements include, among other things, statements concerning regulated rates, the strategic goals for the wholesale business, customer and sales growth, economic conditions, 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 plans, postretirement benefit plans, and nuclear decommissioning trust fund contributions, financing activities, completion dates of construction projects, filings with state and federal regulatory authorities, impact of the PATH Act, federal income tax benefits, 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 environmental laws regulating emissions, discharges, and disposal to air, water, and land, and also changes in tax and other laws and regulations to which Southern Company and its subsidiaries are subject, including potential tax reform legislation, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries;
- the effects, extent, and timing of the entry of additional competition in the markets in which Southern Company's subsidiaries operate;
- variations in demand for electricity and natural gas, 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 natural gas and other fuels;
- limits on pipeline capacity;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development, construction, and operation of facilities, which include the development and construction of generating facilities with designs that have not been finalized or previously constructed, including changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, sustaining nitrogen supply, contractor or supplier delay, non-performance under construction, operating, or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by any PSC);
- the ability to construct facilities in accordance with the requirements of permits and licenses, to satisfy any environmental performance standards and the requirements of tax credits and other incentives, and to integrate facilities into the Southern Company system upon completion of construction;
- investment performance of the Southern Company system's employee and retiree benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- ongoing renewable energy partnerships and development agreements;
- 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;
- legal proceedings and regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals and NRC actions;

- actions related to cost recovery for the Kemper IGCC, including the ultimate impact of the 2015 decision of the Mississippi Supreme Court, the Mississippi PSC's December 2015 rate order, and related legal or regulatory proceedings, Mississippi

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PSC review of the prudence of Kemper IGCC costs and approval of further permanent rate recovery plans, actions relating to proposed securitization, satisfaction of requirements to utilize grants, and the ultimate impact of the termination of the proposed sale of an interest in the Kemper IGCC to SMEPA;

- the ability to successfully operate the electric utilities' generating, transmission, and distribution facilities and Southern Company Gas' natural gas distribution and storage facilities and the successful performance of necessary corporate functions;
- the inherent risks involved in operating and constructing nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, and financial risks;
- the inherent risks involved in transporting and storing natural gas;
- the performance of projects undertaken by the non-utility businesses and the success of efforts to invest in and develop new opportunities;
- 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 Southern Company or its subsidiaries;
- the possibility that the anticipated benefits from the Merger cannot be fully realized or may take longer to realize than expected, the possibility that costs related to the integration of Southern Company and Southern Company Gas will be greater than expected, the ability to retain and hire key personnel and maintain relationships with customers, suppliers, or other business partners, and the diversion of management time on integration-related issues;
- the ability of counterparties of Southern Company and its subsidiaries 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 Southern Company system'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 Southern Company's and any of its subsidiaries' 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 foreign currency exchange rates, counterparty performance, and the economy in general, as well as potential impacts on the benefits of the DOE loan guarantees;
- the ability of Southern Company's electric utilities 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 Southern Company system's business resulting from incidents affecting the U.S. electric grid, natural gas pipeline infrastructure, or operation of generating or storage resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports filed by the registrants from time to time with the SEC.

The registrants expressly disclaim any obligation to update any forward-looking statements.

PART I

Item 1. BUSINESS

Southern Company was incorporated under the laws of Delaware on November 9, 1945. Southern Company is registered and qualified to do business under the laws of Georgia and is qualified to do business as a foreign corporation under the laws of Alabama. Southern Company owns all of the outstanding common stock of Alabama Power, Georgia Power, Gulf Power, and Mississippi Power, each of which is an operating public utility company. The traditional electric operating companies supply electric service in the states of Alabama, Georgia, Florida, and Mississippi. More particular information relating to each of the traditional electric operating companies is as follows:

Alabama Power is a corporation organized under the laws of the State of Alabama on November 10, 1927, by the consolidation of a predecessor Alabama Power Company, Gulf Electric Company, and Houston Power Company. The predecessor Alabama Power Company had been in continuous existence since its incorporation in 1906.

Georgia Power was incorporated under the laws of the State of Georgia on June 26, 1930 and was admitted to do business in Alabama on September 15, 1948 and in Florida on October 13, 1997.

Gulf Power is a Florida corporation that has had a continuous existence since it was originally organized under the laws of the State of Maine on November 2, 1925. Gulf Power was admitted to do business in Florida on January 15, 1926, in Mississippi on October 25, 1976, and in Georgia on November 20, 1984. Gulf Power became a Florida corporation after being domesticated under the laws of the State of Florida on November 2, 2005.

Mississippi Power was incorporated under the laws of the State of Mississippi on July 12, 1972, was admitted to do business in Alabama on November 28, 1972, and effective December 21, 1972, by the merger into it of the predecessor Mississippi Power Company, succeeded to the business and properties of the latter company. The predecessor Mississippi Power Company was incorporated under the laws of the State of Maine on November 24, 1924 and was admitted to do business in Mississippi on December 23, 1924 and in Alabama on December 7, 1962.

In addition, Southern Company owns all of the common stock of Southern Power Company, which is also an operating public utility company. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. Southern Power Company is a corporation organized under the laws of Delaware on January 8, 2001. The term "Southern Power" when used herein refers to Southern Power Company and its subsidiaries while the term "Southern Power Company" when used herein refers only to the parent company.

On July 1, 2016, Southern Company completed the Merger for a total purchase price of approximately $8.0 billion and Southern Company Gas became a wholly-owned, direct subsidiary of Southern Company. Southern Company Gas is an energy services holding company whose primary business is the distribution of natural gas in seven states - Illinois, Georgia, Virginia, New Jersey, Florida, Tennessee, and Maryland - through the natural gas distribution utilities. Southern Company Gas is also involved in several other businesses that are complementary to the distribution of natural gas. Southern Company Gas was incorporated under the laws of the State of Georgia on November 27, 1995 for the primary purpose of becoming the holding company for Atlanta Gas Light Company, which was founded in 1856.

Southern Company also owns all of the outstanding common stock or membership interests of SCS, Southern LINC, Southern Holdings, Southern Nuclear, PowerSecure, and other direct and indirect subsidiaries. SCS, the system service company, has contracted with Southern Company, each traditional electric operating company, Southern Power, Southern Company Gas, Southern Nuclear, SEGCO, and other subsidiaries to furnish, at direct or allocated cost and upon request, the following services: 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 communication, and other services with respect to business and operations, construction management, and power pool transactions. Southern LINC 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 and is currently developing Plant Vogtle Units 3 and 4, which are co-owned by Georgia Power. PowerSecure is a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure.

Alabama Power and Georgia Power each own 50% of the outstanding common stock of SEGCO. SEGCO is an operating public utility company that owns electric generating units with an aggregate capacity of 1,020 MWs at Plant Gaston on the Coosa River near Wilsonville, Alabama. Alabama Power and Georgia Power are each entitled to one-half of SEGCO's capacity and energy. Alabama Power acts as SEGCO's agent in the operation of SEGCO's units and furnishes fuel to SEGCO for its units. SEGCO also owns one 230,000 volt transmission line extending from Plant Gaston to the Georgia state line at which point connection is made with the Georgia Power transmission line system. SEGCO added natural gas as a fuel source for 1,000 MWs of its generating capacity in 2015. In April 2016, natural gas became the primary fuel source. Alabama Power, 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 an associated gas pipeline. Alabama Power owns 14% of the pipeline with the remaining 86% owned by SEGCO.

Southern Company's segment information is included in Note 13 to the financial statements of Southern Company in Item 8 herein. Southern Company Gas' segment information is included in Note 12 to the financial statements of Southern Company Gas in Item 8 herein.

The registrants' Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and all amendments to those reports are made available on Southern Company's website, free of charge, as soon as reasonably practicable after such material is electronically filed with or furnished to the SEC. Southern Company's internet address is www.southerncompany.com.

The Southern Company System

Traditional Electric Operating Companies

The traditional electric operating companies are vertically integrated utilities that own generation, transmission, and distribution facilities. See PROPERTIES in Item 2 herein for additional information on the traditional electric operating companies' generating facilities. Each company's transmission facilities are connected to the respective company's own generating plants and other sources of power (including certain generating plants owned by Southern Power) and are interconnected with the transmission facilities of the other traditional electric operating companies and SEGCO. For information on the State of Georgia's integrated transmission system, see "Territory Served by the Southern Company System – Traditional Electric Operating Companies and Southern Power" herein.

Agreements in effect with principal neighboring utility systems provide for capacity and energy transactions that may be entered into from time to time for reasons related to reliability or economics. Additionally, the traditional electric operating companies have entered into voluntary reliability agreements with the subsidiaries of Entergy Corporation, Florida Electric Power Coordinating Group, and Tennessee Valley Authority and with Duke Energy Progress, LLC, Duke Energy Carolinas, LLC, South Carolina Electric & Gas Company, and Virginia Electric and Power Company, each of which provides for the establishment and periodic review of principles and procedures for planning and operation of generation and transmission facilities, maintenance schedules, load retention programs, emergency operations, and other matters affecting the reliability of bulk power supply. The traditional electric operating companies have joined with other utilities in the Southeast (including some of those referred to above) to form the SERC to augment further the reliability and adequacy of bulk power supply. Through the SERC, the traditional electric operating companies are represented on the National Electric Reliability Council.

The utility assets of the traditional electric operating companies and certain utility assets of Southern Power Company are operated as a single integrated electric system, or power pool, pursuant to the IIC. Activities under the IIC are administered by SCS, which acts as agent for the traditional electric operating companies and Southern Power Company. The fundamental purpose of the power pool is to provide for the coordinated operation of the electric facilities in an effort to achieve the maximum possible economies consistent with the highest practicable reliability of service. Subject to service requirements and other operating limitations, system resources are committed and controlled through the application of centralized economic dispatch. Under the IIC, each traditional electric operating company and Southern Power Company retains its lowest cost energy resources for the benefit of its own customers and delivers any excess energy to the power pool for use in serving customers of other traditional electric operating companies or Southern Power Company or for sale by the power pool to third parties. The IIC provides for the recovery of specified costs associated with the affiliated operations thereunder, as well as the proportionate sharing of costs and revenues resulting from power pool transactions with third parties.

Southern Power and Southern LINC have secured from the traditional electric operating companies certain services which are furnished at cost in compliance with FERC regulations.

Alabama Power and Georgia Power each have a contract with Southern Nuclear to operate the Southern Company system's existing nuclear plants, Plants Farley, Hatch, and Vogtle. In addition, Georgia Power has a contract with Southern Nuclear to develop, license, construct, and operate Plant Vogtle Units 3 and 4. See "Regulation – Nuclear

Regulation" herein for additional information.

Southern Power

Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates (under authority from the FERC) in the wholesale market. Southern Power continually seeks opportunities to execute its strategy to create value through various transactions including acquisitions and sales of assets, construction of new generating facilities, and entry into PPAs primarily with investor-owned utilities, IPPs, municipalities, electric cooperatives, and other load serving entities. Southern Power's business activities are not subject to traditional state regulation like the traditional electric operating companies, but the majority of its business activities are subject to regulation by the FERC. Southern Power has attempted to insulate itself from significant fuel supply, fuel transportation, and electric transmission risks by generally making such risks the responsibility of the counterparties to its PPAs. However, Southern Power's future earnings will depend on the parameters of the wholesale market and the efficient operation of its wholesale generating assets, as well as Southern Power's ability to execute its growth strategy and to construct generating facilities. For additional information on Southern Power's business activities, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Business Activities" of Southern Power in Item 7 herein.

Southern Power Company directly owns and manages generation assets primarily in the Southeast, which are included in the power pool, and has other wholly-owned subsidiaries, two of which are Southern Renewable Energy, Inc. (SRE) and Southern Renewable Partnerships, LLC (SRP), which were created to own and operate renewable generation facilities either wholly or in partnership with various third parties, including Turner Renewable Energy, LLC (TRE), First Solar Inc., Recurrent Energy, a subsidiary of Canadian Solar Inc., or SunPower Corp. The generation assets of these subsidiaries are not included in the power pool. In addition, Southern Power Company has other subsidiaries either with natural gas and biomass generating facilities or pursuing additional natural gas generation and other development opportunities.

Some of SRP's partnerships allow for the sharing of cash distributions and tax benefits at differing percentages. SRP is entitled to 51% of all cash distributions from eight of the partnership entities and the respective partner who holds the class B membership interests is entitled to 49% of all cash distributions. For the Desert Stateline partnership, SRP is entitled to 66% of all cash distributions and the class B member is entitled to 34% of all cash distributions. In addition, Southern Power is entitled to substantially all of the federal tax benefits with respect to these nine partnership entities.

During 2016, Southern Power acquired or commenced construction of approximately 2,134 MWs of additional solar, wind, and natural gas facilities and completed construction of approximately 1,060 MWs of solar facilities. The aggregate purchase price for projects acquired by Southern Power's subsidiaries during 2016 and 2015 was $2.3 billion and $1.4 billion, respectively. During 2016, Southern Power's subsidiaries completed construction of and placed in service projects with a total construction cost of approximately $3.2 billion.

In December 2016, as part of Southern Power's renewable development strategy, SRP entered into a joint development agreement with Renewable Energy Systems Americas, Inc. (RES) to develop and construct approximately 3,000 MWs across 10 wind projects expected to be placed in service between 2018 and 2020. Also in December 2016, Southern Power signed agreements and made payments to purchase wind turbine equipment from Siemens Wind Projects, Inc. and Vestas-American Wind Technology, Inc. to be used for construction of the facilities. Once these wind projects reach commercial operation, they are expected to qualify for 100% production tax credits (PTCs).

The ultimate outcome of these matters cannot be determined at this time. For additional information on SRE and SRP, see MANAGEMENT'S DISCUSSION AND ANALYSIS – "Acquisitions" and "Construction Projects" of Southern Power in Item 7 herein.

See Item 2 – Properties, Note 2 to the financial statements of Southern Power in Item 8 herein, and Note 12 to the financial statements of Southern Company under "Southern Power" in Item 8 herein for additional information regarding Southern Power's acquisitions, construction, and development projects.

As of December 31, 2016, Southern Power owned generating units totaling 11,768 MWs of nameplate capacity in commercial operation, after taking into consideration its equity ownership percentage of the solar and wind facilities. Southern Power calculates an investment coverage ratio for its generating assets based on the ratio of investment under contract to total investment using the respective generation facilities' net book value (or expected in-service value for facilities under construction or being acquired) as the investment amount. With the inclusion of the PPAs and investment associated with the solar and natural-gas fired facilities currently under construction and Bethel Wind, which was acquired subsequent to December 31, 2016, as well as other capacity and energy contracts, Southern Power has an average investment coverage ratio of 91% through 2021 and 90% through 2026, with an average remaining contract duration of approximately 16 years.

Southern Power's natural gas and biomass sales are primarily through long-term PPAs that consist of two types of agreements. The first type, referred to as a unit or block sale, is a customer purchase from a dedicated plant unit where all or a portion of the generation from that unit is reserved for that customer. Southern Power typically has the ability to serve the unit or block sale customer from an alternate resource. The second type, referred to as requirements service, provides that Southern Power serve the customer's capacity and energy requirements from a combination of the customer's own generating units and from Southern Power resources not dedicated to serve unit or block sales. Southern Power has rights to purchase power provided by the requirements customers' resources when economically viable.

Southern Power's electricity sales from solar and wind generating facilities are predominantly through long-term PPAs; however, these solar and wind PPAs do not have a capacity charge and customers either purchase the energy output of a dedicated renewable facility through an energy charge or provide Southern Power a certain fixed price for the electricity sold to the grid.

The following tables set forth Southern Power's PPAs as of December 31, 2016:

Block Sales PPAs

Facility/Source	Counterparty	MWs	Contract Term
Addison Unit 1	MEAG Power	152	through April 2029
Addison Units 2 and 4	Georgia Power	293	through May 2030
Addison Unit 3	Georgia Energy Cooperative	151	through May 2030
Cleveland County Unit 1	North Carolina Electric Membership Corporation (NCEMC)	45-180	through Dec. 2036
Cleveland County Unit 2	NCEMC	180	through Dec. 2036
Cleveland County Unit 3	North Carolina Municipal Power Agency 1	183	through Dec. 2031
Dahlberg Units 1, 3, and 5	Cobb EMC	224	through Dec. 2026
Dahlberg Units 2, 6, 8, and 10	Georgia Power	298	through May 2025
Dahlberg Unit 4	Georgia Power	73	through May 2030
Franklin Unit 1	Duke Energy Florida	434	through May 2021
Franklin Unit 2	Morgan Stanley Capital Group	250	through Dec. 2025
Franklin Unit 2	Jackson EMC	60-65	through Dec. 2035
Franklin Unit 2	GreyStone Power Corporation	35-40	through Dec. 2035
Franklin Unit 2	Cobb EMC	100	through Dec. 2026
Franklin Unit 3	Morgan Stanley Capital Group	200	through Dec. 2027
Harris Unit 1	Georgia Power	628	through May 2030
Harris Unit 2	Georgia Power	649	through May 2019
Harris Unit 2	Alabama Municipal Electric Authority(1)	25	Jan. 2020 – Dec. 2025
Mankato	Northern States Power Company	375	through June 2026
Mankato	Northern States Power Company	345	June 2019 – May 2039(2)
Nacogdoches	City of Austin, Texas	100	through May 2032
NCEMC PPA(3)	EnergyUnited	100	through Dec. 2021
Oleander Units 2, 3, and 4	Seminole Electric Cooperative	465	through May 2021
Oleander Unit 5	FMPA	157	through Dec. 2027
Rowan CT Unit 1	North Carolina Municipal Power Agency 1	150	through Dec. 2030
Rowan CT Units 2 and 3	EnergyUnited	100-175	Jan. 2022 – Dec. 2025
Rowan CT Unit 3	EnergyUnited	113	through Dec. 2023
Rowan CC Unit 4	EnergyUnited	9-328	through Dec. 2025
Rowan CC Unit 4	Duke Energy Progress, LLC	150	through Dec. 2019
Rowan CC Unit 4(4)	Century Aluminum	154	through Dec. 2017
Stanton Unit A	OUC	341	through Sept. 2033
Stanton Unit A	FMPA	85	through Sept. 2033
Wansley Unit 6	Georgia Power	570	through May 2017

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(1) Alabama Municipal Electric Authority will also be served by Plant Franklin Unit 1 from January 2018 through December 2019.
(2) Subject to commercial operation of the expansion project.
(3) Represents sale of power purchased from NCEMC under a PPA.
(4) Century Aluminum PPA is partially served by Plant Franklin Unit 3.

Requirements Services PPAs

Counterparty	MWs		Contract Term
Nine Georgia EMCs	281-370	(1)	through Dec. 2024
Sawnee EMC	267-609	(1)	through Dec. 2027
Cobb EMC	0-160	(1)	through Dec. 2026
Flint EMC	132-316	(1)	through Dec. 2024
City of Dalton, Georgia	60		through Dec. 2017
EnergyUnited	55-152	(1)	through Dec. 2025
City of Blountstown, Florida	10		through April 2022

(1) Represents a range of forecasted incremental capacity needs over the contract term.

Solar/Wind PPAs

Facility	Counterparty	MWs(1)	Contract Term
Solar			
Adobe(2)	Southern California Edison Company	20	through May 2034
Apex(2)	Nevada Power Company	20	through Dec. 2037
Boulder 1(3)	Nevada Power Company	100	through Dec. 2036
Butler	Georgia Power	100	through Dec. 2046
Butler Solar Farm	Georgia Power	20	through Feb. 2036
Calipatria(2)	San Diego Gas & Electric Company	20	through Feb. 2036
Campo Verde(2)	San Diego Gas & Electric Company	139	through Sept. 2033
Cimarron(2)	Tri-State Generation and Transmission Association, Inc.	30	through Nov. 2035
Decatur County	Georgia Power	19	through Dec. 2035
Decatur Parkway	Georgia Power	80	through Dec. 2040
Desert Stateline(4)	Southern California Edison Company	300	through Aug. 2036
East Pecos	Austin Energy	119	March 2017 – Feb. 2032 (6)
Garland A(3)	Southern California Edison Company	20	through Sept. 2036
Garland(3)	Southern California Edison Company	180	through Oct. 2031
Granville(2)	Duke Energy Progress, LLC	2	through Nov. 2032
Henrietta(3)	Pacific Gas & Electric Company	100	through Sept. 2036
Imperial Valley(3)	San Diego Gas & Electric Company	150	through Nov. 2039
Lamesa	City of Garland, Texas	102	April 2017 – March 2032 (6)
Lost Hills Blackwell(3)	City of Roseville & Pacific Gas & Electric Company	32	through Dec. 2043
Macho Springs(2)	El Paso Energy	50	through May 2034
Morelos(2)	Pacific Gas & Electric Company	15	through Feb. 2036
North Star(3)	Pacific Gas & Electric Company	60	through June 2035
Pawpaw	Georgia Power	30	through March 2046
Roserock(3)	Austin Energy	157	through Nov. 2036
Rutherford(2)	Duke Energy Carolinas, LLC	75	through Dec. 2031

Facility	Counterparty	MWs(1)	Contract Term
Sandhills	Cobb EMC	111	through Oct. 2041
Sandhills	Flint EMC	15	through Oct. 2041
Sandhills	Sawnee EMC	15	through Oct. 2041
Sandhills	Middle Georgia and Irwin EMC	2	through Oct. 2041
Spectrum(2)	Nevada Power Company	30	through Dec. 2038
Tranquillity(3)	Shell Energy North America (US), LP	204	through Nov. 2019
Tranquillity(3)	Southern California Edison Company	204	Dec. 2019 – Nov. 2034
Wind			
Grant Plains	Oklahoma Municipal Power Authority	41	Jan. 2020 – Dec. 2039
Grant Plains	Steelcase Inc.	25	through Dec. 2028
Grant Plains	Allianz Risk Transfer (Bermuda) Ltd.	81-122	April 2017 – March 2027
Grant Wind	East Texas Electric Cooperative	50	through March 2036
Grant Wind	Northeast Texas Electric Cooperative	50	through March 2036
Grant Wind	Western Farmers Electric Cooperative	50	through March 2036
Kay Wind	Westar Energy Inc.	199	through Sept. 2036
Kay Wind	Grand River Dam Authority	100	through Dec. 2035
Passadumkeag	Western Massachusetts Electric Company	40	through June 2031
Salt Fork Wind	City of Garland, Texas	150	through Nov. 2030
Salt Fork Wind	Salesforce.com, Inc.	24	through Nov. 2028
Tyler Bluff Wind	The Proctor & Gamble Company	96	through Dec. 2028
Wake Wind(5)	Equinix Enterprises, Inc.	100	through Oct. 2028
Wake Wind(5)	Owens Corning	125	through Oct. 2028

(1) MWs shown are for 100% of the PPA, which is based on demonstrated capacity of the facility.
(2) Southern Power's subsidiary's equity interest in these facilities is 90%.
(3) Southern Power's subsidiary's equity interest in these facilities is 51%.
(4) Southern Power's subsidiary's equity interest in this facility is 66%.
(5) Southern Power's subsidiary's equity interest in this facility is 90.1%.
(6) Subject to commercial operation.

Purchased Power

Facility/Source	Counterparty	MWs	Contract Term
NCEMC	NCEMC	100	through Dec. 2021

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" and "Acquisitions" of Southern Power in Item 7 herein and Note 2 to the financial statements of Southern Power in Item 8 herein for additional information.

For the year ended December 31, 2016, Southern Power's revenues were derived approximately 16.5% from Georgia Power. Southern Power actively pursues replacement PPAs prior to the expiration of its current PPAs and anticipates that the revenues attributable to one customer may be replaced by revenues from a new customer; however, the expiration of any of Southern Power's current PPAs without the successful remarketing of a replacement PPA could have a material negative impact on Southern Power's earnings but is not expected to have a material impact on Southern Company's earnings.

Southern Company Gas

Southern Company Gas is an energy services holding company whose primary business is the distribution of natural gas through the natural gas distribution utilities. Southern Company Gas is also involved in several other businesses that are complementary to the distribution of natural gas, including gas marketing services, wholesale gas services, and gas midstream operations.

Gas distribution operations, the largest segment of Southern Company Gas' business, operates, constructs, and maintains 81,600 miles of natural gas pipelines and 14 storage facilities, with total capacity of 158 Bcf, to provide natural gas to residential, commercial, and industrial customers. Gas distribution operations serves approximately 4.6 million customers across seven states and has rates of return that are regulated by each individual state in return for exclusive franchises.

Gas marketing services is comprised of Southstar Energy Services, LLC (SouthStar) and Nicor Energy Services Company (doing business as Pivotal Home Solutions) and provides natural gas commodity and related services to customers in competitive markets or markets that provide for customer choice. SouthStar, serving approximately 643,000 natural gas commodity customers, markets gas to residential, commercial, and industrial customers and offers energy-related products that provide natural gas price stability and utility bill management. Pivotal Home Solutions, serving approximately 1.2 million service contracts, provides a suite of home protection products and services that offers homeowners predictability regarding their energy service delivery, systems, and appliances.

Wholesale gas services consists of Sequent Energy Management, L.P. and engages in natural gas storage and gas pipeline arbitrage and provides natural gas asset management and related logistical services to most of the natural gas distribution utilities as well as non-affiliate companies.

Gas midstream operations includes joint ventures in pipeline investments (including a 50% ownership interest in SNG and two significant pipeline construction projects) as well as a 50% joint ownership in a significant pipeline project and wholly-owned natural gas storage facilities that enable the provision of diverse sources of natural gas supplies to the customers of Southern Company Gas. On September 1, 2016, Southern Company Gas paid $1.4 billion to acquire a 50% equity interest in SNG, which is the owner of a 7,000 mile pipeline connecting natural gas supply basins in Texas, Louisiana, Mississippi, and Alabama to markets in Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina, and Tennessee.

For additional information on Southern Company Gas' business activities, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Business Activities" and – FUTURE EARNINGS POTENTIAL of Southern Company Gas in Item 7 herein.

Other Businesses

PowerSecure provides products and services in the areas of distributed generation, energy efficiency, and utility infrastructure. Southern Company acquired PowerSecure on May 9, 2016 for an aggregate purchase price of $429 million.

Southern Holdings is an intermediate holding subsidiary, primarily for Southern Company's investments in leveraged leases and also for energy services.

Southern LINC provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public. Southern LINC delivers multiple wireless communication options including push to talk, cellular service, text messaging, wireless internet access, and wireless data. Its system covers approximately 127,000 square miles in the Southeast. Southern LINC also provides fiber cable services within the Southeast through its subsidiary, Southern Telecom, Inc.

These efforts to invest in and develop new business opportunities offer potential returns exceeding those of rate-regulated operations. However, these activities also involve a higher degree of risk.

Construction Programs

The subsidiary companies of Southern Company are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. For estimated construction and environmental expenditures for the periods 2017 through 2021, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Southern Company, each traditional electric operating company, Southern Power, and Southern Company Gas in Item 7 herein.

The Southern Company system's construction program consists of capital investment and capital expenditures to comply with environmental statutes and regulations. The traditional electric operating companies also anticipate costs associated with closure and groundwater monitoring under the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), which are reflected in the Southern Company system's asset retirement obligation liabilities. In 2017, the construction program is expected to be apportioned approximately as follows:

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	Southern Company system[(a)(b)] (in billions)	Alabama Power	Georgia Power	Gulf Power	Mississippi Power
New Generation	$1.0	$ —	$ 0.7	$ —	$ 0.3
Environmental Compliance[(c)]	0.9	0.5	0.4	—	—
Generation Maintenance	0.9	0.4	0.3	0.1	0.1
Transmission	0.8	0.3	0.4	—	—
Distribution	1.0	0.4	0.5	0.1	0.1
Nuclear Fuel	0.2	0.1	0.1	—	—
General Plant	0.4	0.1	0.2	—	0.1
	5.3	1.9	2.6	0.2	0.5
Southern Power[(d)]	1.6				
Southern Company Gas[(e)]	1.7				
Other subsidiaries	0.5				
Total[(a)]	$9.1	$ 1.9	$ 2.6	$ 0.2	$ 0.5

(a) Totals do not add due to rounding.

(b) Includes the traditional electric operating companies, Southern Power, and Southern Company Gas, as well as the other subsidiaries. See "Other Businesses" herein for additional information.

(c) Reflects cost estimates for environmental regulations. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's final rules and guidelines or future state plans that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units or costs associated with closure and groundwater monitoring under the CCR Rule. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" and FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Southern Company and each traditional electric operating company in Item 7 herein for additional information.

(d) Includes approximately $0.8 billion for potential acquisitions and/or construction of new generating facilities.

(e) Includes costs for ongoing capital projects associated with infrastructure improvement programs in six different states that have been previously approved by their applicable state regulatory agencies. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Infrastructure Replacement Programs and Capital Projects" of Southern Company Gas in Item 7 herein for additional information.

The construction programs are 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 electric generating plants, including unit retirements and replacements and adding or changing fuel sources at existing electric generating units, to meet regulatory requirements; changes in FERC rules and regulations; state regulatory agency approvals; changes in the expected environmental compliance program; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. Additionally, planned expenditures for plant acquisitions may vary due to market opportunities and Southern Power's ability to execute its growth strategy.

In addition, the construction program includes the development and construction of new electric generating facilities with designs that have not been finalized or previously constructed, including first-of-a-kind technology, which may result in revised estimates during construction. See Note 3 to the financial statements of Southern Company and Georgia Power under "Regulatory Matters – Georgia Power – Nuclear Construction" and "Retail Regulatory Matters – Nuclear Construction," respectively, in Item 8 herein for additional information regarding Georgia Power's construction of Plant Vogtle Units 3 and 4. Also see Note 3 to the financial statements of Southern Company and Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 herein for additional information regarding Mississippi Power's construction of the Kemper IGCC.

Also see "Regulation – Environmental Statutes and Regulations" herein for additional information with respect to certain existing and proposed environmental requirements and PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information concerning Alabama Power's, Georgia Power's, and Southern Power's joint ownership of certain generating units and related facilities with certain non-affiliated utilities.

Financing Programs

See each of the registrant's MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY in Item 7 herein and Note 6 to the financial statements of each registrant in Item 8 herein for information concerning financing programs.

Fuel Supply

Electric

The traditional electric operating companies' and SEGCO's supply of electricity is primarily fueled by natural gas and coal. Southern Power's supply of electricity is primarily fueled by natural gas. See MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATION – "Electricity Business – Fuel and Purchased Power Expenses" of Southern Company and MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATION – "Fuel and Purchased Power Expenses" of each traditional electric operating company in Item 7 herein for information regarding the electricity generated and the average cost of fuel in cents per net KWH generated for the years 2014 through 2016.

The traditional electric operating companies have agreements in place from which they expect to receive substantially all of their coal burn requirements in 2017. These agreements have terms ranging between one and four years. In 2016, the weighted average sulfur content of all coal burned by the traditional electric operating companies was 0.98% sulfur. This sulfur level, along with banked and purchased sulfur dioxide allowances, allowed the traditional electric operating companies to remain within limits set by Phase I of the Cross-State Air Pollution Rule (CSAPR) under the Clean Air Act. In 2016, the Southern Company system did not purchase any sulfur dioxide allowances, annual nitrogen oxide emission allowances, or seasonal nitrogen oxide emission allowances from the market. As any additional environmental regulations are proposed that impact the utilization of coal, the traditional electric operating companies' fuel mix will be monitored to help ensure that the traditional electric operating companies remain in compliance with applicable laws and regulations. Additionally, Southern Company and the traditional electric operating companies will continue to evaluate the need to purchase additional emissions allowances, the timing of capital expenditures for emissions control equipment, and potential unit retirements and replacements. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company, each traditional electric operating company, and Southern Power in Item 7 herein for additional information on environmental matters.

SCS, acting on behalf of the traditional electric operating companies and Southern Power Company, has agreements in place for the natural gas burn requirements of the Southern Company system. For 2017, SCS has contracted for 477 Bcf of natural gas supply under agreements with remaining terms up to 15 years. In addition to natural gas supply, SCS has contracts in place for both firm natural gas transportation and storage. Management believes these contracts provide sufficient natural gas supplies, transportation, and storage to ensure normal operations of the Southern Company system's natural gas generating units.

Alabama Power and Georgia Power have multiple contracts covering their nuclear fuel needs for uranium, conversion services, enrichment services, and fuel fabrication. The uranium, conversion services, and fuel fabrication contracts are for terms of less than 10 years with varying expiration dates. The term lengths for the enrichment services contracts are for less than 15 years with varying expiration dates. Management believes suppliers have sufficient nuclear fuel production capability to permit the normal operation of the Southern Company system's nuclear generating units.

Changes in fuel prices to the traditional electric operating companies are generally reflected in fuel adjustment clauses contained in rate schedules. See "Rate Matters – Rate Structure and Cost Recovery Plans" herein for additional information. Southern Power's PPAs (excluding solar and wind) generally provide that the counterparty is responsible for substantially all of the cost of fuel.

Alabama Power and Georgia Power have contracts with the United States, acting through the DOE, that provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent fuel in 1998, as required by the contracts, and Alabama Power and Georgia Power have pursued and are pursuing legal remedies against the government for breach of contract. See Note 3 to the financial statements of Southern Company, Alabama Power, and Georgia Power under "Nuclear Fuel Disposal Costs" in Item 8 herein for additional information.

Natural Gas

Recent advances in natural gas drilling in shale producing regions of the U.S. have resulted in historically high supplies of natural gas and relatively low prices for natural gas. Procurement plans for natural gas supply and transportation to serve regulated utility customers are reviewed and approved by the state regulatory agencies in which Southern Company Gas operates. Southern Company Gas purchases natural gas supplies in the open market by contracting with producers and marketers and from its wholly-owned subsidiary, Sequent Energy Management, L.P., under asset management agreements in states where such agreements are approved by the applicable state regulatory agency. Southern Company Gas also contracts for transportation and storage services from interstate pipelines that are regulated by the FERC. When firm pipeline services are temporarily not needed, Southern Company Gas may release the services in the secondary market under FERC-approved capacity release provisions or utilize asset management arrangements, thereby reducing the net cost of natural gas charged to customers for most of the natural gas distribution utilities. Peak-use requirements are met through utilization of company-owned storage facilities, pipeline transportation capacity, purchased storage services, peaking facilities, and other supply sources, arranged by either transportation customers or Southern Company Gas.

Territory Served by the Southern Company System

Traditional Electric Operating Companies and Southern Power

The territory in which the traditional electric operating companies provide electric service comprises most of the states of Alabama and Georgia, together with the northwestern portion of Florida and southeastern Mississippi. In this territory there are non-affiliated electric distribution systems that obtain some or all of their power requirements either directly or indirectly from the traditional electric operating companies. As of December 31, 2016, the territory had an area of approximately 120,000 square miles and an estimated population of approximately 17 million. Southern Power sells electricity at market-based rates in the wholesale market, primarily to investor-owned utilities, IPPs, municipalities, electric cooperatives, and other load serving entities.

Alabama Power is engaged, within the State of Alabama, in the generation, transmission, distribution, and purchase of electricity and the sale of electric service, at retail in approximately 400 cities and towns (including Anniston, Birmingham, Gadsden, Mobile, Montgomery, and Tuscaloosa), as well as in rural areas, and at wholesale to 14 municipally-owned electric distribution systems, 11 of which are served indirectly through sales to AMEA, and two rural distributing cooperative associations. Alabama Power owns coal reserves near its Plant Gorgas and uses the output of coal from the reserves in its generating plants. Alabama Power also sells, and cooperates with dealers in promoting the sale of, electric appliances.

Georgia Power is engaged in the generation, transmission, distribution, and purchase of electricity and the sale of electric service within the State of Georgia, at retail in over 600 communities (including Athens, Atlanta, Augusta, Columbus, Macon, Rome, and Savannah), as well as in rural areas, and at wholesale currently to OPC, MEAG Power, Dalton, various EMCs, and non-affiliated utilities. Georgia Power also markets and sells outdoor lighting services.

Gulf Power is engaged, within the northwestern portion of Florida, in the generation, transmission, distribution, and purchase of electricity and the sale of electric service, at retail in 71 communities (including Pensacola, Panama City, and Fort Walton Beach), as well as in rural areas, and at wholesale to a non-affiliated utility.

Mississippi Power is engaged in the generation, transmission, distribution, and purchase of electricity and the sale of electric service within 23 counties in southeastern Mississippi, at retail in 123 communities (including Biloxi, Gulfport, Hattiesburg, Laurel, Meridian, and Pascagoula), as well as in rural areas, and at wholesale to one municipality, six rural electric distribution cooperative associations, and one generating and transmitting cooperative.

For information relating to KWH sales by customer classification for the traditional electric operating companies, see MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATIONS of each traditional electric operating company in Item 7 herein. Also, for information relating to the sources of revenues for Southern Company, each traditional electric operating company, and Southern Power, reference is made to Item 7 herein.

The RUS has authority to make loans to cooperative associations or corporations to enable them to provide electric service to customers in rural sections of the country. As of December 31, 2016, there were 71 electric cooperative organizations operating in the territory in which the traditional electric operating companies provide electric service at retail or wholesale.

One of these organizations, PowerSouth, is a generating and transmitting cooperative selling power to several distributing cooperatives, municipal systems, and other customers in south Alabama and northwest Florida. As of December 31, 2016, PowerSouth owned generating units with approximately 2,100 MWs of nameplate capacity, including an undivided 8.16% ownership interest in Alabama Power's Plant Miller Units 1 and 2. PowerSouth's facilities were financed with RUS loans secured by long-term contracts requiring distributing cooperatives to take their requirements from PowerSouth to the extent such energy is available. See PROPERTIES – "Jointly-Owned

Facilities" in Item 2 herein for details of Alabama Power's joint-ownership with PowerSouth of a portion of Plant Miller. Alabama Power has a 15-year system supply agreement with PowerSouth to provide 200 MWs of capacity service with an option to extend and renegotiate in the event Alabama Power builds new generation or contracts for new capacity.

Alabama Power and Gulf Power have entered into separate agreements with PowerSouth involving interconnection between their respective systems. The delivery of capacity and energy from PowerSouth to certain distributing cooperatives in the service territories of Alabama Power and Gulf Power is governed by the Southern Company/PowerSouth Network Transmission Service Agreement. The rates for this service to PowerSouth are on file with the FERC.

Four electric cooperative associations, financed by the RUS, operate within Gulf Power's service territory. These cooperatives purchase their full requirements from PowerSouth and SEPA (a federal power marketing agency). A non-affiliated utility also operates within Gulf Power's service territory and purchases its full requirements from Gulf Power.

Mississippi Power has an interchange agreement with SMEPA, a generating and transmitting cooperative, pursuant to which various services are provided.

As of December 31, 2016, there were approximately 65 municipally-owned electric distribution systems operating in the territory in which the traditional electric operating companies provide electric service at retail or wholesale.

As of December 31, 2016, 48 municipally-owned electric distribution systems and one county-owned system received their requirements through MEAG Power, which was established by a Georgia state statute in 1975. MEAG Power serves these requirements from self-owned generation facilities, some of which are jointly-owned with Georgia Power, and purchases from other resources. MEAG Power also has a pseudo scheduling and services agreement with Georgia Power. Dalton serves its requirements from self-owned generation facilities, some of which are jointly-owned with Georgia Power, and through purchases from Georgia Power and Southern Power through a service agreement. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information.

Georgia Power has entered into substantially similar agreements with Georgia Transmission Corporation, MEAG Power, and Dalton providing for the establishment of an integrated transmission system to carry the power and energy of all parties. The agreements require an investment by each party in the integrated transmission system in proportion to its respective share of the aggregate system load. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information.

Southern Power assumed or entered into PPAs with some of the traditional electric operating companies, investor-owned utilities, IPPs, municipalities, electric cooperatives, and other load serving entities. See "The Southern Company System – Southern Power" above and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" of Southern Power in Item 7 herein for additional information concerning Southern Power's PPAs.

SCS, acting on behalf of the traditional electric operating companies, also has a contract with SEPA providing for the use of the traditional electric operating companies' facilities at government expense to deliver to certain cooperatives and municipalities, entitled by federal statute to preference in the purchase of power from SEPA, quantities of power equivalent to the amounts of power allocated to them by SEPA from certain U.S. government hydroelectric projects.

Southern Company Gas

Southern Company Gas is engaged in the distribution of natural gas in seven states through the natural gas distribution utilities. The natural gas distribution utilities construct, manage, and maintain intrastate natural gas pipelines and distribution facilities and include:

Utility	State	Number of customers (in thousands)	Approximate miles of pipe
Nicor Gas	Illinois	2,220	34,300
Atlanta Gas Light Company	Georgia	1,603	33,100
Virginia Natural Gas, Inc.	Virginia	296	5,600
Elizabethtown Gas	New Jersey	287	3,200
Florida City Gas	Florida	108	3,700
Chattanooga Gas Company	Tennessee	65	1,600
Elkton Gas	Maryland	7	100
Total		4,586	81,600

For information relating to the sources of revenue for Southern Company Gas, see MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATIONS and – FUTURE EARNINGS POTENTIAL of Southern Company

Gas in Item 7 herein.

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Competition

Electric

The electric utility industry in the U.S. is continuing to evolve as a result of regulatory and competitive factors. Among the early primary agents of change was the Energy Policy Act of 1992, which allowed IPPs to access a utility's transmission network in order to sell electricity to other utilities.

The competition for retail energy sales among competing suppliers of energy is influenced by various factors, including price, availability, technological advancements, service, and reliability. These factors are, in turn, affected by, among other influences, regulatory, political, and environmental considerations, taxation, and supply.

The retail service rights of all electric suppliers in the State of Georgia are regulated by the Territorial Electric Service Act of 1973. Pursuant to the provisions of this Act, all areas within existing municipal limits were assigned to the primary electric supplier therein. Areas outside of such municipal limits were either to be assigned or to be declared open for customer choice of supplier by action of the Georgia PSC pursuant to standards set forth in this Act. Consistent with such standards, the Georgia PSC has assigned substantially all of the land area in the state to a supplier. Notwithstanding such assignments, this Act provides that any new customer locating outside of 1973 municipal limits and having a connected load of at least 900 KWs may exercise a one-time choice for the life of the premises to receive electric service from the supplier of its choice.

Pursuant to the 1956 Utility Act, the Mississippi PSC issued "Grandfather Certificates" of public convenience and necessity to Mississippi Power and to six distribution rural cooperatives operating in southeastern Mississippi, then served in whole or in part by Mississippi Power, authorizing them to distribute electricity in certain specified geographically described areas of the state. The six cooperatives serve approximately 325,000 retail customers in a certificated area of approximately 10,300 square miles. In areas included in a "Grandfather Certificate," the utility holding such certificate may, without further certification, extend its lines up to five miles; other extensions within that area by such utility, or by other utilities, may not be made except upon a showing of, and a grant of a certificate of, public convenience and necessity. Areas included in such a certificate that are subsequently annexed to municipalities may continue to be served by the holder of the certificate, irrespective of whether it has a franchise in the annexing municipality. On the other hand, the holder of the municipal franchise may not extend service into such newly annexed area without authorization by the Mississippi PSC.

Generally, the traditional electric operating companies have experienced, and expect to continue to experience, competition in their respective retail service territories in varying degrees from the development and deployment of alternative energy sources such as self-generation (as described below) and distributed generation technologies, as well as other factors.

Southern Power competes with investor-owned utilities, IPPs, and others for wholesale energy sales primarily in the Southeastern U.S. wholesale market. The needs of this market are driven by the demands of end users in the Southeast and the generation available. Southern Power's success in wholesale energy sales is influenced by various factors including reliability and availability of Southern Power's plants, availability of transmission to serve the demand, price, and Southern Power's ability to contain costs.

As of December 31, 2016, Alabama Power had cogeneration contracts in effect with nine industrial customers. Under the terms of these contracts, Alabama Power purchases excess energy generated by such companies. During 2016, Alabama Power purchased approximately 78 million KWHs from such companies at a cost of $2 million.

As of December 31, 2016, Georgia Power had contracts in effect with 29 small power producers whereby Georgia Power purchases their excess generation. During 2016, Georgia Power purchased 1.2 billion KWHs from such companies at a cost of $88 million. Georgia Power also has PPAs for electricity with six cogeneration facilities. Payments are subject to reductions for failure to meet minimum capacity output. During 2016, Georgia Power purchased 512 million KWHs at a cost of $38 million from these facilities.

Also during 2016, Georgia Power purchased energy from three customer-owned generating facilities. These customers provide only energy to Georgia Power, make no capacity commitment, and are not dispatched by Georgia Power. During 2016, Georgia Power purchased a total of 46 million KWHs from the three customers at a cost of approximately $2 million.

As of December 31, 2016, Gulf Power had agreements in effect with various industrial, commercial, and qualifying facilities pursuant to which Gulf Power purchases "as available" energy from customer-owned generation. During 2016, Gulf Power purchased 228 million KWHs from such companies for approximately $6 million.

As of December 31, 2016, Mississippi Power had one cogeneration agreement in effect with one of its industrial customers. Under the terms of this contract, Mississippi Power purchases any excess generation. During 2016, Mississippi Power did not purchase any excess generation from this customer.

Natural Gas

Southern Company Gas' regulated natural gas distribution utilities do not compete with other distributors of natural gas in their exclusive franchise territories but face competition from other energy products. Their principal competitors are electric utilities and fuel oil and propane providers serving the residential, commercial, and industrial markets in their service areas for customers who are considering switching to or from a natural gas appliance. Competition for heating as well as general household and small commercial energy needs generally occurs at the initial installation phase when the customer or builder makes decisions as to which types of equipment to install. Customers generally use the chosen energy source for the life of the equipment.

Customer demand for natural gas could be affected by numerous factors, including:

- changes in the availability or price of natural gas and other forms of energy;
- general economic conditions;
- energy conservation, including state-supported energy efficiency programs;
- legislation and regulations;
- the cost and capability to convert from natural gas to alternative energy products; and
- technological changes resulting in displacement or replacement of natural gas appliances.

Southern Company Gas continues to develop and grow its business through the use of a variety of targeted marketing programs designed to attract new customers and to retain existing customers. These efforts include working to add residential customers, multifamily complexes, and commercial customers who might use natural gas, as well as evaluating and launching new natural gas related programs, products, and services to enhance customer growth, mitigate customer attrition, and increase operating revenues.

The natural gas-related programs generally emphasize natural gas as the fuel of choice for customers and seek to expand the use of natural gas through a variety of promotional activities. In addition, Southern Company Gas partners with third-party entities to market the benefits of natural gas appliances.

Recent advances in natural gas drilling in shale producing regions of the U.S. have resulted in historically high supplies of natural gas and relatively low prices for natural gas. The availability and affordability of natural gas have provided cost advantages and further opportunity for growth of the businesses.

Seasonality

The demand for electric power and natural gas supply is affected by seasonal differences in the weather. In most of the areas the traditional electric operating companies serve, electric power sales peak during the summer, while in most of the areas Southern Company Gas serves, natural gas demand peaks during the winter. As a result, the overall operating results of Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas in the future may fluctuate substantially on a seasonal basis. In addition, Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas have historically sold less power and natural gas when weather conditions are milder.

Regulation

State Commissions

The traditional electric operating companies and the natural gas distribution utilities are subject to the jurisdiction of their respective state PSCs or applicable state regulatory agencies. These regulatory bodies have broad powers of supervision and regulation over public utilities operating in the respective states, including their rates, service regulations, sales of securities (except for the Mississippi PSC), and, in the cases of the Georgia PSC and the Mississippi PSC, in part, retail service territories. See "Territory Served by the Southern Company System" and "Rate Matters" herein for additional information.

Federal Power Act

The traditional electric operating companies, Southern Power Company and certain of its generation subsidiaries, and SEGCO are all public utilities engaged in wholesale sales of energy in interstate commerce and, therefore, are subject to the rate, financial, and accounting jurisdiction of the FERC under the Federal Power Act. The FERC must approve certain financings and allows an "at cost standard" for services rendered by system service companies such as SCS and Southern Nuclear. The FERC is also authorized to establish regional reliability organizations which enforce reliability standards, address impediments to the construction of transmission, and prohibit manipulative energy trading practices.

Alabama Power and Georgia Power are also subject to the provisions of the Federal Power Act or the earlier Federal Water Power Act applicable to licensees with respect to their hydroelectric developments. As of December 31, 2016, among the hydroelectric projects subject to licensing by the FERC are 14 existing Alabama Power generating stations having an aggregate

installed capacity of 1,670,000 KWs and 17 existing Georgia Power generating stations and one generating station partially owned by Georgia Power, with a combined aggregate installed capacity of 1,087,296 KWs.
In 2013, the FERC issued a new 30-year license to Alabama Power for Alabama Power's seven hydroelectric developments on the Coosa River (Weiss, Henry, Logan Martin, Lay, Mitchell, Jordan, and Bouldin). Alabama Power filed a petition requesting rehearing of the FERC order granting the relicense seeking revisions to several conditions of the license. Alabama Rivers Alliance, American Rivers, the Georgia Environmental Protection Division, and the Atlanta Regional Commission also filed petitions for rehearing of the FERC order. On April 21, 2016, the FERC issued an order granting in part and denying in part Alabama Power's rehearing request. The order also denied rehearing requests filed by Alabama Rivers Alliance, American Rivers, the Georgia Environmental Protection Division, and the Atlanta Regional Commission. On May 17, 2016, Alabama Rivers Alliance and American Rivers filed a second rehearing request and on June 15, 2016, also filed a petition for review at the U.S. Court of Appeals for the District of Columbia Circuit of the license and the rehearing denial order. The FERC issued an order on September 12, 2016 denying the second rehearing request, and American Rivers and Alabama Rivers Alliance subsequently filed an appeal of that order at the U.S. Court of Appeals for the District of Columbia Circuit. The U.S. Court of Appeals for the District of Columbia Circuit has consolidated the two appeals into one proceeding.
In 2013, Alabama Power filed an application with the FERC to relicense the Holt hydroelectric project located on the Warrior River. The current Holt license expired on August 31, 2015. Since the FERC did not act on Alabama Power's new license application prior to expiration, the FERC issued to Alabama Power an annual license authorizing continued operation of the project under the terms and conditions of the expired license until action is taken on the new license and, on December 22, 2016, issued a new 50-year license to Alabama Power.
In December 2015, the FERC issued a new 30-year license to Alabama Power for the Martin Dam project located on the Tallapoosa River. Alabama Rivers Alliance, American Rivers, the Georgia Environmental Protection Division, and the Atlanta Regional Commission filed petitions for rehearing of the FERC order, which the FERC denied on November 15, 2016.
In 2016, Georgia Power continued the process of developing an application to relicense the Wallace Dam project on the Oconee River. The current Wallace Dam project license will expire on June 1, 2020.
Georgia Power and OPC also have a license, expiring in 2027, for the Rocky Mountain Plant, a pure pumped storage facility of 847,800 KW capacity. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information.
Licenses for all projects, excluding those discussed above, expire in the years 2023-2040 in the case of Alabama Power's projects and in the years 2024-2044 in the case of Georgia Power's projects.
Upon or after the expiration of each license, the U.S. Government, by act of Congress, may take over the project or the FERC may relicense the project either to the original licensee or to a new licensee. In the event of takeover or relicensing to another, the original licensee is to be compensated in accordance with the provisions of the Federal Power Act, such compensation to reflect the net investment of the licensee in the project, not in excess of the fair value of the property, plus reasonable damages to other property of the licensee resulting from the severance therefrom of the property. The FERC may grant relicenses subject to certain requirements that could result in additional costs.
The ultimate outcome of these matters cannot be determined at this time.
Nuclear Regulation
Alabama Power, Georgia Power, and Southern Nuclear are subject to regulation by the NRC. The NRC is responsible for licensing and regulating nuclear facilities and materials and for conducting research in support of the licensing and regulatory process, as mandated by the Atomic Energy Act of 1954, as amended; the Energy Reorganization Act of 1974, as amended; and the Nuclear Nonproliferation Act of 1978, as amended; and in accordance with the National Environmental Policy Act of 1969, as amended, and other applicable statutes. These responsibilities also include protecting public health and safety, protecting the environment, protecting and safeguarding nuclear materials and nuclear power plants in the interest of national security, and assuring conformity with antitrust laws.
The NRC licenses for Georgia Power's Plant Hatch Units 1 and 2 expire in 2034 and 2038, respectively. The NRC licenses for Alabama Power's Plant Farley Units 1 and 2 expire in 2037 and 2041, respectively. The NRC licenses for

Plant Vogtle Units 1 and 2 expire in 2047 and 2049, respectively.
In 2012, the NRC issued combined construction and operating licenses (COLs) for Plant Vogtle Units 3 and 4. Receipt of the COLs allowed full construction to begin. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Nuclear Construction" of Georgia Power in Item 7 herein and Note 3 to the financial statements of Southern Company under "Regulatory Matters – Georgia Power – Nuclear Construction" and Georgia Power under "Retail Regulatory Matters – Nuclear Construction" in Item 8 herein for additional information.

See Notes 1 and 9 to the financial statements of Southern Company, Alabama Power, and Georgia Power in Item 8 herein for information on nuclear decommissioning costs and nuclear insurance.

Environmental Statutes and Regulations

The Southern Company system's electric utilities' 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. Included are laws and regulations regarding the handling and disposal of waste and release of hazardous substances from certain current and former operating sites, and locations affected by historical operations or subject to contractual obligations. Compliance with these existing environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions or through market-based contracts. There is no assurance, however, that all such costs will be recovered. For Southern Company Gas, substantially all of these costs are related to former manufactured gas plants (MGP) sites, which are primarily recovered through existing ratemaking provisions. See Note 3 to the financial statements of Southern Company Gas under "Environmental Matters" in Item 8 herein for additional information.

Compliance with federal environmental statutes and resulting regulations has been, and will continue to be, a significant focus for Southern Company, each traditional electric operating company, Southern Power, SEGCO, and Southern Company Gas. In addition, existing environmental laws and regulations may be changed or new laws and regulations may be adopted or otherwise become applicable to the Southern Company system, including laws and regulations designed to address air and water quality, wastes, greenhouse gases, endangered species or other environmental and health concerns. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company and each of the traditional electric operating companies in Item 7 herein for additional information about environmental issues, including, but not limited to, proposed and final regulations related to air quality, water quality, CCRs, and global climate issues. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Power in Item 7 herein for additional information about environmental issues and global climate issues. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company Gas in Item 7 herein for additional information about environmental remediation liabilities.

The Southern Company system's ultimate environmental compliance strategy, including potential electric generating unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations; the time periods over which compliance with regulations is required; individual state implementation of regulations, as applicable; the outcome of any legal challenges to the environmental rules; any additional rulemaking activities in response to legal challenges and court decisions; the cost, availability, and existing inventory of emissions allowances; the impact of future changes in generation and emissions-related technology; the fuel mix of the electric utilities; and environmental remediation requirements. 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. Environmental compliance spending over the next several years may differ materially from the amounts estimated. Such expenditures could affect results of operations, cash flows, and financial condition if such costs are not recovered on a timely basis through regulated rates for the traditional electric operating companies and the natural gas distribution utilities or through long-term wholesale agreements for the traditional electric operating companies and Southern Power. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for energy, which could negatively affect results of operations, cash flows, and financial condition. Also see MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company, each of the traditional electric operating companies, Southern Power, and Southern Company Gas in Item 7 herein for additional information. The ultimate outcome of these matters cannot be determined at this time.

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 Southern Company system. Although new or revised environmental legislation or regulations could affect many areas of the electric utilities' and natural gas distribution utilities' operations, the full impact of any such changes cannot be determined at this time. Additionally, many 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 and natural gas. See "Construction Program" herein for additional information.

Rate Matters

Rate Structure and Cost Recovery Plans

Electric

The rates and service regulations of the traditional electric operating companies are uniform for each class of service throughout their respective retail service territories. Rates for residential electric service are generally of the block type based upon KWHs used and include minimum charges. Residential and other rates contain separate customer charges. Rates for commercial service are presently of the block type and, for large customers, the billing demand is generally used to determine capacity and minimum bill charges. These large customers' rates are generally based upon usage by the customer and include rates with special features to encourage off-peak usage. Additionally, Alabama Power, Gulf Power, and Mississippi Power are generally allowed by their respective state PSCs to negotiate the terms and cost of service to large customers. Such terms and cost of service, however, are subject to final state PSC approval.

The traditional electric operating companies recover their respective costs through a variety of forward-looking, cost-based rate mechanisms. Fuel and net purchased energy costs are recovered through specific fuel cost recovery provisions. These fuel cost recovery provisions are adjusted to reflect increases or decreases in such costs as needed or on schedules as required by the respective PSCs. Approved environmental compliance, storm damage, and certain other costs are recovered at Alabama Power, Gulf Power, and Mississippi Power through specific cost recovery mechanisms approved by their respective PSCs. Certain similar costs at Georgia Power are recovered through various base rate tariffs as approved by the Georgia PSC. Costs not recovered through specific cost recovery mechanisms are recovered at Alabama Power and Mississippi Power through annual, formulaic cost recovery proceedings and at Georgia Power and Gulf Power through base rate proceedings.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Regulatory Matters" of Southern Company and each of the traditional electric operating companies in Item 7 herein and Note 3 to the financial statements of Southern Company and each of the traditional electric operating companies under "Retail Regulatory Matters" in Item 8 herein for a discussion of rate matters and certain cost recovery mechanisms. Also, see Note 1 to the financial statements of Southern Company and each of the traditional electric operating companies in Item 8 herein for a discussion of recovery of fuel costs, storm damage costs, and environmental compliance costs through rate mechanisms.

See "Integrated Resource Planning" herein for a discussion of Georgia PSC certification of new demand-side or supply-side resources and decertification of existing supply-side resources for Georgia Power. In addition, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Nuclear Construction" of Georgia Power in Item 7 herein and Note 3 to the financial statements of Southern Company under "Regulatory Matters – Georgia Power – Nuclear Construction" and Georgia Power under "Retail Regulatory Matters – Nuclear Construction" in Item 8 herein for a discussion of the Georgia Nuclear Energy Financing Act and the Georgia PSC certification of Plant Vogtle Units 3 and 4, which have allowed Georgia Power to recover financing costs for construction of Plant Vogtle Units 3 and 4 during the construction period beginning in 2011.

See Note 3 to the financial statements of Southern Company and Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 herein and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs" of Mississippi Power in Item 7 herein for information on cost recovery plans with respect to the Kemper IGCC.

The traditional electric operating companies and Southern Power Company and certain of its generation subsidiaries are authorized by the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "FERC Matters" of each of the registrants in Item 7 herein for information on the traditional electric operating companies' and Southern Power Company's market-based rate authority and a pending FERC proceeding relating to this authority.

Through 2015, long-term non-affiliate capacity sales from Gulf Power's ownership of Plant Scherer Unit 3 (205 MWs) provided the majority of Gulf Power's wholesale earnings. Contract expirations at the end of 2015 and the end of May 2016 related to Plant Scherer Unit 3 wholesale services had a material negative impact on Gulf Power's earnings in

2016 but did not have a material impact on Southern Company's earnings in 2016. Remaining contract sales from Plant Scherer Unit 3 cover approximately 24% of Gulf Power's ownership of the unit through 2019. On October 12, 2016, Gulf Power filed a petition (2016 Rate Case) with the Florida PSC requesting an annual increase in retail rates and charges of $106.8 million based on the projected test year of January 1, 2017 through December 31, 2017 and a retail return on equity (ROE) of 11% compared to the current retail ROE of 10.25%. The requested increase includes recovery of the portion of Plant Scherer Unit 3 that has been rededicated to serving retail customers following the contract expirations discussed above. If retail recovery of Plant Scherer Unit 3 is not approved by the Florida PSC in the 2016 Rate Case, Gulf Power may consider an asset sale. The current book value of Gulf Power's ownership of Plant Scherer Unit 3 could exceed market value which could result in a material loss. The Florida PSC is expected to make a decision on the 2016 Rate Case in the second quarter 2017. Gulf Power has requested that the increase in base rates, if approved by the Florida PSC, become effective in July 2017. On November 2, 2016, the Florida PSC approved Gulf Power's 2017 annual cost recovery clause factors. The fuel and environmental factors include certain costs associated with the ongoing ownership and operation of Plant Scherer Unit 3. The final disposition of these costs, and the related impact on rates, is subject to the Florida PSC's ultimate ruling on whether costs associated with Plant Scherer Unit 3 are recoverable from retail customers, which is expected to be decided by the Florida PSC in the 2016 Rate Case.

Mississippi Power serves long-term contracts with rural electric cooperative associations and a municipality located in southeastern Mississippi under cost-based electric tariffs which are subject to regulation by the FERC. The contracts with these wholesale customers represented 19.8% of Mississippi Power's operating revenues in 2016 and are largely subject to rolling 10-year cancellation notices. Historically, these wholesale customers have acted as a group and any changes in contractual relationships for one customer are likely to be followed by the other wholesale customers.

Natural Gas

Southern Company Gas' seven natural gas distribution utilities are subject to regulations and oversight by their respective state regulatory agencies with respect to rates charged to their customers, maintenance of accounting records, and various service and safety matters. Rates charged to these customers vary according to customer class (residential, commercial, or industrial) and rate jurisdiction. These agencies approve rates designed to provide Southern Company Gas the opportunity to generate revenues to recover all prudently incurred costs, including a return on rate base sufficient to pay interest on debt, and provide a reasonable return. Rate base generally consists of the original cost of the utility plant in service, working capital, and certain other assets, less accumulated depreciation on the utility plant in service and net deferred income tax liabilities, and may include certain other additions or deductions.

With the exception of Atlanta Gas Light Company, which operates in a deregulated environment in which gas marketers rather than a traditional utility sell natural gas to end-use customers and earns revenue by charging rates to its customers based primarily on monthly fixed charges that are set by the Georgia PSC, the earnings of the natural gas distribution utilities can be affected by customer consumption patterns that are largely a function of weather conditions and price levels for natural gas.

The natural gas distribution utilities, excluding Atlanta Gas Light Company, are authorized to use natural gas cost recovery mechanisms that allow them to adjust their rates to reflect changes in the wholesale cost of natural gas and to ensure they recover all of the costs prudently incurred in purchasing gas for their customers. In addition to natural gas cost recovery mechanisms, the natural gas distribution utilities have other cost recovery mechanisms, such as regulatory riders, which vary by utility but allow recovery of certain costs, such as those related to infrastructure replacement programs as well as environmental remediation and energy efficiency plans.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Regulatory Matters – Utility Regulation and Rate Design" of Southern Company Gas in Item 7 herein and Note 3 to the financial statements of Southern Company Gas under "Regulatory Matters" in Item 8 herein for a discussion of rate matters and certain cost recovery mechanisms.

Integrated Resource Planning

Each of the traditional electric operating companies continually evaluates its electric generating resources in order to ensure that it maintains a cost-effective and reliable mix of resources to meet the existing and future demand requirements of its customers. See "Environmental Statutes and Regulations" above for a discussion of existing and potential environmental regulations that may impact the future generating resource needs of the traditional electric operating companies.

Certain of the traditional electric operating companies are required to file IRPs with their respective state PSC as discussed below.

Georgia Power

Triennially, Georgia Power must file an IRP with the Georgia PSC that specifies how it intends to meet the future electrical needs of its customers through a combination of demand-side and supply-side resources. The Georgia PSC, under state law, must certify any new demand-side or supply-side resources for Georgia Power to receive cost recovery. Once certified, the lesser of actual or certified construction costs and purchased power costs is recoverable through rates. Certified costs may be excluded from recovery only on the basis of fraud, concealment, failure to disclose a material fact, imprudence, or criminal misconduct.

See Note 3 to the financial statements of Southern Company under "Regulatory Matters – Georgia Power – Rate Plans," "– Integrated Resource Plan," and "– Nuclear Construction" and Note 3 to the financial statements of Georgia Power under "Retail

Regulatory Matters – Rate Plans," "– Integrated Resource Plan," and "– Nuclear Construction" in Item 8 herein for additional information.

Gulf Power

Annually by April 1, Gulf Power must file a 10-year site plan with the Florida PSC containing Gulf Power's estimate of its power-generating needs in the period and the general location of its proposed power plant sites. The 10-year site plans submitted by the state's electric utilities are reviewed by the Florida PSC and subsequently classified as either "suitable" or "unsuitable." The Florida PSC then reports its findings along with any suggested revisions to the Florida Department of Environmental Protection for its consideration at any subsequent electrical power plant site certification proceedings. Under Florida law, any 10-year site plans submitted by an electric utility are considered tentative information for planning purposes only and may be amended at any time at the discretion of the utility with written notification to the Florida PSC.

Gulf Power's most recent 10-year site plan was classified by the Florida PSC as "suitable" in November 2016. Gulf Power's most recent 10-year site plan and environmental compliance plan identify environmental regulations and potential legislation or regulation that would impose mandatory restrictions on greenhouse gas emissions. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality," "– Environmental Statutes and Regulations – Coal Combustion Residuals," and "– Global Climate Issues" of Gulf Power in Item 7 herein. Gulf Power continues to evaluate the economics of various potential planning scenarios for units at certain Gulf Power coal-fired generating plants as EPA and other regulations develop.

As a result of the cost to comply with environmental regulations imposed by the EPA, Gulf Power retired its coal-fired generation at Plant Smith Units 1 and 2 (357 MWs) on March 31, 2016. Gulf Power filed a petition with the Florida PSC requesting permission to recover the remaining net book value of Plant Smith Units 1 and 2 and the remaining materials and supplies associated with these units as of the retirement date. On August 29, 2016, the Florida PSC approved Gulf Power's request to reclassify these costs, totaling approximately $63 million, to a regulatory asset for recovery over a period to be decided in the 2016 Rate Case. The ultimate outcome of this matter cannot be determined at this time.

Mississippi Power

Mississippi Power's 2010 IRP indicated that Mississippi Power plans to construct the Kemper IGCC to meet its identified needs, to add environmental controls at Plant Daniel Units 1 and 2, to defer environmental controls at Plant Watson Units 4 and 5, and to continue operation of the combined cycle Plant Daniel Units 3 and 4. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" and "– Global Climate Issues" of Mississippi Power in Item 7 herein. In 2014, Mississippi Power entered into a settlement agreement with the Sierra Club that, among other things, required the Sierra Club to dismiss or withdraw all pending legal and regulatory challenges to the Kemper IGCC and the flue gas desulfurization system project at Plant Daniel Units 1 and 2, which also occurred in 2014. In addition, and consistent with Mississippi Power's ongoing evaluation of recent environmental rules and regulations, Mississippi Power agreed to retire, repower with natural gas, or convert to an alternative non-fossil fuel source Plant Sweatt Units 1 and 2 (80 MWs) no later than December 2018 (and the units were retired in July 2016). Mississippi Power also agreed that it would cease burning coal or other solid fuel at Plant Watson Units 4 and 5 (750 MWs) and begin operating those units solely on natural gas no later than April 2015 (which occurred in April 2015) and cease burning coal and other solid fuel at Plant Greene County Units 1 and 2 (200 MWs) no later than April 2016 (which occurred in February and March 2016, respectively), and begin operating those units solely on natural gas (which occurred in June and July 2016, respectively).

For information regarding Mississippi Power's construction of the Kemper IGCC, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" of Mississippi Power in Item 7 herein and Note 3 to the financial statements of Southern Company and Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 herein.

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

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Employee Relations

The Southern Company system had a total of 32,015 employees on its payroll at December 31, 2016.

	Employees at December 31, 2016
Alabama Power	6,805
Georgia Power	7,527
Gulf Power	1,352
Mississippi Power	1,484
PowerSecure	1,051
SCS	4,341
Southern Company Gas	5,292
Southern Nuclear	3,928
Southern Power*	0
Other	235
Total	32,015

* Southern Power has no employees. Southern Power has agreements with SCS and the traditional electric operating companies whereby employee services are rendered at amounts in compliance with FERC regulations.

The traditional electric operating companies and the natural gas distribution utilities have separate agreements with local unions of the IBEW and the Utilities Workers Union of America generally covering wages, working conditions, and procedures for handling grievances and arbitration. These agreements apply with certain exceptions to operating, maintenance, and construction employees.

Alabama Power has agreements with the IBEW in effect through August 15, 2019. Upon notice given at least 60 days prior to that date, negotiations may be initiated with respect to agreement terms to be effective after such date.

Georgia Power has an agreement with the IBEW covering wages and working conditions, which is in effect through June 30, 2021.

Gulf Power has an agreement with the IBEW covering wages and working conditions, which is in effect through April 15, 2019. Upon notice given at least 60 days prior to that date, negotiations may be initiated with respect to agreement terms to be effective after such date.

Mississippi Power has an agreement with the IBEW covering wages and working conditions, which is in effect through May 1, 2019. In 2013, Mississippi Power signed a separate agreement with the IBEW related solely to the Kemper IGCC; the current agreement is in effect through March 15, 2021.

Southern Nuclear has a five-year agreement with the IBEW covering certain employees at Plants Hatch and Vogtle which is in effect through June 30, 2021. A five-year agreement between Southern Nuclear and the IBEW representing certain employees at Plant Farley is in effect through August 15, 2019. Upon notice given at least 60 days prior to that date, negotiations may be initiated with respect to agreement terms to be effective after such date.

The agreements also make the terms of the pension plans for the companies discussed above subject to collective bargaining with the unions at either a five-year or a 10-year cycle, depending upon union and company actions.

The natural gas distribution utilities have separate agreements with local unions of the IBEW and Utilities Workers Union of America covering wages, working conditions, and procedures for handling grievances and arbitration. Nicor Gas' agreement with the IBEW is effective through February 28, 2018. Virginia Natural Gas, Inc.'s agreement with the IBEW is effective through May 16, 2019. Elizabethtown Gas' agreement with the Utility Workers Union of America is effective through November 20, 2019. The agreements also make the terms of the Southern Company Gas pension plan subject to collective bargaining with the unions when significant changes to the benefit accruals are considered by Southern Company Gas.

Item 1A. RISK FACTORS

In addition to the other information in this Form 10-K, including MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL in Item 7 of each registrant, and other documents filed by Southern Company and/or its subsidiaries with the SEC from time to time, the following factors should be carefully considered in evaluating Southern Company and its subsidiaries. Such factors could affect actual results and cause results to differ materially from those expressed in any forward-looking statements made by, or on behalf of, Southern Company and/or its subsidiaries.

UTILITY REGULATORY, LEGISLATIVE, AND LITIGATION RISKS

Southern Company and its subsidiaries are subject to substantial governmental regulation. Compliance with current and future regulatory requirements and procurement of necessary approvals, permits, and certificates may result in substantial costs to Southern Company and its subsidiaries.

Southern Company and its subsidiaries, including the traditional electric operating companies, Southern Power, and Southern Company Gas, are subject to substantial regulation from federal, state, and local regulatory agencies. Southern Company and its subsidiaries are required to comply with numerous laws and regulations and to obtain numerous permits, approvals, and certificates from the governmental agencies that regulate various aspects of their businesses, including rates and charges, service regulations, retail service territories, sales of securities, sales and marketing of energy-related products and services, incurrence of indebtedness, asset acquisitions and sales, accounting and tax policies and practices, physical and cyber security policies and practices, and the construction and operation of electric generating facilities, as well as transmission, storage, transportation, and distribution facilities for the electric and natural gas businesses. For example, the respective state PSC or other applicable state regulatory agency must approve the traditional electric operating companies' requested rates for retail electric customers and the natural gas distribution utilities' requested rates for gas distribution operations customers. The traditional electric operating companies and the natural gas distribution utilities seek to recover their costs (including a reasonable return on invested capital) through their retail rates, and a state PSC or other applicable state regulatory agency, in a future rate proceeding, may alter the timing or amount of certain costs for which recovery is allowed or modify the current authorized rate of return. Rate refunds may also be required. Additionally, the rates charged to wholesale customers by the traditional electric operating companies and by Southern Power must be approved by the FERC. These wholesale rates could be affected by changes to Southern Power's and the traditional electric operating companies' ability to conduct business pursuant to FERC market-based rate authority. The FERC rules related to retaining the authority to sell electricity at market-based rates in the wholesale markets are important for the traditional electric operating companies and Southern Power if they are to remain competitive in the wholesale markets in which they operate.

The impact of any future revision or changes in interpretations of existing regulations or the adoption of new laws and regulations applicable to Southern Company or any of its subsidiaries is uncertain. Changes in regulation or the imposition of additional regulations could influence the operating environment of Southern Company and its subsidiaries and may result in substantial costs or otherwise negatively affect their results of operations.

The Southern Company system's costs of compliance with environmental laws are significant. The costs of compliance with current and future environmental laws, including laws and regulations designed to address air quality, greenhouse gases (GHG), water quality, waste, and other matters and the incurrence of environmental liabilities could negatively impact the net income, cash flows, and financial condition of Southern Company, the traditional electric operating companies, Southern Power, and/or Southern Company Gas.

The Southern Company system is subject to extensive federal, state, and local environmental requirements which, among other things, regulate air emissions, GHG, water usage and discharge, release of hazardous substances, and the management and disposal of waste in order to adequately protect the environment. Compliance with these environmental requirements requires the traditional electric operating companies, Southern Power, and Southern Company Gas to commit significant expenditures, including installation and operation of pollution control equipment, environmental monitoring, emissions fees, remediation costs, and/or permits at substantially all of their respective facilities. Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas expect that these expenditures will continue to be significant in the future.

The EPA has adopted and is in the process of implementing regulations governing air and water quality, including the emission of nitrogen oxide, sulfur dioxide, fine particulate matter, ozone, mercury, and other air pollutants under the Clean Air Act and regulations governing cooling water intake structures and effluent guidelines for steam electric generating plants under the Clean Water Act. The EPA has also finalized regulations governing the disposal of CCR, including coal ash and gypsum, in landfills and surface impoundments at active power generation plants. The EPA has also finalized regulations, which are currently stayed by the U.S. Supreme Court, limiting CO_2 emissions from fossil fuel-fired electric generating units.

Additionally, environmental laws and regulations covering the handling and disposal of waste and release of hazardous substances could require the Southern Company system to incur substantial costs to clean up affected sites, including certain current and former operating sites, and locations affected by historical operations or subject to contractual obligations.

Existing environmental laws and regulations may be revised or new laws and regulations related to air quality, GHG, water quality, waste, endangered species, or other environmental and health concerns may be adopted or become applicable to the traditional electric operating companies, Southern Power, and/or Southern Company Gas.

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, releases of regulated substances, and alleged exposure to regulated substances, and/or requests for injunctive relief in connection with such matters.

The Southern Company system'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; the time periods over which compliance with regulations is required; individual state implementation of regulations, as applicable; the outcome of any legal challenges to the environmental rules and any additional rulemaking activities in response to legal challenges and court decisions; the cost, availability, and existing inventory of emissions allowances; the impact of future changes in generation and emissions-related technology and costs; and the fuel mix of the electric utilities. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, closure and groundwater monitoring of CCR facilities, and adding or changing fuel sources for existing units.

Environmental compliance spending over the next several years may differ materially from the amounts estimated. Such expenditures could affect unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered on a timely basis through regulated rates for the traditional electric operating companies and the natural gas distribution utilities or through long-term wholesale agreements for the traditional electric operating companies and Southern Power. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for energy, which could negatively affect results of operations, cash flows, and financial condition. Additionally, if Southern Company, any traditional electric operating company, Southern Power, or Southern Company Gas fails to comply with environmental laws and regulations, even if caused by factors beyond its control, that failure may result in the assessment of civil or criminal penalties and fines and/or remediation costs.

The Southern Company system may be exposed to regulatory and financial risks related to the impact of climate change legislation and regulation.

Since the late 1990s, the U.S. Congress, the EPA, federal courts, and various states have considered, and at times have adopted, climate change policies and proposals to reduce GHG emissions, mandate renewable energy, and/or impose energy efficiency standards. Clean Air Act regulation and/or future GHG or renewable energy legislation requiring limits or reductions in emissions could cause the Southern Company system to incur expenditures and make fundamental business changes to achieve limits and reduce GHG emissions. Internationally, the United Nations Framework Convention on Climate Change, which the United States has ratified, considers addressing climate change. The 21st Conference of the Parties met in late 2015 and resulted in the adoption of the Paris Agreement, which established a non-binding universal framework for addressing GHG emissions based on nationally determined contributions.

In October 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 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. The proposed guidelines and standards could result in operational restrictions and material compliance costs, including capital expenditures, which could affect future unit retirement and replacement decisions. 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.
Costs associated with these actions could be significant to the utility industry and the Southern Company system. However, the ultimate financial and operational impact of the final rules on the Southern Company system cannot be determined at this time and will depend upon numerous factors, including the Southern Company system's ongoing review of the final rules; the outcome of legal challenges, including legal challenges filed by the traditional electric 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 electric

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 generation capacity; and the time periods over which compliance will be required.
Because natural gas is a fossil fuel with lower carbon content relative to other traditional fuels, future carbon constraints may create additional demand for natural gas, both for production of electricity and direct use in homes and businesses. The impact is already being seen in the power production sector due to both environmental regulations and low natural gas costs. Future regulation of methane, a GHG and primary constituent of natural gas, could likewise result in increased costs to the Southern Company system and affect the demand for natural gas as well as the prices charged to customers and the competitive position of natural gas.
The net income of Southern Company, the traditional electric operating companies, and Southern Power could be negatively impacted by changes in regulations related to transmission planning processes and competition in the wholesale electric markets.
The traditional electric operating companies currently own and operate transmission facilities as part of a vertically integrated utility. A small percentage of transmission revenues are collected through the wholesale electric tariff but the majority of transmission revenues are collected through retail rates. FERC rules pertaining to regional transmission planning and cost allocation present challenges to transmission planning and the wholesale market structure in the Southeast. The key impacts of these rules include:

- possible disruption of the integrated resource planning processes within the states in the Southern Company system's service territory;
- delays and additional processes for developing transmission plans; and
- possible impacts on state jurisdiction of approving, certifying, and pricing new transmission facilities.

The FERC rules related to transmission are intended to spur the development of new transmission infrastructure to promote and encourage the integration of renewable sources of supply as well as facilitate competition in the wholesale market by providing more choices to wholesale power customers. In addition to the impacts on transactions contemplating physical delivery of energy, financial laws and regulations also impact power hedging and trading based on futures contracts and derivatives that are traded on various commodities exchanges as well as over-the-counter. Finally, technology changes in the power and fuel industries continue to create significant impacts to wholesale transaction cost structures. The impact of these and other such developments and the effect of changes in levels of wholesale supply and demand is uncertain. The financial condition, net income, and cash flows of Southern Company, the traditional electric operating companies, and Southern Power could be adversely affected by these and other changes.
The traditional electric operating companies and Southern Power could be subject to higher costs as a result of implementing and maintaining compliance with the North American Electric Reliability Corporation mandatory reliability standards along with possible associated penalties for non-compliance.
Owners and operators of bulk power systems, including the traditional electric operating companies, are subject to mandatory reliability standards enacted by the North American Electric Reliability Corporation and enforced by the FERC. Compliance with or changes in the mandatory reliability standards may subject the traditional electric operating companies and Southern Power to higher operating costs and/or increased capital expenditures. If any traditional electric operating company or Southern Power is found to be in noncompliance with the mandatory reliability standards, such traditional electric operating company or Southern Power could be subject to sanctions, including substantial monetary penalties.
Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas may be materially impacted by potential tax reform legislation.
Current proposals related to potential tax reform legislation are primarily focused on reducing the corporate income tax rate, allowing 100% of capital expenditures to be deducted, and eliminating the interest deduction. The ultimate impact of any tax reform proposals, including potential changes to the availability or realizability of investment tax credits and PTCs, is dependent upon the final form of any legislation enacted and the related transition rules and cannot be determined at this time, but could have a material impact on the financial statements of Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas.

OPERATIONAL RISKS

The financial performance of Southern Company and its subsidiaries may be adversely affected if the subsidiaries are unable to successfully operate their facilities or perform certain corporate functions.

The financial performance of Southern Company and its subsidiaries depends on the successful operation of the electric utilities' generating, transmission, and distribution facilities and Southern Company Gas' natural gas distribution and storage facilities and the successful performance of necessary corporate functions. There are many risks that could affect these operations and performance of corporate functions, including:

- operator error or failure of equipment or processes;
- accidents or explosions;
- operating limitations that may be imposed by environmental or other regulatory requirements;
- labor disputes;
- terrorist attacks (physical and/or cyber);
- fuel or material supply interruptions;
- transmission disruption or capacity constraints, including with respect to the Southern Company system's transmission, storage, and transportation facilities and third party transmission, storage, and transportation facilities;
- compliance with mandatory reliability standards, including mandatory cyber security standards;
- implementation of new technologies;
- information technology system failure;
- cyber intrusion;
- an environmental event, such as a spill or release; and
- catastrophic events such as fires, earthquakes, floods, droughts, hurricanes and other storms, pandemic health events such as influenzas, or other similar occurrences.

A decrease or elimination of revenues from the electric generation, transmission, or distribution facilities or natural gas distribution or storage facilities or an increase in the cost of operating the facilities would reduce the net income and cash flows and could adversely impact the financial condition of the affected traditional electric operating company, Southern Power, or Southern Company Gas and of Southern Company.

Operation of nuclear facilities involves inherent risks, including environmental, safety, health, regulatory, natural disasters, terrorism, and financial risks, that could result in fines or the closure of the nuclear units owned by Alabama Power or Georgia Power and which may present potential exposures in excess of insurance coverage.

Alabama Power owns, and contracts for the operation of, two nuclear units and Georgia Power holds undivided interests in, and contracts for the operation of, four existing nuclear units. The six existing units are operated by Southern Nuclear and represent approximately 3,680 MWs, or 8%, of the Southern Company system's electric generation capacity as of December 31, 2016. In addition, these units generated approximately 23% and 24% of the total KWHs generated by Alabama Power and Georgia Power, respectively, in the year ended December 31, 2016. In addition, Southern Nuclear, on behalf of Georgia Power and the other co-owners, is overseeing the construction of Plant Vogtle Units 3 and 4. Due solely to the increase in nuclear generating capacity, the below risks are expected to increase incrementally once Plant Vogtle Units 3 and 4 are operational. Nuclear facilities are subject to environmental, safety, health, operational, and financial risks such as:

- the potential harmful effects on the environment and human health and safety resulting from a release of radioactive materials in connection with the operation of nuclear facilities and the storage, handling, and disposal of radioactive material, including spent nuclear fuel;
- uncertainties with respect to the ability to dispose of spent nuclear fuel and the need for longer term on-site storage;
- uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of licensed lives and the ability to maintain and anticipate adequate capital reserves for decommissioning;
- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with the nuclear operations of Alabama Power and Georgia Power or those of other commercial nuclear facility owners in the U.S.;
- potential liabilities arising out of the operation of these facilities;
-

significant capital expenditures relating to maintenance, operation, security, and repair of these facilities, including repairs and upgrades required by the NRC;

- the threat of a possible terrorist attack, including a potential cyber security attack; and
- the potential impact of an accident or natural disaster.

It is possible that damages, decommissioning, or other costs could exceed the amount of decommissioning trusts or external insurance coverage, including statutorily required nuclear incident insurance.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance with NRC licensing and safety-related requirements, the NRC has the authority to impose fines and/or shut down any unit, depending upon its assessment of the severity of the situation, until compliance is achieved. NRC orders or regulations related to increased security measures and any future safety requirements promulgated by the NRC could require Alabama Power and Georgia Power to make substantial operating and capital expenditures at their nuclear plants. In addition, if a serious nuclear incident were to occur, it could result in substantial costs to Alabama Power or Georgia Power and Southern Company. A major incident at a nuclear facility anywhere in the world could cause the NRC to delay or prohibit construction of new nuclear units or require additional safety measures at new and existing units. Moreover, a major incident at any nuclear facility in the U.S., including facilities owned and operated by third parties, could require Alabama Power and Georgia Power to make material contributory payments.

In addition, potential terrorist threats and increased public scrutiny of utilities could result in increased nuclear licensing or compliance costs that are difficult to predict.

Transporting and storing natural gas involves risks that may result in accidents and other operating risks and costs.

Southern Company Gas' natural gas distribution and storage activities involve a variety of inherent hazards and operating risks, such as leaks, accidents, explosions, and mechanical problems, which could result in serious injury to employees and non-employees, loss of human life, significant damage to property, environmental pollution, and impairment of its operations. The location of pipelines and storage facilities near populated areas could increase the level of damage resulting from these risks. The occurrence of any of these events not fully covered by insurance could adversely affect Southern Company Gas' and Southern Company's financial condition and results of operations.

Physical or cyber attacks, both threatened and actual, could impact the ability of the traditional electric operating companies, Southern Power, and Southern Company Gas to operate and could adversely affect financial results and liquidity.

The traditional electric operating companies, Southern Power, and Southern Company Gas face the risk of physical and cyber attacks, both threatened and actual, against their respective generation and storage facilities, the transmission and distribution infrastructure used to transport energy, and their information technology systems and network infrastructure, which could negatively impact the ability of the traditional electric operating companies or Southern Power to generate, transport, and deliver power, or otherwise operate their respective facilities, or the ability of Southern Company Gas to distribute or store natural gas, or otherwise operate its facilities, in the most efficient manner or at all. In addition, physical or cyber attacks against key suppliers or service providers could have a similar effect on Southern Company and its subsidiaries.

The traditional electric operating companies, Southern Power, and Southern Company Gas operate in highly regulated industries that require the continued operation of sophisticated information technology systems and network infrastructure, which are part of interconnected distribution systems. In addition, in the ordinary course of business, the traditional electric operating companies, Southern Power, and Southern Company Gas collect and retain sensitive information, including personal identification information about customers, employees, and stockholders, and other confidential information. In some cases, administration of certain functions is outsourced to service providers that could be targets of cyber attacks. The traditional electric operating companies, Southern Power, and Southern Company Gas face on-going threats to their assets. Despite the implementation of robust security measures, all assets are potentially vulnerable to disability, failures, or unauthorized access due to human error, natural disasters, technological failure, or internal or external physical or cyber attacks. If the traditional electric operating companies', Southern Power's, or Southern Company Gas' assets were to fail, be physically damaged, or be breached and were not recovered in a timely way, the traditional electric operating companies, Southern Power, or Southern Company Gas may be unable to fulfill critical business functions, and sensitive and other data could be compromised. Any physical security breach, cyber breach or theft, damage, or improper disclosure of sensitive electronic data may also subject the applicable traditional electric operating company, Southern Power, or Southern Company Gas to penalties and claims from regulators or other third parties.

These events could harm the reputation of and negatively affect the financial results of Southern Company, the traditional electric operating companies, Southern Power, or Southern Company Gas through lost revenues, costs to

recover and repair damage, and costs associated with governmental actions in response to such attacks.
The Southern Company system may not be able to obtain adequate natural gas and other fuel supplies required to operate the traditional electric operating companies' and Southern Power's electric generating plants or serve Southern Company Gas' natural gas customers.
The traditional electric operating companies and Southern Power purchase fuel, including coal, natural gas, uranium, fuel oil, and biomass, as applicable, from a number of suppliers. Disruption in the delivery of fuel, including disruptions as a result of, among other things, transportation delays, weather, labor relations, force majeure events, or environmental regulations affecting

any of these fuel suppliers, could limit the ability of the traditional electric operating companies and Southern Power to operate certain facilities, which could result in higher fuel and operating costs and potentially reduce the net income of the affected traditional electric operating company or Southern Power and Southern Company.

Southern Company Gas' primary business is the distribution and sale of natural gas through its regulated and unregulated subsidiaries. Natural gas supplies can be subject to disruption in the event production or distribution is curtailed, such as in the event of a hurricane or a pipeline failure. Southern Company Gas also relies on natural gas pipelines and other storage and transportation facilities owned and operated by third parties to deliver natural gas to wholesale markets and to Southern Company Gas' distribution systems. The availability of shale gas and potential regulations affecting its accessibility may have a material impact on the supply and cost of natural gas. Disruption in natural gas supplies could limit the ability to fulfill these contractual obligations.

The traditional electric operating companies and Southern Power have become more dependent on natural gas for a portion of their electric generating capacity. In many instances, the cost of purchased power for the traditional electric operating companies and Southern Power is influenced by natural gas prices. Historically, natural gas prices have been more volatile than prices of other fuels. In recent years, domestic natural gas prices have been depressed by robust supplies, including production from shale gas. These market conditions, together with additional regulation of coal-fired generating units, have increased the traditional electric operating companies' reliance on natural gas-fired generating units.

The traditional electric operating companies are also dependent on coal for a portion of their electric generating capacity. The traditional electric operating companies depend on coal supply contracts, and the counterparties to these agreements may not fulfill their obligations to supply coal to the traditional electric operating companies. The suppliers under these agreements may experience financial or technical problems that inhibit their ability to fulfill their obligations to the traditional electric operating companies. In addition, the suppliers under these agreements may not be required to supply coal to the traditional electric operating companies under certain circumstances, such as in the event of a natural disaster. If the traditional electric operating companies are unable to obtain their coal requirements under these contracts, the traditional electric operating companies may be required to purchase their coal requirements at higher prices, which may not be recoverable through rates.

The revenues of Southern Company, the traditional electric operating companies, and Southern Power depend in part on sales under PPAs. The failure of a counterparty to one of these PPAs to perform its obligations, the failure of the traditional electric operating companies or Southern Power to satisfy minimum requirements under the PPAs, or the failure to renew the PPAs or successfully remarket the related generating capacity could have a negative impact on the net income and cash flows of the affected traditional electric operating company or Southern Power and of Southern Company.

Most of Southern Power's generating capacity has been sold to purchasers under PPAs. Southern Power's top three customers, Georgia Power, Duke Energy Corporation, and San Diego Gas & Electric accounted for 16.5%, 7.8%, and 5.7%, respectively, of Southern Power's total revenues for the year ended December 31, 2016. In addition, the traditional electric operating companies enter into PPAs with non-affiliated parties. Revenues are dependent on the continued performance by the purchasers of their obligations under these PPAs. The failure of one of the purchasers to perform its obligations could have a negative impact on the net income and cash flows of the affected traditional electric operating company or Southern Power and of Southern Company. Although the credit evaluations undertaken and contractual protections implemented by Southern Power and the traditional electric operating companies take into account the possibility of default by a purchaser, actual exposure to a default by a purchaser may be greater than predicted or specified in the applicable contract.

Additionally, neither Southern Power nor any traditional electric operating company can predict whether the PPAs will be renewed at the end of their respective terms or on what terms any renewals may be made. As an example, Gulf Power had long-term sales contracts to cover 100% of its ownership share of Plant Scherer Unit 3 (205 MWs) and these capacity revenues represented 82% of Gulf Power's total wholesale capacity revenues for 2015. Following contract expirations at the end of 2015 and the end of May 2016, Gulf Power's remaining contracted sales from the unit cover approximately 24% of Gulf Power's ownership of the unit through 2019. The expiration of these contracts had a material negative impact on Gulf Power's earnings in 2016 and may continue to have a material negative impact in future years. In addition, the failure of the traditional electric operating companies or Southern Power to satisfy minimum operational or availability requirements under these PPAs could result in payment of damages or termination of the PPAs.

The asset management arrangements between Southern Company Gas' wholesale gas services and Southern Company Gas' regulated operating companies, and between Southern Company Gas' wholesale gas services and its non-affiliated customers, may not be renewed or may be renewed at lower levels, which could have a significant impact on Southern Company Gas' financial results.

Southern Company Gas' wholesale gas services currently manages the storage and transportation assets of Atlanta Gas Light Company, Virginia Natural Gas, Inc., Elizabethtown Gas, Florida City Gas, Chattanooga Gas Company, and Elkton Gas. The profits earned from the management of these affiliate assets are shared with the respective affiliate's customers (and for Atlanta Gas Light Company with the Georgia PSC's Universal Service Fund), except for Chattanooga Gas Company and Elkton Gas where wholesale gas services are provided under annual fixed-fee agreements. These asset management agreements are subject to regulatory approval and such agreements may not be renewed or may be renewed with less favorable terms.

Southern Company Gas' wholesale gas services also has asset management agreements with certain non-affiliated customers and its financial results could be significantly impacted if these agreements are not renewed or are amended or renewed with less favorable terms. Sustained low natural gas prices could reduce the demand for these types of asset management arrangements.

Increased competition could negatively impact Southern Company's and its subsidiaries' revenues, results of operations, and financial condition.

The energy industry is highly competitive and complex and the Southern Company system faces increasing competition from other companies that supply energy or generation and storage technologies. Changes in technology may make the Southern Company system's electric generating facilities owned by the traditional electric operating companies and Southern Power less competitive. Southern Company Gas' business is dependent on natural gas prices remaining competitive as compared to other forms of energy. Southern Company Gas also faces competition in its unregulated markets.

A key element of the business models of the traditional electric operating companies and Southern Power is that generating power at central station power plants achieves economies of scale and produces power at a competitive cost. There are distributed generation and storage technologies that produce and store power, including fuel cells, microturbines, wind turbines, solar cells, and batteries. Advances in technology or changes in laws or regulations could reduce the cost of these or other alternative methods of producing power to a level that is competitive with that of most central station power electric production or result in smaller-scale, more fuel efficient, and/or more cost effective distributed generation that allows for increased self-generation by customers. Broader use of distributed generation by retail energy customers may also result from customers' changing perceptions of the merits of utilizing existing generation technology or tax or other economic incentives. Additionally, a state PSC or legislature may modify certain aspects of the traditional electric operating companies' business as a result of these advances in technology.

It is also possible that rapid advances in central station power generation technology could reduce the value of the current electric generating facilities owned by the traditional electric operating companies and Southern Power. Changes in technology could also alter the channels through which electric customers buy or utilize power, which could reduce the revenues or increase the expenses of Southern Company, the traditional electric operating companies, or Southern Power.

Southern Company Gas' gas marketing services is affected by competition from other energy marketers providing similar services in Southern Company Gas' service territories, most notably in Illinois and Georgia. Southern Company Gas' wholesale gas services competes for sales with national and regional full-service energy providers, energy merchants and producers, and pipelines based on the ability to aggregate competitively-priced commodities with transportation and storage capacity. Southern Company Gas competes with natural gas facilities in the Gulf Coast region of the U.S., as the majority of the existing and proposed high deliverability salt-dome natural gas storage facilities in North America are located in the Gulf Coast region. Storage values have begun to recover from the declines experienced over the past several years due to low natural gas prices and low volatility and Southern Company Gas expects this trend to continue during the remainder of 2017.

If new technologies become cost competitive and achieve sufficient scale, the market share of the traditional electric operating companies, Southern Power, and Southern Company Gas could be eroded, and the value of their respective electric generating facilities or natural gas distribution and storage facilities could be reduced. Additionally, Southern Company Gas' market share could be reduced if Southern Company Gas cannot remain price competitive in its unregulated markets. If state PSCs or other applicable state regulatory agencies fail to adjust rates to reflect the impact of any changes in loads, increasing self-generation, and the growth of distributed generation, the financial condition, results of operations, and cash flows of Southern Company and the affected traditional electric operating company or

Southern Company Gas could be materially adversely affected.

Failure to attract and retain an appropriately qualified workforce could negatively impact Southern Company's and its subsidiaries' results of operations.

Events such as an aging workforce without appropriate replacements, mismatch of skill sets to future needs, or unavailability of contract resources may lead to operating challenges such as lack of resources, loss of knowledge, and a lengthy time period associated with skill development, including with the workforce needs associated with major construction projects and ongoing operations. The Southern Company system's costs, including costs for contractors to replace employees, productivity costs, and safety costs, may rise. Failure to hire and adequately obtain replacement employees, including the ability to transfer significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect Southern Company and its subsidiaries' ability to manage and operate their businesses. If Southern Company and its subsidiaries are unable to successfully attract and retain an appropriately qualified workforce, results of operations could be negatively impacted.

CONSTRUCTION RISKS

Southern Company, the traditional electric operating companies, Southern Power, and/or Southern Company Gas may incur additional costs or delays in the construction of new plants or other facilities and may not be able to recover their investments. Also, existing facilities of the traditional electric operating companies, Southern Power, and Southern Company Gas require ongoing capital expenditures, including those to meet environmental standards.

General

The businesses of the registrants require substantial capital expenditures for investments in new facilities and, for the traditional electric operating companies, capital improvements to transmission, distribution, and generation facilities, and, for Southern Company Gas, capital improvements to natural gas distribution and storage facilities, including those to meet environmental standards. Certain of the traditional electric operating companies and Southern Power are in the process of constructing new generating facilities and adding environmental controls equipment at existing generating facilities. Southern Company Gas is replacing certain pipelines in its natural gas distribution system and is involved in three new gas pipeline construction projects. The Southern Company system intends to continue its strategy of developing and constructing other new facilities, expanding or updating existing facilities, and adding environmental control equipment. These types of projects are long term in nature and in some cases include the development and construction of facilities with designs that have not been finalized or previously constructed. The completion of these types of projects without delays or significant cost overruns is subject to substantial risks, including:

- shortages and inconsistent quality of equipment, materials, and labor;
- changes in labor costs and productivity;
- work stoppages;
- contractor or supplier delay or non-performance under construction, operating, or other agreements or non-performance by other major participants in construction projects;
- delays in or failure to receive necessary permits, approvals, tax credits, and other regulatory authorizations;
- delays associated with start-up activities, including major equipment failure and system integration, and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by any PSC or other applicable state regulatory agency);
- operational readiness, including specialized operator training and required site safety programs;
- impacts of new and existing laws and regulations, including environmental laws and regulations;
- the outcome of legal challenges to projects, including legal challenges to regulatory approvals;
- failure to construct in accordance with permitting and licensing requirements;
- failure to satisfy any environmental performance standards and the requirements of tax credits and other incentives;
- continued public and policymaker support for such projects;
- adverse weather conditions or natural disasters;
- other unforeseen engineering or design problems;
- changes in project design or scope;
- environmental and geological conditions;
- delays or increased costs to interconnect facilities to transmission grids; and
- unanticipated cost increases, including materials and labor, and increased financing costs as a result of changes in market interest rates or as a result of construction schedule delays.

If a traditional electric operating company, Southern Power, or Southern Company Gas is unable to complete the development or construction of a project or decides to delay or cancel construction of a project, it may not be able to recover its investment in that project and may incur substantial cancellation payments under equipment purchase orders or construction contracts. Additionally, each Southern Company Gas pipeline construction project involves separate joint venture participants. Even if a construction project (including a joint venture construction project) is completed, the total costs may be higher than estimated and the applicable traditional electric operating company or the natural gas distribution utility may not be able to recover such expenditures through regulated rates. In addition,

construction delays and contractor performance shortfalls can result in the loss of revenues and may, in turn, adversely affect the net income and financial position of a traditional electric operating company, Southern Power, or Southern Company Gas and of Southern Company.
Construction delays could result in the loss of otherwise available investment tax credits, PTCs, and other tax incentives. Furthermore, if construction projects are not completed according to specification, a traditional electric operating company, Southern Power, or Southern Company Gas and Southern Company may incur liabilities and suffer reduced plant efficiency, higher operating costs, and reduced net income.

Once facilities become operational, ongoing capital expenditures are required to maintain reliable levels of operation. Significant portions of the traditional electric operating companies' existing facilities were constructed many years ago. Older equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures to maintain efficiency, to comply with changing environmental requirements, or to provide safe and reliable operations.

The two largest construction projects currently underway in the Southern Company system are the construction of Plant Vogtle Units 3 and 4 and the Kemper IGCC. In addition, Southern Power has 567 MWs of natural gas and renewable generation under construction at three project sites.

Plant Vogtle Units 3 and 4 construction and rate recovery

Southern Nuclear, on behalf of Georgia Power and the other co-owners, is overseeing the construction of and will operate Plant Vogtle Units 3 and 4 (each, an approximately 1,100 MW AP1000 nuclear generating unit). Georgia Power owns 45.7% of the new units. There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, at the federal and state level, and additional challenges may arise as construction proceeds.

Under the terms of the engineering, procurement, and construction contract between the Vogtle Owners and the Contractor (Vogtle 3 and 4 Agreement), the Vogtle Owners agreed to pay a purchase price subject to certain price escalations and adjustments, including fixed escalation amounts and index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. The Vogtle 3 and 4 Agreement also provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees, subject to an aggregate cap of 10% of the contract price, or approximately $920 million to $930 million. In addition, the Vogtle 3 and 4 Agreement provides for limited cost sharing by the Vogtle Owners for Contractor costs under certain conditions (which Georgia Power has not been notified have occurred), with maximum additional capital costs under this provision attributable to Georgia Power (based on Georgia Power's ownership interest) of approximately $114 million. Each Vogtle Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Contractor under the Vogtle 3 and 4 Agreement. Georgia Power's proportionate share is 45.7%. In the event of certain credit rating downgrades of any Vogtle Owner, such Vogtle Owner will be required to provide a letter of credit or other credit enhancement.

Certain obligations of Westinghouse have been guaranteed by Toshiba Corporation (Toshiba), Westinghouse's parent company. In the event of certain credit rating downgrades of Toshiba, Westinghouse is required to provide letters of credit or other credit enhancement. In December 2015, Toshiba experienced credit rating downgrades and Westinghouse provided the Vogtle Owners with $920 million of letters of credit. These letters of credit remain in place in accordance with the terms of the Vogtle 3 and 4 Agreement.

On February 14, 2017, Toshiba announced preliminary earnings results for the period ended December 31, 2016, which included a substantial goodwill impairment charge at Westinghouse attributed to increased cost estimates to complete its U.S. nuclear projects, including Plant Vogtle Units 3 and 4. Toshiba also warned that it will likely be in a negative equity position as a result of the charges. At the same time, Toshiba reaffirmed its commitment to its U.S. nuclear projects with implementation of management changes and increased oversight. An inability or failure by the Contractor to perform its obligations under the Vogtle 3 and 4 Agreement could have a material impact on the construction of Plant Vogtle Units 3 and 4.

Under the terms of the Vogtle 3 and 4 Agreement, the Contractor does not have a right to terminate the Vogtle 3 and 4 Agreement for convenience. The Contractor may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including certain Vogtle Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Vogtle Owners, Vogtle Owner insolvency, and certain other events. In the event of an abandonment of work by the Contractor, the maximum liability of the Contractor under the Vogtle 3 and 4 Agreement is increased significantly, but remains subject to limitations. The Vogtle Owners may terminate the Vogtle 3 and 4 Agreement at any time for convenience, provided that the Vogtle Owners will be required to pay certain termination costs.

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4 with a certified capital cost of $4.418 billion. On December 20, 2016, the Georgia PSC voted to approve a settlement agreement (Vogtle Cost

Settlement Agreement) resolving certain prudence matters, including that (i) the in-service capital cost forecast will be adjusted to $5.680 billion (Revised Forecast), which includes a contingency of $240 million above Georgia Power's current forecast of $5.440 billion, (ii) capital costs incurred up to the Revised Forecast will be presumed to be reasonable and prudent with the burden of proof on any party challenging such costs, and (iii) Georgia Power would have the burden to show that any capital costs above the Revised Forecast are reasonable and prudent.

Under the terms of the Vogtle Cost Settlement Agreement, the certified in-service capital cost for purposes of calculating Georgia Power's Nuclear Construction Cost Recovery (NCCR) tariff will remain at $4.418 billion. Construction capital costs above $4.418 billion will accrue allowance for funds used during construction (AFUDC) through the date each unit is placed in service. The ROE used to calculate the NCCR tariff was reduced from 10.95% (the ROE rate setting point authorized by the

Georgia PSC in the Alternative Rate Plan approved by the Georgia PSC for the years 2014 through 2016) to 10.00% effective January 1, 2016. For purposes of the AFUDC calculation, the ROE on costs between $4.418 billion and $5.440 billion will also be 10.00% and the ROE on any amounts above $5.440 billion would be Georgia Power's average cost of long-term debt. If the Georgia PSC adjusts Georgia Power's ROE rate setting point in a rate case prior to Plant Vogtle Units 3 and 4 being placed into retail rate base, then the ROE for purposes of calculating both the NCCR tariff and AFUDC will likewise be 95 basis points lower than the revised ROE rate setting point. If Plant Vogtle Units 3 and 4 are not placed in service by December 31, 2020, then (i) the ROE for purposes of calculating the NCCR tariff will be reduced an additional 300 basis points, or $8 million per month, and may, at the Georgia PSC's discretion, be accrued to be used for the benefit of customers, until such time as the units are placed in service and (ii) the ROE used to calculate AFUDC will be Georgia Power's average cost of long-term debt.

Under the terms of the Vogtle Cost Settlement Agreement, Plant Vogtle Units 3 and 4 will be placed into retail rate base on December 31, 2020 or when placed in service, whichever is later. The Georgia PSC will determine for retail ratemaking purposes the process of transitioning Plant Vogtle Units 3 and 4 from a construction project to an operating plant no later than Georgia Power's base rate case required to be filed by July 1, 2019.

As of December 31, 2016, Georgia Power had borrowed $2.6 billion related to Plant Vogtle Units 3 and 4 costs through a loan guarantee agreement between Georgia Power and the DOE and a multi-advance credit facility among Georgia Power, the DOE, and the FFB. See Note 6 to the financial statements of Southern Company and Georgia Power under "DOE Loan Guarantee Borrowings" in Item 8 herein for additional information, including applicable covenants, events of default, and mandatory prepayment events.

Processes are in place that are designed to assure compliance with the requirements specified in the Westinghouse Design Control Document for the AP1000 nuclear reactor and the combined construction and operating licenses, including inspections by Southern Nuclear and the NRC that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the NRC. Various design and other licensing-based compliance matters, including the timely resolution of Inspections, Tests, Analyses, and Acceptance Criteria and the related approvals by the NRC, may arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs either to the Vogtle Owners or the Contractor or to both.

In addition to Toshiba's reaffirmation of its commitment, the Contractor provided Georgia Power with revised forecasted in-service dates of December 2019 and September 2020 for Plant Vogtle Units 3 and 4, respectively. Georgia Power is currently reviewing a preliminary summary schedule supporting these dates that ultimately must be reconciled to a detailed integrated project schedule. As construction continues, the risk remains that challenges with Contractor performance including labor productivity, fabrication, delivery, assembly, and installation of plant systems, structures, and components, or other issues could arise and may further impact project schedule and cost. Georgia Power expects the Contractor to employ mitigation efforts and believes the Contractor is responsible for any related costs under the Vogtle 3 and 4 Agreement. Georgia Power estimates its financing costs for Plant Vogtle Units 3 and 4 to be approximately $30 million per month, with total construction period financing costs of approximately $2.5 billion. Additionally, Georgia Power estimates its owner's costs to be approximately $6 million per month, net of delay liquidated damages.

The revised forecasted in-service dates are within the timeframe contemplated in the Vogtle Cost Settlement Agreement and would enable both units to qualify for PTCs the Internal Revenue Service has allocated to each of Plant Vogtle Units 3 and 4, which require the applicable unit to be placed in service before 2021. The net present value of the PTCs is estimated at approximately $400 million per unit.

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

See Note 3 to the financial statements of Southern Company under "Regulatory Matters - Georgia Power - Nuclear Construction" and of Georgia Power under "Retail Regulatory Matters - Nuclear Construction" for additional information regarding Plant Vogtle Units 3 and 4.

Kemper IGCC construction and rate recovery

Mississippi Power continues to progress toward completing the construction and start-up of the Kemper IGCC, which was approved by the Mississippi PSC in the 2010 certificate of public convenience and necessity (CPCN) proceedings, subject to a construction cost cap of $2.88 billion, net of $245 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (Initial DOE Grants) and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, AFUDC, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when Mississippi Power demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on customers relative to the original proposal for the CPCN) (Cost Cap Exceptions). The current cost estimate for the Kemper IGCC in total is approximately $6.99 billion, which includes approximately $5.64 billion of costs subject to the construction cost cap and is net of the $137 million in additional grants from the DOE received on April 8, 2016 (Additional DOE Grants), which are expected to be used to reduce future rate impacts to customers. Mississippi Power does not intend to seek any rate recovery for any related costs that exceed the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions. Through December 31, 2016, in the aggregate, Southern Company and Mississippi Power have incurred charges of $2.76 billion ($1.71 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC. The current cost estimate includes costs through March 15, 2017.

In addition to the current construction cost estimate, Mississippi Power is identifying potential improvement projects that ultimately may be completed subsequent to placing the remainder of the Kemper IGCC in service. If completed, such improvement projects would be expected to enhance plant performance, safety, and/or operations. As of December 31, 2016, approximately $12 million of related potential costs has been included in the estimated loss on the Kemper IGCC. Other projects have yet to be fully evaluated, have not been included in the current cost estimate, and may be subject to the $2.88 billion cost cap. Any further changes in the estimated costs of the Kemper IGCC subject to the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions, will be reflected in Southern Company's and Mississippi Power's statements of income and these changes could be material.

The expected completion date of the Kemper IGCC at the time of the Mississippi PSC's approval in 2010 was May 2014. The combined cycle and the associated common facilities portion of the Kemper IGCC were placed in service in August 2014. The remainder of the plant, including the gasifiers and the gas clean-up facilities, represents first-of-a-kind technology. The initial production of syngas began on July 14, 2016 for gasifier "B" and on September 13, 2016 for gasifier "A." Mississippi Power achieved integrated operation of both gasifiers on January 29, 2017, including the production of electricity from syngas in both combustion turbines. Mississippi Power subsequently completed a brief outage to repair and make modifications to further improve the plant's ability to achieve sustained operations sufficient to support placing the plant in service for customers. Efforts to reach sustained operation of both gasifiers and production of electricity from syngas in both combustion turbines are in process. The plant has produced and captured CO_2, and has produced sulfuric acid and ammonia, all of acceptable quality under the related off-take agreements. On February 20, 2017, Mississippi Power determined gasifier "B," which has been producing syngas over 60% of the time since early November 2016, requires an outage to remove ash deposits from its ash removal system. Gasifier "A" and combustion turbine "A" are expected to remain in operation, producing electricity from syngas, as well as producing chemical by-products. As a result, Mississippi Power currently expects the remainder of the Kemper IGCC, including both gasifiers, will be placed in service by mid-March 2017.

Any extension of the in-service date beyond mid-March 2017 is currently estimated to result in additional base costs of approximately $25 million to $35 million per month, which includes maintaining necessary levels of start-up labor, materials, and fuel, as well as operational resources required to execute start-up and commissioning activities. Additional costs may be required for remediation of any further equipment and/or design issues identified. Any extension of the in-service date with respect to the Kemper IGCC beyond mid-March 2017 would also increase costs for the Cost Cap Exceptions, which are not subject to the $2.88 billion cost cap established by the Mississippi PSC. These costs include AFUDC, which is currently estimated to total approximately $16 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting and legal fees of approximately $3 million per month. Further cost increases and/or extensions of the expected in-service date may result from factors including, but not limited to, difficulties integrating the systems required for sustained operations, sustaining nitrogen supply, major equipment failure, unforeseen engineering or design problems including any repairs and/or modifications to systems, and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC).

Upon placing the remainder of the plant in service, Mississippi Power will be primarily focused on completing the regulatory cost recovery process. In December 2015, the Mississippi PSC issued an order, based on a stipulation between Mississippi Power and the Mississippi Public Utilities Staff (MPUS), authorizing rates that provide for the recovery of approximately $126 million annually related to Kemper IGCC assets previously placed in service.

On August 17, 2016, the Mississippi PSC established a discovery docket to manage all filings related to Kemper IGCC prudence issues. On October 3, 2016 and November 17, 2016, Mississippi Power made filings in this docket including a review and explanation of differences between the Kemper IGCC project estimate set forth in the 2010 CPCN proceedings and the most recent Kemper IGCC project estimate, as well as comparisons of current cost estimates and current expected plant operational parameters to the estimates presented in the 2010 CPCN proceedings for the first five years after the Kemper IGCC is placed in service. Compared to amounts presented in the 2010 CPCN proceedings, operations and maintenance expenses have increased an average of $105 million annually and maintenance capital has increased an average of $44 million annually for the first full five years of operations for the Kemper IGCC. Additionally, while the current estimated operational availability estimates reflect ultimate results similar to those presented in the 2010 CPCN proceedings, the ramp up period for the current estimates reflects a lower starting point and a slower escalation rate.

In the fourth quarter 2016, as a part of the Integrated Resource Plan process, the Southern Company system completed its regular annual updated fuel forecast, the 2017 Annual Fuel Forecast. This updated fuel forecast reflected significantly lower long-term estimated costs for natural gas than were previously projected. As a result of the updated long-term natural gas forecast, as well as the revised operating expense projections reflected in the discovery docket filings, on February 21, 2017, Mississippi Power filed an updated project economic viability analysis of the Kemper IGCC as required under the Mississippi PSC's April 2012 order confirming authorization of the Kemper IGCC. The project economic viability analysis measures the life cycle economics of the Kemper IGCC compared to feasible alternatives, natural gas combined cycle generating units, under a variety of scenarios and considering fuel, operating and capital costs, and operating characteristics, as well as federal and state taxes and incentives. The reduction in the projected long-term natural gas prices in the 2017 Annual Fuel Forecast and, to a lesser extent, the increase in the estimated Kemper IGCC operating costs, negatively impact the updated project economic viability analysis.

After the remainder of the plant is placed in service, AFUDC equity of approximately $11 million per month will no longer be recorded in income, and Mississippi Power expects to incur approximately $25 million per month in depreciation, taxes, operations and maintenance expenses, interest expense, and regulatory costs in excess of current rates. Mississippi Power expects to file a request for authority from the Mississippi PSC and the FERC to defer all Kemper IGCC costs incurred after the in-service date that cannot be capitalized, are not included in current rates, and are not required to be charged against earnings as a result of the $2.88 billion cost cap until such time as the Mississippi PSC completes its review and includes the resulting allowable costs in rates. In the event that the Mississippi PSC does not grant Mississippi Power's request for an accounting order, these monthly expenses will be charged to income as incurred and will not be recoverable through rates. The ultimate outcome of this matter cannot now be determined but could have a material impact on Southern Company's and Mississippi Power's result of operations, financial condition, and liquidity.

Mississippi Power is required to file a rate case to address Kemper IGCC cost recovery by June 3, 2017 (2017 Rate Case). Costs incurred through December 31, 2016 totaled $6.73 billion, net of the Initial and Additional DOE Grants. Of this total, $2.76 billion of costs has been recognized through income as a result of the $2.88 billion cost cap, $0.84 billion is included in retail and wholesale rates for the assets in service, and the remainder will be the subject of the 2017 Rate Case to be filed with the Mississippi PSC and expected subsequent wholesale Municipal and Rural Associations rate filing with the FERC. Mississippi Power continues to believe that all costs related to the Kemper IGCC have been prudently incurred in accordance with the requirements of the 2012 MPSC order confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing the acquisition, construction, and operation of the Kemper IGCC. Mississippi Power also recognizes significant areas of potential challenge during future regulatory proceedings (and any subsequent, related legal challenges) exist. As described further herein, these challenges include, but are not limited to, prudence issues associated with capital costs, financing costs (AFUDC), and future operating costs, net of chemical revenues; potential operating parameters; income tax issues; costs deferred as regulatory assets; and the 15% portion of the project previously contracted to SMEPA.

Although the 2017 Rate Case has not yet been filed and is subject to future developments with either the Kemper IGCC or the Mississippi PSC, consistent with its approach in the 2013 and 2015 rate proceedings in accordance with the law passed in 2013 authorizing multi-year rate plans, Mississippi Power is developing both a traditional rate case requesting full cost recovery of the $3.31 billion (net of $137 million in additional DOE Grants) not currently in rates and a rate mitigation plan that together represent Mississippi Power's probable filing strategy. Mississippi Power also expects that timely resolution of the 2017 Rate Case will likely require a negotiated settlement agreement. In the event an agreement acceptable to both Mississippi Power and the MPUS (and other parties) can be negotiated and ultimately approved by the Mississippi PSC, it is reasonably possible that full regulatory recovery of all Kemper IGCC costs will not occur. The impact of such an agreement on Southern Company's and Mississippi Power's financial statements would depend on the method, amount, and type of cost recovery ultimately excluded. Certain costs, including operating costs, would be recorded to income in the period incurred, while other costs, including investment-related costs, would be charged to income when it is probable they will not be recovered and the amounts can be reasonably estimated. In the event an agreement acceptable to the parties cannot be reached, Mississippi Power intends to fully litigate its request for full recovery through the Mississippi PSC regulatory process and any subsequent legal challenges.

Mississippi Power has evaluated various scenarios in connection with its processes to prepare the 2017 Rate Case and Southern Company and Mississippi Power have recognized an additional $80 million charge to income, which is the estimated minimum probable amount of the $3.31 billion of Kemper IGCC costs not currently in rates that would not be recovered under the probable rate mitigation plan to be filed by June 3, 2017. Given the variety of potential scenarios and the uncertainty of the outcome of future regulatory proceedings with the Mississippi PSC (and any subsequent related legal challenges), the ultimate

outcome of these matters cannot now be determined but could result in further charges that could have a material impact on Southern Company’s and Mississippi Power’s results of operations, financial condition, and liquidity.
Southern Company and Mississippi Power are defendants in various lawsuits that allege improper disclosure about the Kemper IGCC. While Southern Company and Mississippi Power believe that these lawsuits are without merit, an adverse outcome could have a material impact on Southern Company’s and Mississippi Power's results of operations, financial condition, and liquidity. In addition, the SEC is conducting a formal investigation of Southern Company and Mississippi Power concerning the estimated costs and expected in-service date of the Kemper IGCC. Southern Company and Mississippi Power believe the investigation is focused primarily on periods subsequent to 2010 and on accounting matters, disclosure controls and procedures, and internal controls over financial reporting associated with the Kemper IGCC.
The ultimate outcome of these matters, including the resolution of legal challenges, determinations of prudency, and the specific manner of recovery of prudently-incurred costs, is subject to further regulatory actions and cannot be determined at this time.
See Note 3 to the financial statements of Southern Company and Mississippi Power under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.
Southern Company Gas' significant investments in pipelines and pipeline development projects involve financial and execution risks.
Southern Company Gas has made significant investments in existing pipelines and pipeline development projects. Many of the existing pipelines are, and when completed many of the pipeline development projects will be, operated by third parties. If one of these agents fails to perform in a proper manner, the value of the investment could decline and Southern Company Gas could lose part or all of the investment. In addition, from time to time, Southern Company Gas may be required to contribute additional capital to a pipeline joint venture or guarantee the obligations of such joint venture.
With respect to certain pipeline development projects, Southern Company Gas will rely on its joint venture partners for construction management and will not exercise direct control over the process. All of the pipeline development projects are dependent on contractors for the successful and timely completion of the projects. Further, the development of pipeline projects involves numerous regulatory, environmental, construction, safety, political, and legal uncertainties and may require the expenditure of significant amounts of capital. These projects may not be completed on schedule, at the budgeted cost, or at all. There may be cost overruns and construction difficulties that cause Southern Company Gas' capital expenditures to exceed its initial expectations. Moreover, Southern Company Gas' revenues will not increase immediately upon the expenditure of funds on a pipeline project. Pipeline construction occurs over an extended period of time and Southern Company Gas will not receive material increases in revenues until the project is placed in service.
The occurrence of any of the foregoing events could adversely affect the results of operations, cash flows, and financial condition of Southern Company Gas and Southern Company.
FINANCIAL, ECONOMIC, AND MARKET RISKS
The electric generation and energy marketing operations of the traditional electric operating companies and Southern Power and the natural gas operations of Southern Company Gas are subject to risks, many of which are beyond their control, including changes in energy prices and fuel costs, which may reduce Southern Company's, the traditional electric operating companies', Southern Power's, and/or Southern Company Gas' revenues and increase costs.
The generation, energy marketing, and natural gas operations of the Southern Company system are subject to changes in energy prices and fuel costs, which could increase the cost of producing power, decrease the amount received from the sale of energy, and/or make electric generating facilities less competitive. The market prices for these commodities may fluctuate significantly over relatively short periods of time. Among the factors that could influence energy prices and fuel costs are:
- prevailing market prices for coal, natural gas, uranium, fuel oil, biomass, and other fuels, as applicable, used in the generation facilities of the traditional electric operating companies and Southern Power and, in the case of natural gas, distributed by Southern Company Gas, including associated transportation costs, and supplies of such commodities;
- demand for energy and the extent of additional supplies of energy available from current or new competitors;

- liquidity in the general wholesale electricity and natural gas markets;
- weather conditions impacting demand for electricity and natural gas;
- seasonality;
- transmission or transportation constraints, disruptions, or inefficiencies;
- availability of competitively priced alternative energy sources;
- forced or unscheduled plant outages for the Southern Company system, its competitors, or third party providers;
- the financial condition of market participants;

- the economy in the Southern Company system's service territory, the nation, and worldwide, including the impact of economic conditions on demand for electricity and the demand for fuels, including natural gas;
- natural disasters, wars, embargos, acts of terrorism, and other catastrophic events; and
- federal, state, and foreign energy and environmental regulation and legislation.

Certain of these factors could increase the expenses of the traditional electric operating companies, Southern Power, or Southern Company Gas and Southern Company. For the traditional electric operating companies and Southern Company Gas' regulated gas distribution operations, such increases may not be fully recoverable through rates. Other of these factors could reduce the revenues of the traditional electric operating companies, Southern Power, or Southern Company Gas and Southern Company.

Historically, the traditional electric operating companies and Southern Company Gas from time to time have experienced underrecovered fuel and/or purchased gas cost balances and may experience such balances in the future. While the traditional electric operating companies and Southern Company Gas are generally authorized to recover fuel and/or purchased gas costs through cost recovery clauses, recovery may be denied if costs are deemed to be imprudently incurred, and delays in the authorization of such recovery could negatively impact the cash flows of the affected traditional electric operating company or Southern Company Gas and Southern Company.

Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas are subject to risks associated with a changing economic environment, customer behaviors, including increased energy conservation, and adoption patterns of technologies by the customers of the traditional electric operating companies, Southern Power, and Southern Company Gas.

The consumption and use of energy are fundamentally linked to economic activity. This relationship is affected over time by changes in the economy, customer behaviors, and technologies. Any economic downturn could negatively impact customer growth and usage per customer, thus reducing the sales of energy and revenues. Additionally, any economic downturn or disruption of financial markets, both nationally and internationally, could negatively affect the financial stability of customers and counterparties of the traditional electric operating companies, Southern Power, and Southern Company Gas.

Outside of economic disruptions, changes in customer behaviors in response to energy efficiency programs, changing conditions and preferences, or changes in the adoption of technologies could affect the relationship of economic activity to the consumption of energy.

Both federal and state programs exist to influence how customers use energy, and several of the traditional electric operating companies and Southern Company Gas have PSC or other applicable state regulatory agency mandates to promote energy efficiency. Conservation programs could impact the financial results of Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas in different ways. For example, if any traditional electric operating company or Southern Company Gas is required to invest in conservation measures that result in reduced sales from effective conservation, regulatory lag in adjusting rates for the impact of these measures could have a negative financial impact on such traditional electric operating company or Southern Company Gas and Southern Company. Customers could also voluntarily reduce their consumption of energy in response to decreases in their disposable income, increases in energy prices, or individual conservation efforts.

In addition, the adoption of technology by customers can have both positive and negative impacts on sales. Many new technologies utilize less energy than in the past. However, new electric and natural gas technologies such as electric and natural gas vehicles can create additional demand. The Southern Company system uses best available methods and experience to incorporate the effects of changes in customer behavior, state and federal programs, PSC or other applicable state regulatory agency mandates, and technology, but the Southern Company system's planning processes may not appropriately estimate and incorporate these effects.

All of the factors discussed above could adversely affect Southern Company's, the traditional electric operating companies', Southern Power's, and/or Southern Company Gas' results of operations, financial condition, and liquidity.

The operating results of Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas are affected by weather conditions and may fluctuate on a seasonal and quarterly basis. In addition, significant weather events, such as hurricanes, tornadoes, floods, droughts, and winter storms, could result in substantial damage to or limit the operation of the properties of the traditional electric operating companies, Southern

Power, and/or Southern Company Gas and could negatively impact results of operation, financial condition, and liquidity.

Electric power and natural gas supply are generally seasonal businesses. In many parts of the country, demand for power peaks during the summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter months. In most of the areas the traditional electric operating companies serve, electric power sales peak during the summer, while in most of the areas Southern Company Gas serves, natural gas demand peaks during the winter. As a result, the overall operating results of Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas may fluctuate substantially on a seasonal basis. In addition, the traditional electric operating companies, Southern Power, and Southern Company Gas have historically sold less power and natural gas when weather conditions are milder. Unusually mild weather in the future could reduce the revenues, net income, and available cash of Southern Company, the traditional electric operating companies, Southern Power, and/or Southern Company Gas.

In addition, volatile or significant weather events could result in substantial damage to the transmission and distribution lines of the traditional electric operating companies, the generating facilities of the traditional electric operating companies and Southern Power, and the natural gas distribution and storage facilities of Southern Company Gas. The traditional electric operating companies, Southern Power, and Southern Company Gas have significant investments in the Atlantic and Gulf Coast regions and Southern Power has wind and natural gas investments in various states, including Maine, Minnesota, Oklahoma, and Texas, which could be subject to severe weather, as well as solar investments in various states, including California, which could be subject to natural disasters. Further, severe drought conditions can reduce the availability of water and restrict or prevent the operation of certain generating facilities.

In the event a traditional electric operating company or Southern Company Gas experiences any of these weather events or any natural disaster or other catastrophic event, recovery of costs in excess of reserves and insurance coverage is subject to the approval of its state PSC or other applicable state regulatory agency. Historically, the traditional electric operating companies from time to time have experienced deficits in their storm cost recovery reserve balances and may experience such deficits in the future. Any denial by the applicable state PSC or other applicable state regulatory agency or delay in recovery of any portion of such costs could have a material negative impact on a traditional electric operating company's or Southern Company Gas' and Southern Company's results of operations, financial condition, and liquidity.

In addition, damages resulting from significant weather events within the service territory of any traditional electric operating company or Southern Company Gas or affecting Southern Power's customers may result in the loss of customers and reduced demand for energy for extended periods. Any significant loss of customers or reduction in demand for energy could have a material negative impact on a traditional electric operating company's, Southern Power's, or Southern Company Gas' and Southern Company's results of operations, financial condition, and liquidity.

Acquisitions, dispositions, or other strategic ventures or investments may not result in anticipated benefits and may present risks not originally contemplated, which may have a material adverse effect on the liquidity, results of operations, and financial condition of Southern Company and its subsidiaries.

Southern Company and its subsidiaries have made significant acquisitions and investments in the past and may in the future make additional acquisitions, dispositions, or other strategic ventures or investments. Southern Company and its subsidiaries continually seek opportunities to create value through various transactions, including acquisitions or sales of assets.

Southern Company and its subsidiaries may face significant competition for transactional opportunities and anticipated transactions may not be completed on acceptable terms or at all. In addition, these transactions are intended to, but may not, result in the generation of cash or income, the realization of savings, the creation of efficiencies, or the reduction of risk. These transactions may also affect the liquidity, results of operations, and financial condition of Southern Company and its subsidiaries.

These transactions also involve risks, including:

- they may not result in an increase in income or provide an adequate return on capital or other anticipated benefits;
- they may result in Southern Company or its subsidiaries entering into new or additional lines of business, which may have new or different business or operational risks;
- they may not be successfully integrated into the acquiring company's operations and/or internal control processes;
- the due diligence conducted prior to a transaction may not uncover situations that could result in financial or legal exposure or the acquiring company may not appropriately evaluate the likelihood or quantify the exposure from identified risks;

- they may result in decreased earnings, revenues, or cash flow;
- expected benefits of a transaction may be dependent on the cooperation or performance of a counterparty; or
- for the traditional electric operating companies, costs associated with such investments that were expected to be recovered through rates may not be recoverable.

Southern Company and Southern Company Gas are holding companies and are dependent on cash flows from their respective subsidiaries to meet their ongoing and future financial obligations, including making interest and principal payments on outstanding indebtedness and, for Southern Company, to pay dividends on its common stock.

Southern Company and Southern Company Gas are holding companies and, as such, they have no operations of their own. Substantially all of Southern Company's and Southern Company Gas' respective consolidated assets are held by subsidiaries. A significant portion of Southern Company Gas' debt is issued by its 100%-owned subsidiary, Southern Company Gas Capital, and is fully and unconditionally guaranteed by Southern Company Gas. Southern Company's and Southern Company Gas' ability to meet their respective financial obligations, including making interest and principal payments on outstanding indebtedness, and, for Southern Company, to pay dividends on its common stock, is primarily dependent on the net income and cash flows of their respective subsidiaries and the ability of those subsidiaries to pay upstream dividends or to repay borrowed funds. Prior to funding Southern Company or Southern Company Gas, the respective subsidiaries have regulatory restrictions and financial obligations that must be satisfied, including among others, debt service and preferred and preference stock dividends. These subsidiaries are separate legal entities and have no obligation to provide Southern Company or Southern Company Gas with funds. In addition, Southern Company and Southern Company Gas may provide capital contributions or debt financing to subsidiaries under certain circumstances, which would reduce the funds available to meet their respective financial obligations, including making interest and principal payments on outstanding indebtedness, and to pay dividends on Southern Company's common stock.

A downgrade in the credit ratings of Southern Company, any of the traditional electric operating companies, Southern Power, Southern Company Gas, Southern Company Gas Capital, or Nicor Gas could negatively affect their ability to access capital at reasonable costs and/or could require Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas, Southern Company Gas Capital, or Nicor Gas to post collateral or replace certain indebtedness.

There are a number of factors that rating agencies evaluate to arrive at credit ratings for Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas, Southern Company Gas Capital, and Nicor Gas, including capital structure, regulatory environment, the ability to cover liquidity requirements, and other commitments for capital. Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas, Southern Company Gas Capital, and Nicor Gas could experience a downgrade in their ratings if any rating agency concludes that the level of business or financial risk of the industry or Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas, Southern Company Gas Capital, or Nicor Gas has deteriorated. Changes in ratings methodologies by the agencies could also have a negative impact on credit ratings. If one or more rating agencies downgrade Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas, Southern Company Gas Capital, or Nicor Gas, borrowing costs likely would increase, including automatic increases in interest rates under applicable term loans and credit facilities, the pool of investors and funding sources would likely decrease, and, particularly for any downgrade to below investment grade, significant collateral requirements may be triggered in a number of contracts. Any credit rating downgrades could require a traditional electric operating company, Southern Power, Southern Company Gas, Southern Company Gas Capital, or Nicor Gas to alter the mix of debt financing currently used, and could require the issuance of secured indebtedness and/or indebtedness with additional restrictive covenants.

Uncertainty in demand for energy can result in lower earnings or higher costs. If demand for energy falls short of expectations, it could result in potentially stranded assets. If demand for energy exceeds expectations, it could result in increased costs for purchasing capacity in the open market or building additional electric generation and transmission facilities or natural gas distribution and storage facilities.

Southern Company, the traditional electric operating companies, and Southern Power each engage in a long-term planning process to estimate the optimal mix and timing of new generation assets required to serve future load obligations. Southern Company Gas engages in a long-term planning process to estimate the optimal mix and timing of building new pipelines and storage facilities, replacing existing pipelines, rewatering storage facilities, and entering new markets and/or expanding in existing markets. These planning processes must look many years into the future in order to accommodate the long lead times associated with the permitting and construction of new generation and associated transmission facilities and natural gas distribution and storage facilities. Inherent risk exists in predicting demand this far into the future as these future loads are dependent on many uncertain factors, including economic conditions, customer usage patterns, efficiency programs, and customer technology adoption. Because regulators may not permit the traditional electric operating companies or Southern Company Gas' regulated operating companies to adjust rates to recover the costs of new generation and associated transmission assets and/or new pipelines and related infrastructure in a timely manner or at all, Southern Company and its subsidiaries may not be able to fully recover these costs or may have exposure to regulatory lag associated with the time between the incurrence of costs and the recovery in customers' rates. In addition, under Southern Power's model of selling capacity and energy at negotiated market-based rates under long-term PPAs, Southern Power might not be able to fully execute its business plan if market prices drop below original forecasts. Southern Power and/or the traditional electric operating companies may not be able to extend existing PPAs or find new buyers for existing generation assets as existing PPAs expire, or they may be forced to market these assets at prices lower than originally intended. These situations could have negative impacts on net income and cash flows for the affected traditional electric operating company, Southern Power, or Southern Company Gas, and for Southern Company.

The traditional electric operating companies are currently obligated to supply power to retail customers and wholesale customers under long-term PPAs. Southern Power is currently obligated to supply power to wholesale customers under long-term PPAs. At peak times, the demand for power required to meet this obligation could exceed the Southern Company system's available generation capacity. Market or competitive forces may require that the traditional electric operating companies or Southern Power purchase capacity on the open market or build additional generation and transmission facilities. Because regulators may not permit the traditional electric operating companies to pass all of these purchase or construction costs on to their customers, the traditional electric operating companies may not be able to recover some or all of these costs or may have exposure to regulatory lag associated with the time between the incurrence of costs of purchased or constructed capacity and the traditional electric operating companies' recovery in customers' rates. Under Southern Power's long-term fixed price PPAs, Southern Power would not have the ability to recover any of these costs. These situations could have negative impacts on net income and cash flows for the affected traditional electric operating company or Southern Power, and for Southern Company.

The businesses of Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas, and Nicor Gas are dependent on their ability to successfully access funds through capital markets and financial institutions. The inability of Southern Company, any traditional electric operating company, Southern Power, Southern Company Gas, or Nicor Gas to access funds may limit its ability to execute its business plan by impacting its ability to fund capital investments or acquisitions that Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas, or Nicor Gas may otherwise rely on to achieve future earnings and cash flows.

Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas, and Nicor Gas rely on access to both short-term money markets and longer-term capital markets as a significant source of liquidity for capital requirements not satisfied by the cash flow from their respective operations. If Southern Company, any traditional electric operating company, Southern Power, Southern Company Gas, or Nicor Gas is not able to access capital at competitive rates or on favorable terms, its ability to implement its business plan will be limited by impacting its ability to fund capital investments or acquisitions that Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas, or Nicor Gas may otherwise rely on to achieve future earnings and cash flows. In addition, Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas, and Nicor Gas rely on committed bank lending agreements as back-up liquidity which allows them to access low cost money markets. Each of Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas, and Nicor Gas believes that it will maintain sufficient access to these financial markets based upon current credit ratings. However, certain events or market disruptions may increase the cost of borrowing or adversely affect the ability to raise capital through the issuance of securities or other borrowing arrangements or the ability to secure committed bank lending agreements used as back-up sources of capital. Such disruptions could include:

- an economic downturn or uncertainty;
- bankruptcy or financial distress at an unrelated energy company, financial institution, or sovereign entity;
- capital markets volatility and disruption, either nationally or internationally;
- changes in tax policy;
- volatility in market prices for electricity and natural gas;
- terrorist attacks or threatened attacks on the Southern Company system's facilities or unrelated energy companies' facilities;
- war or threat of war; or
- the overall health of the utility and financial institution industries.

As of December 31, 2016, Mississippi Power's current liabilities exceeded current assets by approximately $371 million primarily due to $551 million in promissory notes to Southern Company which mature in December 2017, $35 million in senior notes which mature in November 2017, and $63 million in short-term debt. Mississippi Power expects the funds needed to satisfy the promissory notes to Southern Company will exceed amounts available from operating cash flows, lines of credit, and other external sources. Accordingly, Mississippi Power intends to satisfy these obligations through loans and/or equity contributions from Southern Company. Specifically, Mississippi Power has been informed by Southern Company that, in the event sufficient funds are not available from external sources, Southern Company intends to (i) extend the maturity of the $551 million in promissory notes and (ii) provide Mississippi Power with loans and/or equity contributions sufficient to fund the remaining indebtedness scheduled to mature and other cash needs over the next 12 months.

Georgia Power's ability to make future borrowings through its term loan credit facility with the Federal Financing Bank is subject to the satisfaction of customary conditions, as well as certification of compliance with the requirements of the loan guarantee program under Title XVII of the Energy Policy Act of 2005, including accuracy of project-related representations and warranties, delivery of updated project-related information and evidence of compliance with the prevailing wage requirements of the Davis-Bacon Act of 1931, as amended, and certification from the DOE's consulting engineer that proceeds of the advances are used to reimburse certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the Title XVII Loan Guarantee Program.

Volatility in the securities markets, interest rates, and other factors could substantially increase defined benefit pension and other postretirement plan costs and the costs of nuclear decommissioning.

The costs of providing pension and other postretirement benefit plans are dependent on a number of factors, such as the rates of return on plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plan, changes in actuarial assumptions, future government regulation, changes in life expectancy, and the frequency and amount of the Southern Company system's required or voluntary contributions made to the plans. Changes in actuarial assumptions and differences between the assumptions and actual values, as well as a significant decline in the value of investments that fund the pension and other postretirement plans, if not offset or mitigated by a decline in plan liabilities, could increase pension and other postretirement expense, and the Southern Company system could be required from time to time to fund the pension plans with significant amounts of cash. Such cash funding obligations could have a material impact on liquidity by reducing cash flows and could negatively affect results of operations. Additionally, Alabama Power and Georgia Power each hold significant assets in their nuclear decommissioning trusts to satisfy obligations to decommission Alabama Power's and Georgia Power's nuclear plants. The rate of return on assets held in those trusts can significantly impact both the costs of decommissioning and the funding requirements for the trusts.

Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas are subject to risks associated with their ability to obtain adequate insurance at acceptable costs.

The financial condition of some insurance companies, the threat of terrorism, and natural disasters, among other things, could have disruptive effects on insurance markets. The availability of insurance covering risks that Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas, and their respective competitors typically insure against may decrease, and the insurance that Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas are able to obtain may have higher deductibles, higher premiums, and more restrictive policy terms. Further, the insurance policies maintained by Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas may not cover all of the potential exposures or the actual amount of loss incurred.

Any losses not covered by insurance, or any increases in the cost of applicable insurance, could adversely affect the results of operations, cash flows, or financial condition of Southern Company, the traditional electric operating companies, Southern Power, or Southern Company Gas.

The use of derivative contracts by Southern Company and its subsidiaries in the normal course of business could result in financial losses that negatively impact the net income of Southern Company and its subsidiaries or in reported net income volatility.

Southern Company and its subsidiaries, including the traditional electric operating companies, Southern Power, and Southern Company Gas, use derivative instruments, such as swaps, options, futures, and forwards, to manage their commodity and interest rate exposures and, to a lesser extent, manage foreign currency exchange rate exposure and engage in limited trading activities. Southern Company and its subsidiaries could recognize financial losses as a result of volatility in the market values of these contracts or if a counterparty fails to perform. These risks are managed through risk management policies, limits, and procedures. These risk management policies, limits, and procedures might not work as planned and cannot entirely eliminate the risks associated with these activities. In addition, derivative contracts entered into for hedging purposes might not off-set the underlying exposure being hedged as expected, resulting in financial losses. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management's judgment or use of estimates. The factors used in the valuation of these instruments become more difficult to predict and the calculations become less reliable the further into the future these estimates are made. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

In addition, Southern Company Gas utilizes derivative instruments to lock in economic value in wholesale gas services, which may not qualify or are not designated as hedges for accounting purposes. The difference in accounting treatment for the underlying position and the financial instrument used to hedge the value of the contract can cause volatility in reported net income of Southern Company and Southern Company Gas while the positions are open due to mark-to-market accounting.

Future impairments of goodwill or long-lived assets could have a material adverse effect on Southern Company's and its subsidiaries' results of operations.

Goodwill is assessed for impairment at least annually and more frequently if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying value and long-lived assets are assessed for impairment whenever events or circumstances indicate that an asset's carrying amount may not be recoverable. In connection with the completion of the Merger, the application of the acquisition method of accounting was pushed down to Southern Company Gas. The excess of the purchase price over the fair values of Southern Company Gas' assets and liabilities was recorded as goodwill. This resulted in a significant increase in the goodwill recorded on Southern Company's and Southern Company Gas' consolidated balance sheets. In addition, Southern Company and its subsidiaries have long-lived assets recorded on their balance sheets. To the extent the value of goodwill or long-lived assets become impaired, Southern Company, Southern Company Gas, Southern Power, and the traditional electric operating companies may be required to incur impairment charges that could have a material impact on their results of operations.

Item 1B. UNRESOLVED STAFF COMMENTS.

None.

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Item 2. PROPERTIES
Electric
Electric Properties

The traditional electric operating companies, Southern Power, and SEGCO, at December 31, 2016, owned and/or operated 33 hydroelectric generating stations, 29 fossil fuel generating stations, three nuclear generating stations, 14 combined cycle/cogeneration stations, 33 solar facilities, seven wind facilities, one biomass facility, and one landfill gas facility. The amounts of capacity for each company, as of December 31, 2016, are shown in the table below.

Generating Station	Location	Nameplate Capacity (1) (KWs)	
FOSSIL STEAM			
Gadsden	Gadsden, AL	120,000	(2)
Gorgas	Jasper, AL	1,021,250	
Barry	Mobile, AL	1,300,000	(2)
Greene County	Demopolis, AL	300,000	(3)
Gaston Unit 5	Wilsonville, AL	880,000	
Miller	Birmingham, AL	2,532,288	(4)
Alabama Power Total		6,153,538	
Bowen	Cartersville, GA	3,160,000	
Hammond	Rome, GA	800,000	
McIntosh	Effingham County, GA	163,117	
Scherer	Macon, GA	750,924	(5)
Wansley	Carrollton, GA	925,550	(6)
Yates	Newnan, GA	700,000	
Georgia Power Total		6,499,591	
Crist	Pensacola, FL	970,000	
Daniel	Pascagoula, MS	500,000	(7)
Scherer Unit 3	Macon, GA	204,500	(5)
Gulf Power Total		1,674,500	
Daniel	Pascagoula, MS	500,000	(7)
Greene County	Demopolis, AL	200,000	(3)
Watson	Gulfport, MS	862,000	(8)
Mississippi Power Total		1,562,000	
Gaston Units 1-4	Wilsonville, AL		
SEGCO Total		1,000,000	(9)
Total Fossil Steam		16,889,629	
IGCC			
Kemper County/Ratcliffe	Kemper County, MS		(10)
Mississippi Power Total		622,906	

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Generating Station	Location	Nameplate Capacity (1)	
NUCLEAR STEAM			
Farley	Dothan, AL		
Alabama Power Total		1,720,000	
Hatch	Baxley, GA	899,612	(11)
Vogtle Units 1 and 2	Augusta, GA	1,060,240	(12)
Georgia Power Total		1,959,852	
Total Nuclear Steam		3,679,852	
COMBUSTION TURBINES			
Greene County	Demopolis, AL		
Alabama Power Total		720,000	
Boulevard	Savannah, GA	19,700	
McDonough Unit 3	Atlanta, GA	78,800	
McIntosh Units 1 through 8	Effingham County, GA	640,000	
McManus	Brunswick, GA	481,700	
Robins	Warner Robins, GA	158,400	
Wansley	Carrollton, GA	26,322	(6)
Wilson	Augusta, GA	354,100	
Georgia Power Total		1,759,022	
Lansing Smith Unit A	Panama City, FL	39,400	
Pea Ridge Units 1 through 3	Pea Ridge, FL	15,000	
Gulf Power Total		54,400	
Chevron Cogenerating Station	Pascagoula, MS	147,292	(13)
Sweatt	Meridian, MS	39,400	
Watson	Gulfport, MS	39,360	
Mississippi Power Total		226,052	
Addison	Thomaston, GA	668,800	
Cleveland County	Cleveland County, NC	720,000	
Dahlberg	Jackson County, GA	756,000	
Oleander	Cocoa, FL	791,301	
Rowan	Salisbury, NC	455,250	
Southern Power Total		3,391,351	
Gaston (SEGCO)	Wilsonville, AL	19,680	(9)
Total Combustion Turbines		6,170,505	
COGENERATION			
Washington County	Washington County, AL	123,428	
GE Plastics Project	Burkeville, AL	104,800	
Theodore	Theodore, AL	236,418	
Total Cogeneration		464,646	

Generating Station	Location	Nameplate Capacity (1)	
COMBINED CYCLE			
Barry	Mobile, AL		
Alabama Power Total		1,070,424	
McIntosh Units 10&11	Effingham County, GA	1,318,920	
McDonough-Atkinson Units 4 through 6	Atlanta, GA	2,520,000	
Georgia Power Total		3,838,920	
Smith	Lynn Haven, FL		
Gulf Power Total		545,500	
Daniel	Pascagoula, MS		
Mississippi Power Total		1,070,424	
Franklin	Smiths, AL	1,857,820	
Harris	Autaugaville, AL	1,318,920	
Mankato	Mankato, MN	375,000	
Rowan	Salisbury, NC	530,550	
Stanton Unit A	Orlando, FL	428,649	(14)
Wansley	Carrollton, GA	1,073,000	
Southern Power Total		5,583,939	
Total Combined Cycle		12,109,207	
HYDROELECTRIC FACILITIES			
Bankhead	Holt, AL	53,985	
Bouldin	Wetumpka, AL	225,000	
Harris	Wedowee, AL	132,000	
Henry	Ohatchee, AL	72,900	
Holt	Holt, AL	46,944	
Jordan	Wetumpka, AL	100,000	
Lay	Clanton, AL	177,000	
Lewis Smith	Jasper, AL	157,500	
Logan Martin	Vincent, AL	135,000	
Martin	Dadeville, AL	182,000	
Mitchell	Verbena, AL	170,000	
Thurlow	Tallassee, AL	81,000	
Weiss	Leesburg, AL	87,750	
Yates	Tallassee, AL	47,000	
Alabama Power Total		1,668,079	
Bartletts Ferry	Columbus, GA	173,000	
Goat Rock	Columbus, GA	38,600	
Lloyd Shoals	Jackson, GA	14,400	
Morgan Falls	Atlanta, GA	16,800	
North Highlands	Columbus, GA	29,600	
Oliver Dam	Columbus, GA	60,000	
Rocky Mountain	Rome, GA	215,256	(15)
Sinclair Dam	Milledgeville, GA	45,000	
Tallulah Falls	Clayton, GA	72,000	
Terrora	Clayton, GA	16,000	
Tugalo	Clayton, GA	45,000	
Wallace Dam	Eatonton, GA	321,300	
Yonah	Toccoa, GA	22,500	

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Generating Station	Location	Nameplate Capacity (1)	
6 Other Plants	Various Georgia locations	18,080	
Georgia Power Total		1,087,536	
Total Hydroelectric Facilities		2,755,615	
RENEWABLE SOURCES:			
SOLAR FACILITIES			
Fort Benning	Columbus, GA	30,000	
Fort Gordon	Augusta, GA	30,000	
Fort Stewart	Fort Stewart, GA	30,000	
Kings Bay	Camden County, GA	30,000	
Dalton	Dalton, GA	6,305	
3 Other Plants	Various Georgia locations	2,789	
Georgia Power Total		129,094	
Adobe	Kern County, CA	20,000	
Apex	North Las Vegas, NV	20,000	
Boulder I	Clark County, NV	100,000	
Butler	Taylor County, GA	103,700	
Butler Solar Farm	Taylor County, GA	22,000	
Calipatria	Imperial County, CA	20,000	
Campo Verde	Imperial County, CA	147,420	
Cimarron	Springer, NM	30,640	
Decatur County	Decatur County, GA	20,000	
Decatur Parkway	Decatur County, GA	84,000	
Desert Stateline	San Bernadino County, CA	299,900	(16)
Garland	Kern County, CA	205,130	
Granville	Oxford, NC	2,500	
Henrietta	Kings County, CA	102,000	
Imperial Valley	Imperial County, CA	163,200	
Lost Hills - Blackwell	Kern County, CA	33,440	
Macho Springs	Luna County, NM	55,000	
Morelos del Sol	Kern County, CA	15,000	
North Star	Fresno County, CA	61,600	
Pawpaw	Taylor County, GA	30,480	
Roserock	Pecos County, TX	160,000	
Rutherford	Rutherford County, NC	74,800	
Sandhills	Taylor County, GA	146,890	
Spectrum	Clark County, NV	30,240	
Tranquillity	Fresno County, CA	205,300	
Southern Power Total		2,153,240	(17)
Total Solar		2,282,334	
WIND FACILITIES			
Grant Plains	Grant County, OK	147,200	
Grant Wind	Grant County, OK	151,800	
Kay Wind	Kay County, OK	299,000	
Passadumkeag	Penobscot County, ME	42,900	
Salt Fork	Donley & Gray Counties TX	174,000	
Tyler Bluff	Cooke County, TX	125,580	
Wake Wind	Crosby & Floyd Counties, TX	257,250	(18)

Generating Station	Location	Nameplate Capacity (1)
Southern Power Total		1,197,730
LANDFILL GAS FACILITY		
Perdido	Escambia County, FL	
Gulf Power Total		3,200
BIOMASS FACILITY		
Nacogdoches	Sacul, TX	
Southern Power Total		115,500
Total Generating Capacity		46,291,124

Notes:

(1) See "Jointly-Owned Facilities" herein for additional information.

(2) In April 2015, as part of its environmental compliance strategy, Alabama Power ceased using coal at Gadsden Steam Plant and at Plant Barry Units 1 and 2 (250 MWs), but such units will remain available with natural gas as the fuel source. Alabama Power retired Plant Barry Unit 3 (225 MWs) in August 2015 and it is no longer available for generation.

(3) Owned by Alabama Power and Mississippi Power as tenants in common in the proportions of 60% and 40%, respectively. In April 2016, Alabama Power and Mississippi Power ceased using coal and began operating Units 1 and 2 solely on natural gas in June 2016 and July 2016, respectively. See Note 3 to the financial statements of Southern Company, Alabama Power, and Mississippi Power under "Regulatory Matters – Alabama Power – Environmental Accounting Order," "Retail Regulatory Matters – Environmental Accounting Order," and "Retail Regulatory Matters – Environmental Compliance Overview Plan," respectively, in Item 8 herein.

(4) Capacity shown is Alabama Power's portion (91.84%) of total plant capacity.

(5) Capacity shown for Georgia Power is 8.4% of Units 1 and 2 and 75% of Unit 3. Capacity shown for Gulf Power is 25% of Unit 3.

(6) Capacity shown is Georgia Power's portion (53.5%) of total plant capacity.

(7) Represents 50% of Plant Daniel Units 1 and 2, which are owned as tenants in common by Gulf Power and Mississippi Power.

(8) Mississippi Power ceased burning coal and other solid fuel at Plant Watson Units 4 and 5 (750 MWs) and began operating those units solely on natural gas in April 2015. Mississippi Power retired Plant Sweatt Units 1 and 2 (80 MWs) on July 31, 2016.

(9) SEGCO is jointly-owned by Alabama Power and Georgia Power. See BUSINESS in Item 1 herein for additional information.

(10) The capacity shown is the gross capacity using natural gas fuel without supplemental firing. The net capacity using lignite fuel with supplemental firing is expected to be 582 MWs. Mississippi Power placed the combined cycle and the associated common facilities portion of the Kemper IGCC in service using natural gas in 2014 and expects to place the remainder of the Kemper IGCC, including the gasifier and the gas clean-up facilities, in service by mid-March 2017.

(11) Capacity shown is Georgia Power's portion (50.1%) of total plant capacity.

(12) Capacity shown is Georgia Power's portion (45.7%) of total plant capacity.

(13) Generation is dedicated to a single industrial customer.

(14) Capacity shown is Southern Power's portion (65%) of total plant capacity.

(15) Capacity shown is Georgia Power's portion (25.4%) of total plant capacity. OPC operates the plant.

(16) 110 MWs were placed in service in the fourth quarter 2015 and 189 MWs were placed in service through July 2016, bringing the facility's total capacity to approximately 300 MWs.

(17) Southern Power total solar capacity shown is 100% of the nameplate capacity for each facility. When taking into consideration Southern Power's 90% equity interest in STR and various 66% and 51% equity interests in SRP's nine solar partnerships, Southern Power's equity portion of the total nameplate capacity

from all solar facilities is 1,505 MWs. See Note 2 to the financial statements of Southern Power in Item 8 herein and Note 12 to the financial statements of Southern Company under "Southern Power" in Item 8 herein for additional information.

(18) Southern Power owns 90.1%.

Except as discussed below under "Titles to Property," the principal plants and other important units of the traditional electric operating companies, Southern Power, and SEGCO are owned in fee by the respective companies. It is the opinion of

management of each such company that its operating properties are adequately maintained and are substantially in good operating condition, and suitable for their intended purpose.
Mississippi Power owns a 79-mile length of 500-kilovolt transmission line which is leased to Entergy Gulf States Louisiana, LLC. The line, completed in 1984, extends from Plant Daniel to the Louisiana state line. Entergy Gulf States Louisiana, LLC is paying a use fee over a 40-year period covering all expenses and the amortization of the original $57 million cost of the line. At December 31, 2016, the unamortized portion of this cost was approximately $16 million.
In conjunction with the Kemper IGCC, Mississippi Power owns a lignite mine and equipment and has acquired and will continue to acquire mineral reserves located around the Kemper IGCC site in Kemper County. The mine, operated by North American Coal Corporation, started commercial operation in 2013 with the capital cost of the mine and equipment totaling approximately $325 million as of December 31, 2016. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Lignite Mine and CO_2 Pipeline Facilities" of Mississippi Power in Item 7 herein and Note 3 to the financial statements of Southern Company and Mississippi Power under "Integrated Coal Gasification Combined Cycle – Lignite Mine and CO_2 Pipeline Facilities" in Item 8 herein for additional information on the lignite mine.
In 2016, the maximum demand on the traditional electric operating companies, Southern Power, and SEGCO was 35,781,000 KWs and occurred on July 25, 2016. The all-time maximum demand of 38,777,000 KWs on the traditional electric operating companies, Southern Power, and SEGCO occurred on August 22, 2007. These amounts exclude demand served by capacity retained by MEAG Power, OPC, and SEPA. The reserve margin for the traditional electric operating companies, Southern Power, and SEGCO in 2016 was 34.2%. See SELECTED FINANCIAL DATA in Item 6 herein for additional information.
Jointly-Owned Facilities
Alabama Power, Georgia Power, and Southern Power at December 31, 2016 had undivided interests in certain generating plants and other related facilities with non-affiliated parties. The percentages of ownership of the total plant or facility are as follows:

	Total Capacity (MWs)	Percentage Ownership Alabama Power	Power South	Georgia Power	OPC	MEAG Power	Dalton	Southern Power	OUC	FMPA	KUA
Plant Miller Units 1 and 2	1,320	91.8 %	8.2 %	— %	— %	— %	— %	— %	— %	— %	— %
Plant Hatch	1,796	—	—	50.1	30.0	17.7	2.2	—	—	—	—
Plant Vogtle Units 1 and 2	2,320	—	—	45.7	30.0	22.7	1.6	—	—	—	—
Plant Scherer Units 1 and 2	1,636	—	—	8.4	60.0	30.2	1.4	—	—	—	—
Plant Wansley	1,779	—	—	53.5	30.0	15.1	1.4	—	—	—	—
Rocky Mountain	848	—	—	25.4	74.6	—	—	—	—	—	—
Plant Stanton A	660	—	—	—	—	—	—	65.0	28.0	3.5	3.5

Alabama Power and Georgia Power have contracted to operate and maintain the respective units in which each has an interest (other than Rocky Mountain) as agent for the joint owners. SCS provides operation and maintenance services for Plant Stanton A. Southern Nuclear operates and provides services to Alabama Power's and Georgia Power's nuclear plants.
In addition, Georgia Power has commitments regarding a portion of a 5% interest in Plant Vogtle Units 1 and 2 owned by MEAG Power that are in effect until the later of retirement of the plant or the latest stated maturity date of MEAG Power's bonds issued to finance such ownership interest. The payments for capacity are required whether any capacity is available. The energy cost is a function of each unit's variable operating costs. Except for the portion of the capacity payments related to the Georgia PSC's disallowances of Plant Vogtle Units 1 and 2 costs, the cost of such capacity and energy is included in purchased power from non-affiliates in Georgia Power's statements of income in Item 8 herein. Also see Note 7 to the financial statements of Georgia Power under "Commitments – Fuel and Purchased Power Agreements" in Item 8 herein for additional information.

Georgia Power is currently constructing Plant Vogtle Units 3 and 4 which will be jointly owned by Georgia Power, Dalton, OPC, and MEAG Power (with each owner holding the same undivided ownership interest as shown in the table above with respect to Plant Vogtle Units 1 and 2). See Note 3 to the financial statements of Southern Company and Georgia Power under "Regulatory Matters – Georgia Power – Nuclear Construction" and "Retail Regulatory Matters – Nuclear Construction," respectively, in Item 8 herein.

Titles to Property
The traditional electric operating companies', Southern Power's, and SEGCO's interests in the principal plants (other than certain pollution control facilities and the land on which five combustion turbine generators of Mississippi Power are located, which is held by easement) and other important units of the respective companies are owned in fee by such companies, subject only to the (1) liens pursuant to pollution control revenue bonds of Gulf Power on specific pollution control facilities at Plant Daniel, (2) liens pursuant to the assumption of debt obligations by Mississippi Power in connection with the acquisition of Plant Daniel Units 3 and 4, (3) liens associated with Georgia Power's reimbursement obligations to the DOE under its loan guarantee, which are secured by a first priority lien on (a) Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 and (b) Georgia Power's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4, and (4) liens associated with two PPAs assumed as part of the acquisition of the Mankato project on October 26, 2016 by Southern Power Company. See Note 6 to the financial statements of Southern Company, Georgia Power, Gulf Power, Mississippi Power, and Southern Power under "Assets Subject to Lien," Note 6 to the financial statements of Southern Company and Georgia Power under "DOE Loan Guarantee Borrowings" and Note 6 to the financial statements of Southern Company and Mississippi Power under "Plant Daniel Revenue Bonds" in Item 8 herein for additional information. The traditional electric operating companies own the fee interests in certain of their principal plants as tenants in common. See "Jointly-Owned Facilities" herein for additional information. Properties such as electric transmission and distribution lines, steam heating mains, and gas pipelines are constructed principally on rights-of-way, which are maintained under franchise or are held by easement only. A substantial portion of lands submerged by reservoirs is held under flood right easements. In addition, certain of the renewable generating facilities occupy or use real property that is not owned, primarily through various leases, easements, rights-of-way, permits, or licenses from private landowners or governmental entities.
Natural Gas
Southern Company Gas considers its properties to be adequately maintained, substantially in good operating condition, and suitable for their intended purpose. The following provides the location and general character of the materially important properties that are used by the segments of Southern Company Gas. Substantially all of Nicor Gas' properties are subject to the lien of the indenture securing its first mortgage bonds. See Note 6 to the financial statements of Southern Company Gas under "Long-Term Debt – First Mortgage Bonds" in Item 8 herein for additional information.
Distribution and Transmission Mains – Southern Company Gas' distribution systems transport natural gas from its pipeline suppliers to customers in its service areas. These systems consist primarily of distribution and transmission mains, compressor stations, peak shaving/storage plants, service lines, meters, and regulators. At December 31, 2016, Southern Company Gas' gas distribution operations segment owned approximately 81,800 miles of underground distribution and transmission mains, which are located on easements or rights-of-way that generally provide for perpetual use.
Storage Assets – Gas Distribution Operations – Southern Company Gas owns and operates eight underground natural gas storage facilities in Illinois with a total inventory capacity of approximately 150 Bcf, approximately 135 Bcf of which can be cycled on an annual basis. This system is designed to meet about 50% of the estimated peak-day deliveries and approximately 40% of the normal winter deliveries in Illinois. This level of storage capability provides Nicor Gas with supply flexibility, improves the reliability of deliveries, and helps mitigate the risk associated with seasonal price movements.
Southern Company Gas also has five liquefied natural gas (LNG) plants located in Georgia, New Jersey, and Tennessee with total LNG storage capacity of approximately 7.6 Bcf. In addition, Southern Company Gas owns one propane storage facility in Virginia with storage capacity of approximately 0.3 Bcf. The LNG plants and propane storage facility are used by Southern Company Gas' gas distribution operations segment to supplement natural gas supply during peak usage periods.
Storage Assets – All Other – Southern Company Gas owns three high-deliverability natural gas storage and hub facilities that are operated by the gas midstream operations segment. Jefferson Island Storage & Hub, LLC operates a storage facility in Louisiana currently consisting of two salt dome gas storage caverns. Golden Triangle Storage, Inc. operates

a storage facility in Texas consisting of two salt dome caverns. Central Valley Gas Storage, LLC operates a depleted field storage facility in California. In addition, Southern Company Gas has a LNG facility in Alabama that produces LNG for Pivotal LNG, Inc. to support its business of selling LNG as a substitute fuel in various markets.

Jointly-Owned Properties – Southern Company Gas' gas midstream operations segment has a 50% undivided ownership interest in a 115-mile pipeline facility being constructed in northwest Georgia. Southern Company Gas also has an agreement to lease its 50% undivided ownership in the pipeline facility once it is placed in service. See Note 4 to the financial statements of Southern Company and Southern Company Gas in Item 8 herein for additional information.

Item 3. LEGAL PROCEEDINGS

See Note 3 to the financial statements of each registrant in Item 8 herein for descriptions of legal and administrative proceedings discussed therein.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

EXECUTIVE OFFICERS OF SOUTHERN COMPANY

(Identification of executive officers of Southern Company is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2016.

Thomas A. Fanning
Chairman, President, and Chief Executive Officer
Age 59
Elected in 2003. Chairman and Chief Executive Officer since December 2010 and President since August 2010.

Art P. Beattie
Executive Vice President and Chief Financial Officer
Age 62
Elected in 2010. Executive Vice President and Chief Financial Officer since August 2010.

W. Paul Bowers
Executive Vice President
Age 60
Elected in 2001. Executive Vice President since February 2008 and Chief Executive Officer, President, and Director of Georgia Power since January 2011. Chairman of Georgia Power's Board of Directors since May 2014.

S. W. Connally, Jr.
Chairman, President, and Chief Executive Officer of Gulf Power
Age 47
Elected in 2012. Elected Chairman in July 2015 and President, Chief Executive Officer, and Director of Gulf Power since July 2012. Previously served as Senior Vice President and Chief Production Officer of Georgia Power from August 2010 through June 2012.

Mark A. Crosswhite
Executive Vice President
Age 54
Elected in 2010. Executive Vice President since December 2010 and President, Chief Executive Officer, and Director of Alabama Power since March 2014. Chairman of Alabama Power's Board of Directors since May 2014. Previously served as Executive Vice President and Chief Operating Officer of Southern Company from July 2012 through February 2014 and President, Chief Executive Officer, and Director of Gulf Power from January 2011 through June 2012.

Andrew W. Evans
Executive Vice President
Age 50
Elected in July 2016. Executive Vice President since July 2016. President of Southern Company Gas since May 2015 and Chief Executive Officer and Chairman of Southern Company Gas' Board of Directors since January 2016. Previously served as Chief Operating Officer of Southern Company Gas from May 2015 through December 2015 and Executive Vice President and Chief Financial Officer of Southern Company Gas from May 2006 through May 2015.

Kimberly S. Greene
Executive Vice President
Age 50
Elected in 2013. Executive Vice President and Chief Operating Officer since March 2014. Director of Southern Company Gas since July 2016. Previously served as President and Chief Executive Officer of SCS from April 2013 to February 2014. Before rejoining Southern Company, Ms. Greene previously served at Tennessee Valley Authority as Executive Vice President and Chief Generation Officer from 2011 through April 2013 and Group President of Strategy and External Relations from 2010 through 2011.

James Y. Kerr II
Executive Vice President and General Counsel
Age 52

Elected in 2014. Also serves as Chief Compliance Officer. Before joining Southern Company, Mr. Kerr was a partner with McGuireWoods LLP and a senior advisor at McGuireWoods Consulting LLC from 2008 through February 2014.
Stephen E. Kuczynski
Chairman, President, and Chief Executive Officer of Southern Nuclear
Age 54
Elected in 2011. Chairman, President, and Chief Executive Officer of Southern Nuclear since July 2011.

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Mark S. Lantrip
Executive Vice President
Age 62
Elected in 2014. Chairman, President, and Chief Executive Officer of SCS since March 2014. Previously served as Treasurer of Southern Company from October 2007 to February 2014 and Executive Vice President of SCS from November 2010 to March 2014.

Anthony L. Wilson
Chairman, President, and Chief Executive Officer of Mississippi Power
Age 52
Elected in 2015. President of Mississippi Power since October 2015 and Chief Executive Officer and Director since January 2016. Chairman of Mississippi Power's Board of Directors since August 2016. Previously served as Executive Vice President of Mississippi Power from May 2015 to October 2015 and Executive Vice President of Georgia Power from January 2012 to May 2015.

Christopher C. Womack
Executive Vice President
Age 58
Elected in 2008. Executive Vice President and President of External Affairs since January 2009.

The officers of Southern Company were elected at the first meeting of the directors following the last annual meeting of stockholders held on May 25, 2016, for a term of one year or until their successors are elected and have qualified, except for Mr. Andrew W. Evans, whose election as Executive Vice President was effective July 18, 2016.

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EXECUTIVE OFFICERS OF ALABAMA POWER

(Identification of executive officers of Alabama Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2016.

Mark A. Crosswhite
Chairman, President, and Chief Executive Officer
Age 54

Elected in 2014. President, Chief Executive Officer, and Director since March 1, 2014. Chairman since May 2014. Previously served as Executive Vice President and Chief Operating Officer of Southern Company from July 2012 through February 2014 and President, Chief Executive Officer, and Director of Gulf Power from January 2011 through June 2012.

Greg J. Barker
Executive Vice President
Age 53

Elected in 2016. Executive Vice President for Customer Services since February 2016. Previously served as Senior Vice President of Marketing and Economic Development from April 2012 to February 2016 and Senior Vice President of Business Development and Customer Support from July 2010 to April 2012.

Philip C. Raymond
Executive Vice President, Chief Financial Officer, and Treasurer
Age 57

Elected in 2010. Executive Vice President, Chief Financial Officer, and Treasurer since August 2010.

Zeke W. Smith
Executive Vice President
Age 57

Elected in 2010. Executive Vice President of External Affairs since November 2010.

James P. Heilbron
Senior Vice President and Senior Production Officer
Age 45

Elected in 2013. Senior Vice President and Senior Production Officer since March 2013. Previously served as Senior Vice President and Senior Production Officer of Southern Power Company from July 2010 to February 2013.

The officers of Alabama Power were elected at the meeting of the directors held on April 22, 2016 for a term of one year or until their successors are elected and have qualified.

EXECUTIVE OFFICERS OF GEORGIA POWER

(Identification of executive officers of Georgia Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2016.

W. Paul Bowers
Chairman, President, and Chief Executive Officer
Age 60
Elected in 2010. Chief Executive Officer, President, and Director since December 2010 and Chief Operating Officer of Georgia Power from August 2010 to December 2010. Chairman of Georgia Power's Board of Directors since May 2014.

W. Craig Barrs (1)
Executive Vice President
Age 59
Elected in 2008. Executive Vice President of Customer Service and Operations since May 2015. Previously served as Executive Vice President of External Affairs from January 2010 to May 2015.

Pedro P. Cherry (1)
Executive Vice President
Age 45
Elected effective March 2017. Executive Vice President of Customer Service and Operations effective March 31, 2017. Senior Vice President since March 2015. Previously served as Vice President from January 2012 to March 2015.

W. Ron Hinson
Executive Vice President, Chief Financial Officer, and Treasurer
Age 60
Elected in 2013. Executive Vice President, Chief Financial Officer, and Treasurer since March 2013. Served as Corporate Secretary and Chief Compliance Officer from January 2016 through October 2016. Also, served as Comptroller from March 2013 until January 2014. Previously served as Comptroller and Chief Accounting Officer of Southern Company, as well as Senior Vice President and Comptroller of SCS from March 2006 to March 2013.

Christopher P. Cummiskey
Executive Vice President
Age 42
Elected in 2015. Executive Vice President of External Affairs since May 2015. Previously served as Chief Commercial Officer of Southern Power from October 2013 to May 2015 and Commissioner of the Georgia Department of Economic Development from January 2011 to October 2013.

Meredith M. Lackey
Senior Vice President, General Counsel, and Corporate Secretary
Age 42
Elected in November 2016. Senior Vice President, General Counsel, Corporate Secretary, and Chief Compliance Officer since November 2016. Previously served as Vice President, General Counsel, Chief Compliance Officer, and Corporate Secretary at Colonial Pipeline from January 2012 through November 2016.

Theodore J. McCullough
Senior Vice President and Senior Production Officer
Age 53
Elected in July 2016. Senior Vice President and Senior Production Officer since July 2016. Also has served as Senior Vice President of SCS since June 2010.

(1) On January 26, 2017, Mr. Barrs resigned the role of Executive Vice President, effective March 31, 2017. Also on January 26, 2017, Mr. Pedro P. Cherry was elected to the role of Executive Vice President, effective March 31, 2017.

The officers of Georgia Power were elected at the meeting of the directors held on May 18, 2016 for a term of one year or until their successors are elected and have qualified, except for Mr. McCullough, whose election as Senior Vice President was effective July 30, 2016, Ms. Lackey, whose election as Senior Vice President, General Counsel, and Corporate Secretary was effective November 1, 2016, and Mr. Cherry, whose election as Executive Vice President is effective March 31, 2017.

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EXECUTIVE OFFICERS OF MISSISSIPPI POWER

(Identification of executive officers of Mississippi Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2016.

Anthony L. Wilson
Chairman, President, and Chief Executive Officer
Age 52
Elected in 2015. President since October 2015 and Chief Executive Officer and Director since January 2016. Chairman of Mississippi Power's Board since August 2016. Previously served as Executive Vice President from May 2015 to October 2015 and Executive Vice President of Georgia Power from January 2012 to May 2015.

John W. Atherton
Vice President
Age 56
Elected in 2004. Vice President of Corporate Services and Community Relations since October 2012. Previously served as Vice President of External Affairs from January 2005 until October 2012.

A. Nicole Faulk
Vice President
Age 43
Elected in 2015. Vice President of Customer Services Organization effective April 2015. Previously served as Region Vice President for the West Region of Georgia Power from March 2015 through April 2015 and Region Manager for the Metro West Region of Georgia Power from December 2011 to March 2015.

Moses H. Feagin
Vice President, Treasurer, and Chief Financial Officer
Age 52
Elected in 2010. Vice President, Treasurer, and Chief Financial Officer since August 2010.

R. Allen Reaves, Jr.
Vice President
Age 57
Elected in 2010. Vice President and Senior Production Officer since August 2010.

Billy F. Thornton
Vice President
Age 56
Elected in 2012. Vice President of External Affairs since October 2012. Previously served as Director of External Affairs from October 2011 until October 2012.

Emile J. Troxclair, III
Vice President
Age 59
Elected in 2014. Vice President of Kemper Development since January 2015. Previously served as Vice President of Gasification for Lummus Technology Inc. from May 2013 through April 2014, Manager of E-Gas Technology for Phillips 66 from 2012 to May 2013, and Manager of E-Gas Technology for ConocoPhillips from 2003 to 2012.

The officers of Mississippi Power were elected at the meeting of the directors held on April 26, 2016 for a term of one year or until their successors are elected and have qualified.

PART II

Item 5. MARKET FOR REGISTRANTS' COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

(a)(1) The common stock of Southern Company is listed and traded on the NYSE. The common stock is also traded on regional exchanges across the U.S. The high and low stock prices as reported on the NYSE for each quarter of the past two years were as follows:

	High	Low
2016		
First Quarter	$51.73	$46.00
Second Quarter	53.64	47.62
Third Quarter	54.64	50.00
Fourth Quarter	52.23	46.20
2015		
First Quarter	$53.16	$43.55
Second Quarter	45.44	41.40
Third Quarter	46.84	41.81
Fourth Quarter	47.50	43.38

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

(a)(2) Number of Southern Company's common stockholders of record at January 31, 2017: 125,827

Each of the other registrants have one common stockholder, Southern Company.

(a)(3) Dividends on each registrant's common stock are payable at the discretion of their respective board of directors. The dividends on common stock declared by Southern Company and the traditional electric operating companies (other than Mississippi Power) to their stockholder(s) for the past two years are set forth below. No dividends were declared by Mississippi Power on its common stock in 2015 or 2016.

Registrant	Quarter	2016	2015
		(in thousands)	
Southern Company	First	$496,718	$478,454
	Second	526,267	493,161
	Third	529,876	493,382
	Fourth	551,110	493,884
Alabama Power	First	191,206	142,820
	Second	191,206	142,820
	Third	191,206	142,820
	Fourth	191,206	142,820
Georgia Power	First	326,269	258,570
	Second	326,269	258,870
	Third	326,269	258,870
	Fourth	326,269	258,870
Gulf Power	First	30,017	32,540
	Second	30,017	32,540
	Third	30,017	32,540
	Fourth	30,017	32,540

In 2016 and 2015, Southern Power Company paid dividends to Southern Company as follows:

Registrant	Quarter	2016	2015
		(in thousands)	
Southern Power Company	First	$68,082	$32,640
	Second	68,082	32,640
	Third	68,082	32,640
	Fourth	68,082	32,640

Southern Company Gas paid dividends to Southern Company in the amount of $62,750,000 in each of the third and fourth quarters 2016.

The dividend paid per share of Southern Company's common stock was 54.25¢ for the first quarter 2016 and 56.00¢ each for the second, third, and fourth quarters of 2016. In 2015, Southern Company paid a dividend per share of 52.50¢ for the first quarter and 54.25¢ each for the second, third, and fourth quarters.

The traditional electric operating companies and Southern Power Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital. The authority of the natural gas distribution utilities to pay dividends to Southern Company Gas is subject to regulation. By regulation, Nicor Gas is restricted, to the extent of its retained earnings balance, in the amount it can dividend or loan to affiliates. Additionally, Elizabethtown Gas is restricted by its policy, as established by the New Jersey Board of Public Utilities, to 70% of its quarterly net income it can dividend to Southern Company Gas.

(a)(4) Securities authorized for issuance under equity compensation plans.

See Part III, Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

(b) Use of Proceeds

Not applicable.

(c) Issuer Purchases of Equity Securities

None.

Item 6. SELECTED FINANCIAL DATA

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of each of the registrants in Item 7 herein and Note 1 of each of the registrant's financial statements under "Financial Instruments" in Item 8 herein. See also Note 10 to the financial statements of Southern Company, Alabama Power, and Georgia Power, Note 9 to the financial statements of Gulf Power, Mississippi Power, and Southern Company Gas, and Note 8 to the financial statements of Southern Power in Item 8 herein.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

Item 9A. CONTROLS AND PROCEDURES

Disclosure Controls And Procedures.

As of the end of the period covered by this Annual Report on Form 10-K, Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and Southern Company Gas conducted separate evaluations under the supervision and with the participation of each company's management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended). Based upon these evaluations, the Chief Executive Officer and the Chief Financial Officer, in each case, concluded that the disclosure controls and procedures are effective.

Internal Control Over Financial Reporting.

(a) Management's Annual Report on Internal Control Over Financial Reporting.

Management's Report on Internal Control Over Financial Reporting	Page
Southern Company	II-8
Alabama Power	II-153
Georgia Power	II-231
Gulf Power	II-315
Mississippi Power	II-384
Southern Power	II-480
Southern Company Gas	II-540

(b) Attestation Report of the Registered Public Accounting Firm.

The report of Deloitte & Touche LLP, Southern Company's independent registered public accounting firm, regarding Southern Company's Internal Control over Financial Reporting is included on page II-9 of this Form 10-K. This report is not applicable to Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and Southern Company Gas as these companies are not accelerated filers or large accelerated filers.

(c) Changes in internal control over financial reporting.

Other than the changes resulting from the Merger discussed below, there have been no changes in Southern Company's, Alabama Power's, Georgia Power's, Gulf Power's, Mississippi Power's, Southern Power's, or Southern Company Gas' internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended) during the fourth quarter 2016 that have materially affected or are reasonably likely to materially affect Southern Company's, Alabama Power's, Georgia Power's, Gulf Power's, Mississippi Power's, Southern Power's, or Southern Company Gas' internal control over financial reporting.

Southern Company completed the Merger on July 1, 2016 with Southern Company Gas surviving the Merger as a wholly-owned, direct subsidiary of Southern Company. Southern Company has completed an internal controls review during the fourth quarter 2016 pursuant to Section 404 of the Sarbanes-Oxley Act of 2002.

Item 9B. OTHER INFORMATION

None.

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Southern Company and Subsidiary Companies 2016 Annual Report

The management of The Southern Company (Southern 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 Southern 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 Southern Company's internal control over financial reporting was effective as of December 31, 2016.

Deloitte & Touche LLP, an independent registered public accounting firm, as auditors of Southern Company's financial statements, has issued an attestation report on the effectiveness of Southern Company's internal control over financial reporting as of December 31, 2016. Deloitte & Touche LLP's report on Southern Company's internal control over financial reporting is included herein.

/s/ Thomas A. Fanning
Thomas A. Fanning
Chairman, President, and Chief Executive Officer

/s/ Art P. Beattie
Art P. Beattie
Executive Vice President and Chief Financial Officer

February 21, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors and Stockholders of
The Southern Company
We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of The Southern Company and Subsidiary Companies (the Company) as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2016. We also have audited the Company's internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting (page II-8). Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting 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 and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.
A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.
Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.
In our opinion, the consolidated financial statements (pages II-59 to II-147) referred to above present fairly, in all material respects, the financial position of Southern Company and Subsidiary Companies as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

As discussed in Note 3 to the financial statements, the Mississippi Public Service Commission rate recovery process associated with the Kemper Integrated Coal Gasification Combined Cycle Project may have a material impact on the Company's financial statements.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 21, 2017

DEFINITIONS

Term	Meaning
2012 MPSC CPCN Order	A detailed order issued by the Mississippi PSC in April 2012 confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing acquisition, construction, and operation of the Kemper IGCC
2013 ARP	Alternative Rate Plan approved by the Georgia PSC in 2013 for Georgia Power for the years 2014 through 2016 and subsequently extended through 2019
AFUDC	Allowance for funds used during construction
Alabama Power	Alabama Power Company
ARO	Asset retirement obligation
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
Atlanta Gas Light	Atlanta Gas Light Company, a wholly-owned subsidiary of Southern Company Gas
Baseload Act	State of Mississippi legislation designed to enhance the Mississippi PSC's authority to facilitate development and construction of baseload generation in the State of Mississippi
CCR	Coal combustion residuals
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
COD	Commercial operation date
CPCN	Certificate of public convenience and necessity
CWIP	Construction work in progress
DOE	U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FFB	Federal Financing Bank
GAAP	U.S. generally accepted accounting principles
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
IGCC	Integrated coal gasification combined cycle
IRS	Internal Revenue Service
ITC	Investment tax credit
Kemper IGCC	IGCC facility under construction by Mississippi Power in Kemper County, Mississippi
KWH	Kilowatt-hour
LIBOR	London Interbank Offered Rate
Merger	The merger, effective July 1, 2016, of a wholly-owned, direct subsidiary of Southern Company with and into Southern Company Gas, with Southern Company Gas continuing as the surviving corporation
Mirror CWIP	A regulatory liability used by Mississippi Power to record customer refunds resulting from a 2015 Mississippi PSC order
Mississippi Power	Mississippi Power Company
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MPUS	Mississippi Public Utilities Staff
MW	Megawatt
natural gas distribution utilities	Southern Company Gas' seven natural gas distribution utilities (Nicor Gas, Atlanta Gas Light, Virginia Natural Gas, Inc., Elizabethtown Gas, Florida City Gas, Chattanooga Gas Company, and Elkton Gas)

DEFINITIONS
(continued)

Term	Meaning
NCCR	Georgia Power's Nuclear Construction Cost Recovery
NDR	Alabama Power's Natural Disaster Reserve
Nicor Gas	Northern Illinois Gas Company, a wholly-owned subsidiary of Southern Company Gas
NRC	U.S. Nuclear Regulatory Commission
OCI	Other comprehensive income
Plant Vogtle Units 3 and 4	Two new nuclear generating units under construction at Georgia Power's Plant Vogtle
PowerSecure	PowerSecure, Inc.
power pool	The operating arrangement whereby the integrated generating resources of the traditional electric operating companies and Southern Power (excluding subsidiaries) are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power purchase agreements and contracts for differences that provide the owner of a renewable facility a certain fixed price for the electricity sold to the grid
PSC	Public Service Commission
PTC	Production tax credit
Rate CNP	Alabama Power's Rate Certificated New Plant
Rate CNP Compliance	Alabama Power's Rate Certificated New Plant Compliance
Rate CNP PPA	Alabama Power's Rate Certificated New Plant Power Purchase Agreement
Rate ECR	Alabama Power's Rate Energy Cost Recovery
Rate NDR	Alabama Power's Rate Natural Disaster Reserve
Rate RSE	Alabama Power's Rate Stabilization and Equalization plan
ROE	Return on equity
S&P	S&P Global Ratings, a division of S&P Global Inc.
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	U.S. Securities and Exchange Commission
SEGCO	Southern Electric Generating Company
SMEPA	South Mississippi Electric Power Association (now known as Cooperative Energy)
Southern Company Gas	Southern Company Gas (formerly known as AGL Resources Inc.) and its subsidiaries
Southern Company Gas Capital	Southern Company Gas Capital Corporation (formerly known as AGL Capital Corporation), a 100%-owned subsidiary of Southern Company Gas
Southern Company system	The Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), SEGCO, Southern Nuclear, SCS, Southern LINC, PowerSecure (as of May 9, 2016), and other subsidiaries
Southern LINC	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
traditional electric operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power
Westinghouse	Westinghouse Electric Company LLC

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Southern Company and Subsidiary Companies 2016 Annual Report
OVERVIEW
Business Activities
The Southern Company (Southern Company or the Company) is a holding company that owns all of the common stock of the traditional electric operating companies and the parent entities of Southern Power and Southern Company Gas and owns other direct and indirect subsidiaries. The primary business of the Southern Company system is electricity sales by the traditional electric operating companies and Southern Power and, following the closing of the Merger on July 1, 2016, the distribution of natural gas by Southern Company Gas. The four traditional electric operating companies are vertically integrated utilities providing electric service in four Southeastern states. Southern Power constructs, acquires, owns, and manages power generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. Southern Company Gas distributes natural gas through the natural gas distribution utilities in seven states and is involved in several other complementary businesses including gas marketing services, wholesale gas services, and gas midstream operations.
Many factors affect the opportunities, challenges, and risks of the Southern Company system's electricity and natural gas businesses. These factors include the ability to maintain constructive regulatory environments, to maintain and grow sales and customers, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, stringent environmental standards, reliability, fuel, restoration following major storms, and capital expenditures, including constructing new electric generating plants, expanding the electric transmission and distribution systems, and updating and expanding the natural gas distribution systems. Construction continues on Plant Vogtle Units 3 and 4 (45.7% ownership interest by Georgia Power in the two units, each with approximately 1,100 MWs) and Mississippi Power's 582-MW Kemper IGCC. See Note 3 to the financial statements under "Regulatory Matters – Georgia Power – Nuclear Construction" and "Integrated Coal Gasification Combined Cycle" for additional information.
The traditional electric operating companies and natural gas distribution utilities have 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 Southern Company system for the foreseeable future. See Note 3 to the financial statements under "Regulatory Matters" and "Integrated Coal Gasification Combined Cycle" for additional information.
Another major factor affecting the Southern Company system's businesses is the profitability of the competitive market-based wholesale generating business. Southern Power's strategy is to construct, acquire, own, manage, and sell power generation assets, including renewable energy projects, and to enter into PPAs primarily with investor-owned utilities, independent power producers, municipalities, and other load-serving entities.
Southern Company's other business activities include providing energy technologies and services to electric utilities and large industrial, commercial, institutional, and municipal customers. Customer solutions include distributed generation systems, utility infrastructure solutions, and energy efficiency products and services. Other business activities also include investments in telecommunications, leveraged lease projects, and gas storage facilities. Management continues to evaluate the contribution of each of these activities to total shareholder return and may pursue acquisitions, dispositions, and other strategic ventures or investments accordingly.
In striving to achieve attractive risk-adjusted returns while providing cost-effective energy to more than nine million electric and gas utility customers, the Southern Company system continues to focus on several key performance indicators. These indicators include, but are not limited to, customer satisfaction, plant availability, electric and natural gas system reliability, execution of major construction projects, and earnings per share (EPS). Southern Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the results of the Southern Company system.
See RESULTS OF OPERATIONS herein for information on the Company's financial performance.
Merger with Southern Company Gas

On July 1, 2016, Southern Company completed the Merger for a total purchase price of approximately $8.0 billion and Southern Company Gas became a wholly-owned, direct subsidiary of Southern Company.

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Prior to the completion of the Merger, Southern Company and Southern Company Gas operated as separate companies. The discussion and analysis of results of operations and financial condition set forth herein includes Southern Company Gas' results of operations since July 1, 2016 and financial condition as of December 31, 2016. See Note 12 to the financial statements under "Southern Company – Merger with Southern Company Gas" for additional information regarding the Merger.

During 2016 and 2015, the Company recorded in its statements of income costs associated with the Merger of approximately $111 million and $41 million, respectively, of which $80 million and $27 million is included in operating expenses and $31 million and $14 million is included in other income and (expense), respectively. These costs include external transaction costs for financing, legal, and consulting services, as well as customer rate credits and additional compensation-related expenses.

Earnings

Consolidated net income attributable to Southern Company was $2.4 billion in 2016, an increase of $81 million, or 3.4%, from the prior year. Consolidated net income increased by $114 million as a result of earnings from Southern Company Gas, which was acquired on July 1, 2016. Also contributing to the increase were higher retail electric revenues resulting from non-fuel retail rate increases and warmer weather, primarily in the third quarter 2016, as well as the 2015 correction of a Georgia Power billing error, partially offset by accruals in 2016 for expected refunds at Alabama Power and Georgia Power. Additionally, the increase was due to increases in income tax benefits and renewable energy sales at Southern Power. These increases were partially offset by higher interest expense, non-fuel operations and maintenance expenses, depreciation and amortization, lower wholesale capacity revenues, and higher estimated losses associated with the Kemper IGCC. See Note 12 to the financial statements under "Southern Company – Merger with Southern Company Gas" for additional information regarding the Merger.

Consolidated net income attributable to Southern Company was $2.4 billion in 2015, an increase of $404 million, or 20.6%, from the prior year. The increase was primarily related to lower pre-tax charges of $365 million ($226 million after tax) recorded in 2015 compared to pre-tax charges of $868 million ($536 million after tax) recorded in 2014 for revisions of the estimated costs expected to be incurred on Mississippi Power's construction of the Kemper IGCC and an increase in retail base rates. The increases were partially offset by increases in non-fuel operations and maintenance expenses and depreciation and amortization.

Basic EPS was $2.57 in 2016, $2.60 in 2015, and $2.19 in 2014. Diluted EPS, which factors in additional shares related to stock-based compensation, was $2.55 in 2016, $2.59 in 2015, and $2.18 in 2014. EPS for 2016 was negatively impacted by $0.12 per share as a result of an increase in the average shares outstanding. See FINANCIAL CONDITION AND LIQUIDITY – "Financing Activities" herein for additional information.

Dividends

Southern Company has paid dividends on its common stock since 1948. Dividends paid per share of common stock were $2.2225 in 2016, $2.1525 in 2015, and $2.0825 in 2014. In January 2017, Southern Company declared a quarterly dividend of 56 cents per share. This is the 277th consecutive quarter that Southern Company has paid a dividend equal to or higher than the previous quarter. For 2016, the dividend payout ratio was 86%.

RESULTS OF OPERATIONS

Discussion of the results of operations is divided into three parts – the Southern Company system's primary business of electricity sales, its gas business, and its other business activities.

	Amount		
	2016	2015	2014
	(in millions)		
Electricity business	$2,571	$2,401	$1,969
Gas business	114	—	—
Other business activities	(237)	(34)	(6)

Net Income	$2,448	$2,367	$1,963

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Electricity Business

Southern Company's electric utilities generate and sell electricity to retail and wholesale customers primarily in the Southeast.

A condensed statement of income for the electricity business follows:

	Amount	Increase (Decrease) from Prior Year	
	2016	2016	2015
	(in millions)		
Electric operating revenues	$17,941	$ 499	$ (964)
Fuel	4,361	(389)	(1,255)
Purchased power	750	105	(27)
Cost of other sales	58	58	—
Other operations and maintenance	4,523	231	33
Depreciation and amortization	2,233	213	91
Taxes other than income taxes	1,039	44	16
Estimated loss on Kemper IGCC	428	63	(503)
Total electric operating expenses	13,392	325	(1,645)
Operating income	4,549	174	681
Allowance for equity funds used during construction	200	(26)	(19)
Interest expense, net of amounts capitalized	931	157	(20)
Other income (expense), net	(75)	(43)	23
Income taxes	1,091	(235)	273
Net income	2,652	183	432
Less:			
Dividends on preferred and preference stock of subsidiaries	45	(9)	(14)
Net income attributable to noncontrolling interests	36	22	14
Net Income Attributable to Southern Company	$2,571	$ 170	$ 432

Electric Operating Revenues

Electric operating revenues for 2016 were $17.9 billion, reflecting a $499 million increase from 2015. Details of electric operating revenues were as follows:

	Amount	
	2016	2015
	(in millions)	
Retail electric — prior year	$14,987	$15,550
Estimated change resulting from —		
Rates and pricing	427	375
Sales growth (decline)	(35)	50
Weather	153	(59)
Fuel and other cost recovery	(298)	(929)
Retail electric — current year	15,234	14,987
Wholesale electric revenues	1,926	1,798
Other electric revenues	698	657
Other revenues	83	—
Electric operating revenues	$17,941	$17,442
Percent change	2.9%	(5.2)%

Retail electric revenues increased $247 million, or 1.6%, in 2016 as compared to the prior year. The significant factors driving this change are shown in the preceding table. The increase in rates and pricing in 2016 was primarily due to increases in base tariffs at Georgia Power under the 2013 ARP and the NCCR tariff and increased revenues at Alabama Power under Rate CNP Compliance, all effective January 1, 2016. Also contributing to the increase in rates and pricing for 2016 was the 2015 correction of an error affecting billings since 2013 to a small number of large commercial and industrial customers under a rate plan allowing for variable demand-driven pricing at Georgia Power and the implementation of rates at Mississippi Power for certain Kemper IGCC in-service assets, effective September 2015. These increases were partially offset by accruals in 2016 for expected refunds at Alabama Power and Georgia Power.

Retail electric revenues decreased $563 million, or 3.6%, in 2015 as compared to the prior year. The significant factors driving this change are shown in the preceding table. The increase in rates and pricing in 2015 was primarily due to increased revenues at Alabama Power, associated with an increase in rates under Rate RSE, and at Georgia Power, related to increases in base tariffs under the 2013 ARP and the NCCR tariff, all effective January 1, 2015, as well as higher contributions from variable demand-driven pricing from commercial and industrial customers. The increase in rates and pricing was also due to the implementation of rates at Mississippi Power for certain Kemper IGCC in-service assets, effective September 2015. The increase was partially offset by the 2015 correction of an error affecting billings since 2013 to a small number of large commercial and industrial customers under a rate plan allowing for variable demand-driven pricing at Georgia Power.

See Note 3 to the financial statements under "Regulatory Matters – Alabama Power – Rate RSE" and " – Rate CNP Compliance" and " – Georgia Power – Rate Plans" and " – Nuclear Construction" and "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs" and Note 1 to the financial statements under "General" for additional information. Also see "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (decline) and weather.

Electric rates for the traditional electric operating companies include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, including the energy component of PPA costs, and do not affect net income. The traditional electric operating companies each have one or more regulatory mechanisms to recover other costs such as environmental and other compliance costs, storm damage, new plants, and PPA capacity costs.

Wholesale electric revenues consist of PPAs primarily with investor-owned utilities and electric cooperatives and short-term opportunity sales. Wholesale electric revenues from PPAs (other than solar and wind PPAs) have both capacity and energy components. Capacity revenues generally represent the greatest contribution to net income and are designed to provide recovery of fixed costs plus a return on investment. Energy revenues will vary depending on fuel prices, the market prices of wholesale energy compared to the Southern Company system's generation, demand for energy within the Southern Company system's electric service territory, and the availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income. Electricity sales from solar and wind PPAs do not have a capacity charge and customers either purchase the energy output of a dedicated renewable facility through an energy charge or through a fixed price for electricity. As a result, the Company's ability to recover fixed and variable operations and maintenance expenses is dependent upon the level of energy generated from these facilities, which can be impacted by weather conditions, equipment performance, and other factors. Wholesale electric revenues at Mississippi Power include FERC-regulated municipal and rural association sales as well as market-based sales. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Southern Company system's variable cost to produce the energy.

Wholesale electric revenues from power sales were as follows:

	2016	2015	2014
	(in millions)		
Capacity and other	$771	$875	$974
Energy	1,155	923	1,210
Total	$1,926	$1,798	$2,184

In 2016, wholesale revenues increased $128 million, or 7.1%, as compared to the prior year due to a $232 million increase in energy revenues, offset by a $104 million decrease in capacity revenues. The increase in energy revenues was primarily due to an increase in short-term sales and renewable energy sales at Southern Power, partially offset by lower fuel prices. The decrease in capacity revenues was primarily due to the expiration of wholesale contracts at Georgia Power and Gulf Power, the elimination in consolidation of a Southern Power PPA that was remarketed from a third party to Georgia Power in January 2016, and unit retirements at Georgia Power, partially offset by an increase due to a new wholesale contract at Alabama Power in the first quarter 2016.

In 2015, wholesale revenues decreased $386 million, or 17.7%, as compared to the prior year due to a $287 million decrease in energy revenues and a $99 million decrease in capacity revenues. The decreases in energy revenues were primarily related to lower fuel costs and lower customer demand due to milder weather as compared to the prior year, partially offset by increases in energy revenues from new solar and wind PPAs at Southern Power. The decreases in capacity revenues were primarily due to the expiration of wholesale contracts in December 2014 at Georgia Power, unit retirements at Georgia Power, and PPA expirations at Southern Power.

See FUTURE EARNINGS POTENTIAL – "Regulatory Matters – Gulf Power" for information regarding the expiration of long-term sales agreements at Gulf Power for Plant Scherer Unit 3, which will impact future wholesale earnings, and Gulf Power's request to rededicate its ownership interest in Scherer Unit 3 to the retail jurisdiction.

Other Electric Revenues

Other electric revenues increased $41 million, or 6.2%, and decreased $15 million, or 2.2%, in 2016 and 2015, respectively, as compared to the prior years. The 2016 increase was primarily due to a $14 million increase in customer temporary facilities services revenues and a $12 million increase in outdoor lighting revenues at Georgia Power. The 2015 decrease was primarily due to a $16 million decrease in transmission revenues at Georgia Power primarily as a result of a contract that expired in December 2014 and a $13 million decrease in co-generation steam revenues at Alabama Power, partially offset by an $11 million increase in outdoor lighting revenues at Georgia Power.

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Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2016 and the percent change from the prior year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2016	2016	2015	2016(*)	2015(*)
	(in billions)				
Residential	53.3	2.3 %	(2.3)%	0.2 %	0.4 %
Commercial	53.7	0.4	0.5	(1.0)	0.9
Industrial	52.8	(2.1)	(0.4)	(2.2)	(0.3)
Other	0.9	(1.7)	(1.4)	(1.7)	(1.3)
Total retail	160.7	0.2	(0.7)	(1.0)%	0.3 %
Wholesale	34.9	14.4	(7.0)		
Total energy sales	195.6	2.4 %	(1.8)%		

(*) In the first quarter 2015, Mississippi Power updated the methodology to estimate the unbilled revenue allocation among customer classes. This change did not have a significant impact on net income. The KWH sales variances in the above table reflect an adjustment to the estimated allocation of Mississippi Power's unbilled 2014 and first quarter 2015 KWH sales among customer classes that is consistent with the actual allocation in 2015 and 2016, respectively. Without this adjustment, 2016 weather-adjusted commercial sales decreased 0.9% and industrial KWH sales decreased 2.1% as compared to 2015. Without this adjustment, 2015 weather-adjusted commercial sales increased 0.8% and industrial KWH sales decreased 0.4% as compared to 2014.

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 increased 261 million KWHs in 2016 as compared to the prior year. This increase was primarily due to warmer weather in the third quarter 2016 as compared to the corresponding period in 2015 and customer growth, partially offset by decreased customer usage. The decrease in industrial KWH energy sales was primarily due to decreased sales in the primary metals, chemicals, paper, pipeline, and stone, clay, and glass sectors. A strong dollar, low oil prices, and weak global economic conditions constrained growth in the industrial sector in 2016. Weather-adjusted commercial KWH sales decreased primarily due to decreased customer usage resulting from an increase in electronic commerce transactions and energy saving initiatives, partially offset by customer growth. Weather-adjusted residential KWH sales increased primarily due to customer growth, partially offset by decreased customer usage primarily resulting from an increase in multi-family housing and efficiency improvements in residential appliances and lighting. Household income, one of the primary drivers of residential customer usage, had modest growth in 2016.

Retail energy sales decreased 1.2 billion KWHs in 2015 as compared to the prior year. This decrease was primarily the result of milder weather in the first and fourth quarters of 2015 as compared to the corresponding periods in 2014 and decreased customer usage, partially offset by customer growth. Weather-adjusted commercial KWH sales increased primarily due to customer growth and increased customer usage. Weather-adjusted residential KWH sales increased primarily due to customer growth, partially offset by decreased customer usage. Household income, one of the primary drivers of residential customer usage, had modest growth in 2015. The decrease in industrial KWH energy sales was primarily due to decreased sales in the primary metals, chemicals, and paper sectors, partially offset by increased sales in the transportation, stone, clay, and glass, pipeline, lumber, and petroleum sectors. A strong dollar, low oil prices, and weak global economic conditions constrained growth in the industrial sector in 2015.

See "Electric Operating Revenues" above for a discussion of significant changes in wholesale revenues related to changes in price and KWH sales.

Other Revenues

Other revenues increased $83 million in 2016 as compared to the prior year. The 2016 increase was primarily due to revenues from certain non-regulated sales of products and services by the traditional electric operating companies that were reclassified as other revenues for consistency of presentation on a consolidated basis following the PowerSecure acquisition. In prior periods, these revenues were included in other income (expense), net.

Fuel and Purchased Power Expenses

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

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

	2016	2015	2014
Total generation (in billions of KWHs)	188	187	191
Total purchased power (in billions of KWHs)	16	13	12
Sources of generation (percent) —			
Coal	33	34	42
Nuclear	16	16	16
Gas	46	46	39
Hydro	2	3	3
Other Renewables	3	1	—
Cost of fuel, generated (in cents per net KWH) —			
Coal	3.04	3.55	3.81
Nuclear	0.81	0.79	0.87
Gas	2.48	2.60	3.63
Average cost of fuel, generated (in cents per net KWH)	2.40	2.64	3.25
Average cost of purchased power (in cents per net KWH)(*)	5.43	6.11	7.13

(*) Average cost of purchased power includes fuel purchased by the Southern Company system for tolling agreements where power is generated by the provider.

In 2016, total fuel and purchased power expenses were $5.1 billion, a decrease of $284 million, or 5.3%, as compared to the prior year. The decrease was primarily the result of a $518 million decrease in the average cost of fuel and purchased power primarily due to lower coal and natural gas prices, partially offset by a $234 million increase in the volume of KWHs generated and purchased.

In 2015, total fuel and purchased power expenses were $5.4 billion, a decrease of $1.3 billion, or 19.2%, as compared to the prior year. The decrease was primarily the result of a $1.1 billion decrease in the average cost of fuel and purchased power primarily due to lower coal and natural gas prices and a $137 million net decrease in the volume of KWHs generated and purchased due to milder weather in the first and fourth quarters of 2015.

Fuel and purchased power energy transactions at the traditional electric operating companies are generally offset by fuel revenues and do not have a significant impact on net income. See FUTURE EARNINGS POTENTIAL – "Regulatory Matters – Fuel Cost Recovery" herein for additional information. Fuel expenses incurred under Southern Power's PPAs are generally the responsibility of the counterparties and do not significantly impact net income.

Fuel

In 2016, fuel expense was $4.4 billion, a decrease of $389 million, or 8.2%, as compared to the prior year. The decrease was primarily due to a 14.4% decrease in the average cost of coal per KWH generated, a 4.6% decrease in the average cost of natural gas per KWH generated, and a 2.7% decrease in the volume of KWHs generated by coal, partially offset by a 3.5% increase in the volume of KWHs generated by natural gas.

In 2015, fuel expense was $4.8 billion, a decrease of $1.3 billion, or 20.9%, as compared to the prior year. The decrease was primarily due to a 28.4% decrease in the average cost of natural gas per KWH generated, a 19.2% decrease in the volume of KWHs generated by coal, and a 6.8% decrease in the average cost of coal per KWH generated, partially offset by a 15.9% increase in the volume of KWHs generated by natural gas.

Purchased Power

In 2016, purchased power expense was $750 million, an increase of $105 million, or 16.3%, as compared to the prior year. The increase was primarily due to a 28.8% increase in the volume of KWHs purchased, partially offset by an 11.1% decrease in the average cost per KWH purchased primarily as a result of lower natural gas prices.

In 2015, purchased power expense was $645 million, a decrease of $27 million, or 4.0%, as compared to the prior year. The decrease was primarily due to a 14.3% decrease in the average cost per KWH purchased primarily as a result of lower natural gas prices, partially offset by a 5.3% increase in the volume of KWHs purchased.

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

Cost of Other Sales

Cost of other sales were $58 million in 2016. These costs were related to certain non-regulated sales of products and services by the traditional electric operating companies that were reclassified as cost of other sales for consistency of presentation on a consolidated basis following the PowerSecure acquisition. In prior periods, these costs were included in other income (expense), net.

Other Operations and Maintenance Expenses

Other operations and maintenance expenses increased $231 million, or 5.4%, in 2016 as compared to the prior year. The increase was primarily related to a $76 million increase in transmission and distribution expenses primarily related to overhead line maintenance, a $37 million decrease in gains from sales of assets at Georgia Power, a $36 million charge in connection with cost containment activities at Georgia Power, and a $35 million increase at Southern Power associated with new solar and wind facilities placed in service in 2015 and 2016. Additionally, the increase was due to a $19 million increase in generation expenses primarily related to environmental costs, a $19 million increase in business development and support expenses at Southern Power, and an $11 million increase in scheduled outage and maintenance costs at generation facilities, partially offset by a $41 million net decrease in employee compensation and benefits, including pension costs.

Other operations and maintenance expenses increased $33 million, or 0.8%, in 2015 as compared to the prior year. The increase was primarily related to an $84 million increase in employee compensation and benefits including pension costs, a $62 million increase in generation expenses primarily related to environmental costs, and an $11 million increase in customer accounts, service, and sales costs primarily related to customer incentive and demand-side management programs, partially offset by a $99 million decrease in transmission and distribution costs primarily related to reduced overhead line maintenance and gains from sales of transmission assets and a $32 million decrease in scheduled outage and maintenance costs at generation facilities.

Production expenses and transmission and distribution expenses fluctuate from year to year due to variations in outage and maintenance schedules and normal changes in the cost of labor and materials.

Depreciation and Amortization

Depreciation and amortization increased $213 million, or 10.5%, in 2016 as compared to the prior year primarily due to additional plant in service at the traditional electric operating companies and Southern Power.

Depreciation and amortization increased $91 million, or 4.7%, in 2015 as compared to the prior year primarily due to the amortization of $120 million of the regulatory liability for other cost of removal obligations in 2014 at Alabama Power and increases in additional plant in service at the traditional electric operating companies and Southern Power, partially offset by a decrease as a result of a reduction in depreciation rates at Alabama Power effective January 1, 2015, a decrease due to unit retirements at Georgia Power, and a reduction in depreciation at Gulf Power as authorized in the 2013 rate case settlement agreement approved by the Florida PSC. See Note 3 to the financial statements under "Regulatory Matters – Gulf Power – Retail Base Rate Cases" for additional information.

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

Taxes Other Than Income Taxes

Taxes other than income taxes increased $44 million, or 4.4%, in 2016 as compared to the prior year primarily due to an increase in property taxes due to higher assessed value of property at the traditional electric operating companies, increases in state and municipal utility license tax bases at Alabama Power, an increase in payroll taxes at Georgia Power, and an increase in franchise taxes at Mississippi Power.

Taxes other than income taxes increased $16 million, or 1.6%, in 2015 as compared to the prior year primarily due to an increase in property taxes due to higher assessed value of property at the traditional electric operating companies.

Estimated Loss on Kemper IGCC

In 2016, 2015, and 2014, estimated probable losses on the Kemper IGCC of $428 million, $365 million, and $868 million, respectively, were recorded at Southern Company. These losses reflect revisions of estimated costs expected to be incurred on Mississippi Power's construction of the Kemper IGCC in excess of the $2.88 billion cost cap established by the Mississippi PSC, net of $245 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (Initial DOE Grants) and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, AFUDC, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when Mississippi Power demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on customers relative to the original proposal for the CPCN) (Cost Cap Exceptions). The 2016 loss also reflects $80 million associated with the estimated minimum probable amount of costs not currently in rates that would not be recovered under the probable rate mitigation plan to be filed by June 3, 2017.

See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

Allowance for Equity Funds Used During Construction

AFUDC equity decreased $26 million, or 11.5%, in 2016 as compared to the prior year primarily due to environmental and generation projects being placed in service at Alabama Power and Gulf Power, partially offset by a higher AFUDC rate and an increase in Kemper IGCC CWIP subject to AFUDC at Mississippi Power.

AFUDC equity decreased $19 million, or 7.8%, in 2015 as compared to the prior year primarily due to a reduction in the AFUDC rate at Mississippi Power, as well as placing the combined cycle and the associated common facilities portion of the Kemper IGCC in service in August 2014, partially offset by an increase in construction projects related to environmental and steam generation at Alabama Power.

See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized increased $157 million, or 20.3%, in 2016 as compared to the prior year primarily due to an increase in interest expense at Southern Power related to additional debt issued primarily to fund its growth strategy and continuous construction program, increases in both the average outstanding long-term debt balance and the average interest rate at the traditional electric operating companies, and the May 2015 termination of an asset purchase agreement between Mississippi Power and SMEPA and the resulting reversal of accrued interest on related deposits.

Interest expense, net of amounts capitalized decreased $20 million, or 2.5%, in 2015 as compared to the prior year primarily due to a decrease of $58 million at Mississippi Power related to the termination of an agreement for SMEPA to purchase a portion of the Kemper IGCC which required the return of SMEPA's deposits at a lower rate of interest than accrued and a $14 million decrease primarily due to an increase in capitalized interest associated with the construction of solar facilities at Southern Power, partially offset by a $46 million increase due to higher average outstanding long-term debt balances at the traditional electric operating companies.

See Note 6 to the financial statements for additional information.

Other Income (Expense), Net

Other income (expense), net decreased $43 million, or 134.4%, in 2016 as compared to the prior year primarily due to the reclassification of revenues and costs associated with certain non-regulated sales of products and services by the traditional electric operating companies to other revenues and cost of other sales for consistency of presentation on a consolidated basis following the PowerSecure acquisition. The net amounts reclassified were $25 million. Also contributing to the decrease was an $8 million decrease in customer contributions in aid of construction (CIAC) and a $6 million decrease in wholesale operating fee revenue at Georgia Power.

Other income (expense), net increased $23 million, or 41.8%, in 2015 as compared to the prior year primarily due to an increase of $9 million in wholesale operating fee revenues, an increase of $9 million in customer CIAC at Georgia Power, and an increase due to Mississippi Power's $7 million settlement with the Sierra Club in 2014, partially offset by a decrease in sales of non-utility property at Alabama Power.

Income Taxes

Income taxes decreased $235 million, or 17.7%, in 2016 as compared to the prior year primarily due to increased federal income tax benefits related to ITCs for solar plants placed in service and PTCs from wind generation at Southern Power in 2016.

Income taxes increased $273 million, or 25.9%, in 2015 as compared to the prior year primarily due to a reduction in tax benefits related to the estimated probable losses on Mississippi Power's construction of the Kemper IGCC recorded in 2014 and higher pre-tax earnings, partially offset by increased federal income tax benefits related to ITCs at Southern Power in 2015.

See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Gas Business

Southern Company Gas distributes natural gas through utilities in seven states and is involved in several other complementary businesses including gas marketing services, wholesale gas services, and gas midstream operations. On July 1, 2016, Southern Company Gas became a wholly-owned, direct subsidiary of Southern Company. Prior to the completion of the Merger, Southern Company and Southern Company Gas operated as separate companies. The condensed statement of income herein includes Southern Company Gas' results of operations since July 1, 2016. See Note 12 to the financial statements under "Southern Company – Merger with Southern Company Gas" for additional information regarding the Merger, including certain pro forma results of operations.

A condensed statement of income for the gas business follows:

	Amount 2016 (in millions)
Operating revenues	$ 1,652
Cost of natural gas	613
Cost of other sales	10
Other operations and maintenance	523
Depreciation and amortization	238
Taxes other than income taxes	71
Total operating expenses	1,455
Operating income	197
Earnings from equity method investments	60
Interest expense, net of amounts capitalized	81
Other income (expense), net	14
Income taxes	76
Net income	114
Less: Net income attributable to noncontrolling interests	—
Net Income Attributable to Southern Company Gas	$ 114

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Seasonality of Results
During the period from November through March when natural gas usage and operating revenues are generally higher (Heating Season), more customers are connected to Southern Company Gas' distribution systems, and natural gas usage is higher in periods of colder weather. Occasionally in the summer, operating revenues are impacted due to peak usage by power generators in response to summer energy demands. Southern Company Gas' base operating expenses, excluding cost of natural gas, bad debt expense, and certain incentive compensation costs, are incurred relatively equally over any given year. Thus, operating results can vary significantly from quarter to quarter as a result of seasonality. For July 1, 2016 through December 31, 2016, the percentage of operating revenues and net income generated during the Heating Season (November and December) were 67.1% and 96.5%, respectively.
Other Business Activities
Southern Company's other business activities include the parent company (which does not allocate operating expenses to business units), products and services in the areas of distributed generation, energy efficiency, and utility infrastructure, and investments in leveraged lease projects and telecommunications. These businesses are classified in general categories and may comprise the following subsidiaries: PowerSecure is a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure; Southern Company Holdings, Inc. (Southern Holdings) invests in various projects, including leveraged lease projects; and Southern LINC 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.
On May 9, 2016, Southern Company acquired all of the outstanding stock of PowerSecure for $18.75 per common share in cash, resulting in an aggregate purchase price of $429 million. As a result, PowerSecure became a wholly-owned subsidiary of Southern Company. See Note 12 to the financial statements under "Southern Company – Acquisition of PowerSecure" for additional information.
A condensed statement of income for Southern Company's other business activities follows:

	Amount	Increase (Decrease) from Prior Year	
	2016	2016	2015
	(in millions)		
Operating revenues	$303	$ 256	$ (14)
Cost of other sales	192	192	—
Other operations and maintenance	194	70	29
Depreciation and amortization	31	17	(2)
Taxes other than income taxes	3	1	—
Total operating expenses	420	280	27
Operating income (loss)	(117)	(24)	(41)
Interest expense	305	239	25
Other income (expense), net	(31)	(24)	(18)
Income taxes	(216)	(84)	(56)
Net income (loss)	$(237)	$ (203)	$ (28)

Operating Revenues
Southern Company's non-electric operating revenues for these other business activities increased $256 million, or 544.7%, in 2016 as compared to the prior year. The increase was primarily related to revenues from products and services at PowerSecure, which was acquired on May 9, 2016. Non-electric operating revenues for these other business activities decreased $14 million, or 23.0%, in 2015 as compared to the prior year. The decrease was primarily related to lower operating revenues at Southern Holdings due to higher billings in 2014 related to work performed on a generating plant outage and decreases in revenues at Southern LINC related to lower average per subscriber revenue

and fewer subscribers due to continued competition in the industry.

Cost of Other Sales

Cost of other sales were $192 million in 2016. These costs were primarily related to sales of products and services by PowerSecure, which was acquired on May 9, 2016.

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Other Operations and Maintenance Expenses

Other operations and maintenance expenses for these other business activities increased $70 million, or 56.5%, in 2016 as compared to the prior year. The increase was primarily due to $47 million in operations and maintenance expenses at PowerSecure since the acquisition closed on May 9, 2016 and an increase in parent company expenses of $16 million related to the Merger and the acquisition of PowerSecure. Other operations and maintenance expenses for these other business activities increased $29 million, or 30.5%, in 2015 as compared to the prior year. The increase was primarily due to parent company expenses of $27 million related to the Merger, partially offset by lower operating expenses at Southern Holdings due to work performed on a generating plant outage in 2014.

Other Income (Expense), Net

Other income (expense), net for these other business activities decreased $24 million in 2016 as compared to the prior year. The decrease was primarily due to an increase of $16 million in parent company expenses related to fees associated with the bridge financing for the Merger. Other income (expense), net for these other business activities decreased $18 million in 2015 as compared to the prior year. The decrease was primarily due to parent company expenses of $14 million related to fees associated with bridge financing for the Merger.

Interest Expense

Interest expense for these other business activities increased $239 million, or 362.1%, in 2016 as compared to the prior year primarily due to an increase in outstanding long-term debt at the parent company primarily relating to financing a portion of the purchase price for the Merger. Interest expense for these other business activities increased $25 million, or 61.0%, in 2015 as compared the prior year primarily due to an increase in outstanding long-term debt.

Income Taxes

Income taxes for these other business activities decreased $84 million, or 63.6%, in 2016 as compared to the prior year primarily as a result of changes in pre-tax earnings (losses), partially offset by state income tax benefits realized in 2015. Income taxes for these other business activities decreased $56 million, or 73.7%, in 2015 as compared to the prior year primarily as a result of state income tax benefits realized in 2015 and changes in pre-tax earnings (losses).

Effects of Inflation

The electric operating companies and natural gas distribution utilities are 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. Southern Power is party to long-term contracts reflecting market-based rates, including inflation expectations. Any adverse effect of inflation on Southern Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The four traditional electric operating companies operate as vertically integrated utilities providing electric service to customers within their service territories in the Southeast. The seven natural gas distribution utilities provide service to customers in their service territories in Illinois, Georgia, Virginia, New Jersey, Florida, Tennessee, and Maryland. Prices for electricity provided and natural gas distributed to retail customers are set by state PSCs or other applicable state regulatory agencies under cost-based regulatory principles. Prices for wholesale electricity sales and natural gas distribution, 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. Southern Power continues to focus on long-term PPAs. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Utility Regulation" herein and Note 3 to the financial statements 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 Southern Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Southern Company system's primary businesses of selling electricity and distributing natural gas. These factors include the traditional electric operating companies' and the natural gas distribution utilities' ability to maintain a constructive regulatory environment that allows for the timely recovery of prudently-incurred costs during a time of increasing costs and limited projected demand growth over the next several years. The completion and subsequent operation of the Kemper IGCC and Plant Vogtle Units 3 and 4, as well as other ongoing construction projects, and the profitability of Southern Power's competitive wholesale business and successful additional investments in renewable and other energy projects are other major factors. Current proposals related to potential tax reform legislation are primarily focused on reducing the corporate income tax rate, allowing 100% of capital expenditures to be deducted, and eliminating the interest deduction. The ultimate impact of any tax reform proposals, including any potential changes to the availability or realizability of ITCs and PTCs, is dependent on the final form of any legislation enacted and the related transition rules and cannot be determined at this time, but could have a material impact on Southern Company's financial statements.

Future earnings for the electricity and natural gas businesses will be driven primarily by customer growth. Earnings in the electricity business will also depend upon maintaining and growing sales, considering, among other things, the adoption and/or penetration rates of increasingly energy-efficient technologies, increasing volumes of electronic commerce transactions, and higher multi-family home construction. Earnings for both the electricity and natural gas businesses are subject to a variety of other factors. These factors include weather, competition, new energy contracts with other utilities and other wholesale customers, energy conservation practiced by customers, the use of alternative energy sources by customers, the prices of electricity and natural gas, the price elasticity of demand, and the rate of economic growth or decline in the service territory. In addition, the level of future earnings for the wholesale electric business also depends on numerous factors including regulatory matters, creditworthiness of customers, total electric generating capacity available and related costs, future acquisitions and construction of electric generating facilities, the impact of tax credits from renewable energy projects, and the successful remarketing of capacity as current contracts expire. Demand for electricity and natural gas is primarily driven by economic growth. The pace of economic growth and electricity and natural gas demand may be affected by changes in regional and global economic conditions, which may impact future earnings. In addition, the volatility of natural gas prices has a significant impact on the natural gas distribution utilities' customer rates, long-term competitive position against other energy sources, and the ability of Southern Company Gas' gas marketing services and wholesale gas services businesses to capture value from locational and seasonal spreads. Additionally, changes in commodity prices subject a significant portion of Southern Company Gas' operations to earnings variability.

As part of its ongoing effort to adapt to changing market conditions, Southern Company added several new businesses in 2016, including the acquisitions of Southern Company Gas, PowerSecure, and a 50% interest in the Southern Natural Gas Company, L.L.C. (SNG) pipeline system, as well as continued expansion of Southern Power's renewable energy projects portfolio. Southern Company continues to evaluate and consider a wide array of potential business strategies. These strategies may include business combinations, partnerships, and acquisitions involving other utility or non-utility businesses or properties, disposition of certain assets or businesses, internal restructuring, or some combination thereof. Furthermore, Southern Company may engage in new business ventures that arise from competitive and regulatory changes in the utility industry. Pursuit of any of the above strategies, or any combination thereof, may significantly affect the business operations, risks, and financial condition of Southern Company. See Note 12 to the financial statements for additional information regarding Southern Company's recent acquisition activity.

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 for the traditional electric operating companies and the natural gas distribution utilities or through long-term wholesale agreements for the traditional electric operating companies and Southern Power. 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. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity and natural gas, 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 Southern Company system'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 2016, the traditional electric operating companies had invested approximately $11.9 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $0.5 billion, $0.9 billion, and $1.1 billion for 2016, 2015, and 2014, respectively. The Southern Company system expects that capital expenditures to comply with environmental statutes and regulations will total approximately $2.9 billion from 2017 through 2021, with annual totals of approximately $0.9 billion, $0.7 billion, $0.3 billion, $0.4 billion, and $0.6 billion for 2017, 2018, 2019, 2020, and 2021, respectively. These estimated expenditures do not include any potential capital expenditures that may arise from the EPA's final rules and guidelines or future state plans that would limit CO_2 emissions from existing, new, modified, or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" herein for additional information. The Southern Company system also anticipates costs associated with ash pond closure and ground water monitoring under the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), which are reflected in the Company's ARO liabilities. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

The Southern Company system's ultimate environmental compliance strategy, including potential electric generating 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 time periods over which compliance with regulations is required; individual state implementation of regulations, as applicable; the outcome of any legal challenges to the environmental rules; any additional rulemaking activities in response to legal challenges and court decisions; the cost, availability, and existing inventory of emissions allowances; the impact of future changes in generation and emissions-related technology; the fuel mix of the electric utilities; and environmental remediation requirements. 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.

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 Southern Company system. Although new or revised environmental legislation or regulations could affect many areas of the electric utilities' and natural gas distribution utilities' operations, the full impact of any such changes cannot be determined at this time. Additionally, many 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 and natural gas.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Southern Company system.

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 implementation strategy for the MATS rule included emission controls, retirements, and fuel conversions at affected units within the Southern Company system. All units within the Southern Company system that are subject to the MATS rule completed the measures necessary to achieve compliance with this rule or were retired prior to or during 2016.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone National Ambient Air Quality Standard (NAAQS). In 2008, the EPA adopted a revised eight-hour ozone NAAQS and published its final area designations in 2012. The only area within the traditional electric operating companies' service territory designated as an ozone nonattainment area for the 2008 standard is a 15-county area within metropolitan Atlanta, which on December 23, 2016, the EPA proposed to redesignate to attainment. In October 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 were required to recommend area designations by October 2016, and the only area within the Southern Company system's electric service territory that was proposed for designation is an eight-county area within the Atlanta metropolitan area in Georgia. The EPA is expected to finalize area designations by October 2017.
The EPA regulates fine particulate matter concentrations through an annual and 24-hour average NAAQS, based on standards promulgated in 1997, 2006, and 2012. All areas in which the traditional electric operating companies' generating units are located have been determined by the EPA to be in attainment with those standards.
In 2010, the EPA revised the NAAQS for sulfur dioxide (SO_2), establishing a new one-hour standard. No areas within the Southern Company system's service territory have been designated as nonattainment under this standard. However, in 2015, the EPA finalized a data requirements rule to support final EPA designation decisions for all remaining areas under the SO_2 standard, which could result in nonattainment designations for areas within the Southern Company system's electric service territory. Nonattainment designations could require additional reductions in SO_2 emissions and increased compliance and operational costs.

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In 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 Alabama Power 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. Alabama Power 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 owned by Alabama Power and units owned by SEGCO, which is jointly owned by Alabama Power and Georgia Power.

On July 6, 2011, the EPA finalized the Cross State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide (NO_x) emissions from power plants in two phases – Phase 1 in 2015 and Phase 2 in 2017. The Southern Company system has fossil generation in several states that were subject to the requirements of the 2011 CSAPR, including Alabama, Florida, Georgia, Mississippi, North Carolina, and Texas. On October 26, 2016, the EPA published a final rule that updates the CSAPR ozone season NO_x program, beginning in 2017, and establishes more stringent ozone-season emissions budgets in Alabama, Mississippi, and Texas and removes Florida and North Carolina from the ozone season program. Georgia's ozone season NO_x budget remains unchanged. North Carolina remains in the CSAPR annual SO_2 and NO_x programs, along with Alabama, Georgia, and Texas.

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. On December 14, 2016, the EPA finalized revisions to the regional haze regulations. These regulations establish a deadline of July 31, 2021 for states to submit revised SIPs to the EPA demonstrating reasonable progress toward the statutory goal of achieving natural background conditions by 2064. State implementation of the reasonable progress requirements defined in this final rule could require further reductions in SO_2 or NO_x emissions.

In June 2015, the EPA published a final rule requiring certain states (including Alabama, Florida, Georgia, Mississippi, North Carolina, and Texas) 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), and many states have submitted proposed SIP revisions in response to the rule.

The Southern Company system has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the current and proposed environmental requirements discussed above. 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. The ultimate impact of the eight-hour ozone and SO_2 NAAQS, Alabama opacity rule, CSAPR, regional haze regulations, and SSM rule will depend on various factors, such as implementation, adoption, or other action at the state level, and the outcome of pending and/or future legal challenges, and cannot be determined at this time.

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 2014. The effect of this final rule will depend on the results of additional studies that are currently underway and implementation of the rule by regulators based on site-specific factors. National Pollutant Discharge Elimination System (NPDES) permits issued after July 14, 2018 must include conditions to implement and ensure compliance with the standards and protective measures required by the rule.

In November 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 NPDES 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.

In 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 and natural gas pipelines. The rule became effective in August 2015 but, in October 2015, the U.S. Court of Appeals for the Sixth Circuit issued an order staying implementation of the final rule. The case is held in abeyance pending review by the U.S. Supreme Court of challenges to the U.S. Court of Appeals for the Sixth Circuit's jurisdiction in the case.

These water quality regulations could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions and decisions on infrastructure expansion and improvements. 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. The ultimate impact of these final rules will depend on various factors, such as pending and/or future legal challenges, compliance dates, and implementation of the rules, and cannot be determined at this time.

Coal Combustion Residuals

The traditional electric operating companies currently manage CCR at onsite storage units consisting of landfills and surface impoundments (CCR Units) at 23 current or former electric generating plants. In addition to on-site storage, the traditional electric operating companies also sell a portion of their CCR to third parties for beneficial reuse. Individual states regulate CCR and the states in the Southern Company system's electric service territory each have their own regulatory requirements. Each traditional electric operating company has an inspection program in place to assist in maintaining the integrity of its coal ash surface impoundments.

The CCR Rule became effective in October 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. On December 16, 2016, President Obama signed the Water Infrastructure Improvements for the Nation Act (WIIN Act). The WIIN Act allows states to establish permit programs for implementing the CCR Rule, if the EPA approves the program, and allows for federal permits and EPA enforcement where a state permitting program does not exist. On October 26, 2016, the Georgia Department of Natural Resources approved amendments to its state solid waste regulations to incorporate the requirements of the CCR Rule and establish additional requirements for all of Georgia Power's onsite storage units consisting of landfills and surface impoundments.

Based on current cost estimates for closure and monitoring of ash ponds pursuant to the CCR Rule, Southern Company has recorded incremental AROs related to the CCR Rule. As further analysis is performed, including evaluation of the expected method of compliance, refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, and the determination of timing with respect to compliance activities, the traditional electric operating companies expect to continue to periodically update these estimates. The traditional electric operating companies have posted closure and post-closure care plans to their public websites as required by the CCR Rule; however, the ultimate impact of the CCR Rule will depend on the results of initial and ongoing minimum criteria assessments and the implementation of state or federal permit programs. Southern 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 Southern Company's AROs as of December 31, 2016.

Environmental Remediation

The Southern Company system must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Southern Company system could incur substantial costs to clean up affected sites. The traditional electric operating companies and Southern Company Gas conduct studies to determine the extent of any required cleanup and the Company has recognized in its financial statements the costs to clean up known impacted sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The traditional electric operating companies and the natural gas distribution utilities in Illinois, New Jersey, Georgia, and Florida have each received authority from their respective state PSCs or other applicable state regulatory agencies to recover approved environmental compliance costs through regulatory mechanisms. These regulatory mechanisms are adjusted annually or as necessary within limits approved by the state PSCs or other applicable state regulatory agencies. The traditional electric operating companies and Southern Company Gas may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Global Climate Issues

In October 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 review with the courts. The stay will remain in effect through the resolution of the litigation, including any review by 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 and decisions on infrastructure expansion and improvements. Southern 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 Southern Company system cannot be determined at this time and will depend upon numerous factors, including the outcome of pending legal challenges, including legal challenges filed by the traditional electric operating companies, and any individual state implementation of the EPA's final guidelines in the event the rule is upheld and implemented.

In December 2015, parties to the United Nations Framework Convention on Climate Change – including the United States – adopted 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 tracking progress toward the goals every five years. The ultimate impact of this agreement depends on its implementation by participating countries and cannot be determined at this time.

The EPA's greenhouse gas reporting rule requires annual reporting of greenhouse gas emissions expressed in terms of metric tons of CO_2 equivalent emissions for a company's operational control of facilities. Based on ownership or financial control of facilities, the Southern Company system's 2015 greenhouse gas emissions were approximately 102 million metric tons of CO_2 equivalent. The preliminary estimate of the Southern Company system's 2016 greenhouse gas emissions on the same basis, including the addition of Southern Company Gas, is approximately 99 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

Market-Based Rate Authority

The traditional electric operating companies and Southern Power have 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 electric operating companies and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In April 2015, the FERC issued an order finding that the traditional electric operating companies' and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. The FERC directed the traditional electric operating companies 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 electric operating companies and Southern Power filed a request for rehearing in May 2015 and in June 2015 filed their response with the FERC.

On December 9, 2016, the traditional electric operating companies and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide

adequate alternative mitigation for the traditional electric operating companies' and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. The traditional electric operating companies and Southern Power expect to make a compliance filing within 30 days accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.
The ultimate outcome of these matters cannot be determined at this time.
Southern Company Gas
At December 31, 2016, Southern Company Gas' gas midstream operations was involved in three gas pipeline construction projects with expected capital expenditures of approximately $780 million. These projects, along with Southern Company Gas' existing pipelines, are intended to provide diverse sources of natural gas supplies to customers, resolve current and long-term

supply planning for new capacity, enhance system reliability, and generate economic development in the areas served. One of these projects received FERC approval in August 2016. The remaining projects are pending FERC approval, which is expected to occur in 2017. The ultimate outcome of this matter cannot be determined at this time.

Regulatory Matters

Alabama Power

Alabama Power's revenues from regulated retail operations are collected through various rate mechanisms subject to the oversight of the Alabama PSC. Alabama Power 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 Alabama Power. See Note 3 to the financial statements under "Regulatory Matters – Alabama Power" for additional information regarding Alabama Power's rate mechanisms and accounting orders.

Rate RSE

The Alabama PSC has adopted Rate RSE that provides for periodic annual adjustments based upon Alabama Power'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 Alabama Power's actual retail return is above the allowed WCE range, the excess will be refunded to customers unless otherwise directed by the Alabama PSC; however, there is no provision for additional customer billings should the actual retail return fall below the WCE range.

On December 1, 2016, Alabama Power made its required annual Rate RSE submission to the Alabama PSC of projected data for calendar year 2017. The Rate RSE adjustment was an increase of 4.48%, or $245 million annually, effective January 1, 2017 and includes the performance based adder of 0.07%. Under the terms of Rate RSE, the maximum increase for 2018 cannot exceed 3.52%.

As of December 31, 2016, the 2016 retail return exceeded the allowed WCE range; therefore, Alabama Power established a $73 million Rate RSE refund liability. In accordance with an order issued on February 14, 2017 by the Alabama PSC, Alabama Power was directed to apply the full amount of the refund to reduce the under recovered balance of Rate CNP PPA.

Rate CNP PPA

Alabama Power'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. Alabama Power may also recover retail costs associated with certificated PPAs under Rate CNP PPA. On March 8, 2016, the Alabama PSC issued a consent order that Alabama Power leave in effect the current Rate CNP PPA factor for billings for the period April 1, 2016 through March 31, 2017. No adjustment to Rate CNP PPA is expected in 2017.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, Alabama Power was authorized to eliminate the under recovered balance in Rate CNP PPA at December 31, 2016, which totaled approximately $142 million. As discussed herein under "Rate RSE," Alabama Power will utilize the full amount of its $73 million Rate RSE refund liability to reduce the amount of the Rate CNP PPA under recovery and will reclassify the remaining $69 million to a separate regulatory asset. The amortization of the new regulatory asset through Rate RSE will begin concurrently with the effective date of Alabama Power's next depreciation study, which is expected to occur within the next three to five years. Alabama Power's current depreciation study became effective January 1, 2017.

Rate CNP Compliance

Rate CNP Compliance allows for the recovery of Alabama Power's retail costs associated with laws, regulations, and other such mandates directed at the utility industry involving the environment, security, reliability, safety, sustainability, or similar considerations impacting Alabama Power's facilities or operations. 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. Revenues for Rate CNP Compliance, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in Rate CNP Compliance related operations and maintenance expenses and depreciation generally will have no effect on net income.

On December 6, 2016, the Alabama PSC issued a consent order that Alabama Power leave in effect for 2017 the factors associated with Alabama Power's compliance costs for the year 2016. As stated in the consent order, any under-collected amount for prior years will be deemed recovered before the recovery of any current year amounts. Any under recovered amounts associated with 2017 will be reflected in the 2018 filing.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, Alabama Power is authorized to classify any under recovered balance in Rate CNP Compliance up to approximately $36 million to a separate regulatory asset. The amortization of the new regulatory asset through Rate RSE will begin concurrently with the effective date of Alabama Power's next depreciation study, which is expected to occur within the next three to five years. Alabama Power's current depreciation study became effective January 1, 2017.

Environmental Accounting Order

Based on an order from the Alabama PSC, Alabama Power 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 2016, as part of its environmental compliance strategy, Alabama Power ceased using coal at Plant Greene County Units 1 and 2 (300 MWs representing Alabama Power's ownership interest) and began operating Units 1 and 2 solely on natural gas in June 2016 and July 2016, respectively. As a result, Alabama Power 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 units' remaining useful lives, as established prior to the decision for retirement; therefore, these decisions associated with coal operations had no significant impact on Southern Company's financial statements.

Georgia Power

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

Rate Plans

Pursuant to the terms and conditions of a settlement agreement related to Southern Company's acquisition of Southern Company Gas approved by the Georgia PSC on April 14, 2016, the 2013 ARP will continue in effect until December 31, 2019, and Georgia Power will be required to file its next base rate case by July 1, 2019. Furthermore, through December 31, 2019, Georgia Power and Atlanta Gas Light Company each will retain their respective merger savings, net of transition costs, as defined in the settlement agreement; through December 31, 2022, such net merger savings applicable to each will be shared on a 60/40 basis with their respective customers; thereafter, all merger savings will be retained by customers. See Note 3 to the financial statements under "Regulatory Matters – Georgia Power – Rate Plans" for additional information regarding the 2013 ARP and Note 12 to the financial statements under "Southern Company – Merger with Southern Company Gas" for additional information regarding the Merger.

In accordance with the 2013 ARP, the Georgia PSC approved increases to tariffs effective January 1, 2015 and 2016 as follows: (1) traditional base tariff rates by approximately $107 million and $49 million, respectively; (2) ECCR tariff by approximately $23 million and $75 million, respectively; (3) DSM tariffs by approximately $3 million in each year; and (4) MFF tariff by approximately $3 million and $13 million, respectively, for a total increase in base revenues of approximately $136 million and $140 million, respectively.

Under the 2013 ARP, Georgia Power's retail ROE is set at 10.95% and earnings are evaluated against a retail ROE range of 10.00% to 12.00%. Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by Georgia Power. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. In 2014, Georgia Power's retail ROE exceeded 12.00%, and Georgia Power refunded to retail customers approximately $11 million in 2016, as approved by the Georgia PSC on February 18, 2016. In 2015, Georgia Power's retail ROE was within the allowed retail ROE range. In 2016, Georgia Power's retail ROE exceeded 12.00%, and Georgia Power expects to refund to retail customers approximately $40 million, subject to review and approval by the Georgia PSC. The ultimate outcome of this matter cannot be determined at this time.

Integrated Resource Plan

See "Environmental Matters" herein for additional information regarding proposed and final EPA rules and regulations, including the MATS rule for coal- and oil-fired electric utility steam generating units, revisions to effluent limitations guidelines for steam electric power plants, and additional regulations of CCR and CO_2; and Georgia Power's analysis of the potential costs and benefits of installing the required controls on its fossil generating units in light of these regulations.

On July 28, 2016, the Georgia PSC approved the 2016 IRP including the decertification and retirement of Plant Mitchell Units 3, 4A, and 4B (217 MWs) and Plant Kraft Unit 1 (17 MWs), as well as the decertification of the Intercession City unit (143 MWs total capacity). On August 2, 2016, the Plant Mitchell and Plant Kraft units were retired. On August 31, 2016, Georgia Power sold its 33% ownership interest in the Intercession City unit to Duke Energy Florida, LLC.

Additionally, the Georgia PSC approved Georgia Power's environmental compliance strategy and related expenditures proposed in the 2016 IRP, including measures taken to comply with existing government-imposed environmental mandates, subject to limits on expenditures for Plant McIntosh Unit 1 and Plant Hammond Units 1 through 4.

The Georgia PSC approved the reclassification of the remaining net book value of Plant Mitchell Unit 3 and costs associated with materials and supplies remaining at the unit retirement date to a regulatory asset. Recovery of the unit's net book value will continue through December 31, 2019, as provided in the 2013 ARP. The timing of the recovery of the remaining balance of the unit's net book value as of December 31, 2019 and costs associated with materials and supplies remaining at the unit retirement date was deferred for consideration in Georgia Power's 2019 base rate case.

The Georgia PSC also approved the Renewable Energy Development Initiative to procure an additional 1,200 MWs of renewable resources primarily utilizing market-based prices established through a competitive bidding process with expected in-service dates between 2018 and 2021. Additionally, 200 MWs of self-build capacity for use by Georgia Power was approved, as well as consideration for no more than 200 MWs of capacity as part of a renewable commercial and industrial program.

The Georgia PSC also approved recovery of costs up to $99 million through June 30, 2019 to preserve nuclear as an option at a future generation site in Stewart County, Georgia. The timing of cost recovery will be determined by the Georgia PSC in a future base rate case. The ultimate outcome of this matter cannot be determined at this time.

Storm Damage Recovery

As of December 31, 2016, the balance in Georgia Power's regulatory asset related to storm damage was $206 million. During October 2016, Hurricane Matthew caused significant damage to Georgia Power's transmission and distribution facilities. As of December 31, 2016, Georgia Power had recorded incremental restoration cost related to this hurricane of $121 million, of which approximately $116 million was charged to the storm damage reserve and the remainder was capitalized. Georgia Power is accruing $30 million annually through December 31, 2019, as provided in the 2013 ARP, to the storm damage reserve to cover the operations and maintenance costs of damages from major storms to its transmission and distribution facilities, which is recoverable through base rates. The rate of recovery of storm damage costs after December 31, 2019 is expected to be adjusted in Georgia Power's 2019 base rate case. As a result of this regulatory treatment, costs related to storms are not expected to have a material impact on Southern Company's financial statements. See Note 3 to the financial statements under "Regulatory Matters – Georgia Power – Storm Damage Recovery" for additional information regarding Georgia Power's storm damage reserve.

Gulf Power

Through 2015, long-term non-affiliate capacity sales from Gulf Power's ownership of Plant Scherer Unit 3 (205 MWs) provided the majority of Gulf Power's wholesale earnings. Contract expirations at the end of 2015 and the end of May 2016 related to Plant Scherer Unit 3 wholesale sales did not have a material impact on Southern Company's earnings in 2016. Remaining contract sales from Plant Scherer Unit 3 cover approximately 24% of Gulf Power's ownership of the unit through 2019.

On October 12, 2016, Gulf Power filed a petition (2016 Rate Case) with the Florida PSC requesting an annual increase in retail rates and charges of $106.8 million based on the projected test year of January 1, 2017 through December 31, 2017 and a retail ROE of 11% compared to the current retail ROE of 10.25%. The requested increase includes recovery of the portion of Plant Scherer Unit 3 that has been rededicated to serving retail customers following the contract expirations discussed above. If retail recovery of Plant Scherer Unit 3 is not approved by the Florida PSC in the 2016 Rate Case, Gulf Power may consider an asset sale. The current book value of Gulf Power's ownership of Plant Scherer Unit 3 could exceed market value which could result in a material loss. The Florida PSC is expected to make a decision on the 2016 Rate Case in the second quarter 2017. Gulf Power has requested that the increase in base rates, if approved by the Florida PSC, become effective in July 2017.

On November 2, 2016, the Florida PSC approved Gulf Power's 2017 annual cost recovery clause factors. The fuel and environmental factors include certain costs associated with the ongoing ownership and operation of Plant Scherer Unit 3. The final disposition of these costs, and the related impact on rates, is subject to the Florida PSC's ultimate ruling on whether costs associated with Plant Scherer Unit 3 are recoverable from retail customers, which is expected to be decided in the 2016 Rate Case as discussed previously.

See Note 3 to the financial statements under "Regulatory Matters – Gulf Power – Retail Base Rate Cases" for additional information. The ultimate outcome of these matters cannot be determined at this time.

Southern Company Gas

Natural Gas Cost Recovery

Southern Company Gas has established natural gas cost recovery rates that are approved by the applicable state regulatory agencies in the states in which it serves. Natural gas cost recovery revenues are adjusted for differences in actual recoverable natural gas costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on Southern Company's revenues or net income, but will affect cash flow.

Regulatory Infrastructure Programs

Six of Southern Company Gas' seven natural gas distribution utilities are involved in ongoing capital projects associated with infrastructure improvement programs that have been previously approved by their applicable state regulatory agencies and provide an appropriate return on invested capital. These infrastructure improvement programs are designed to update or expand the natural gas distribution systems of the natural gas distribution utilities to improve reliability and meet operational flexibility and growth. Initial program lengths range from four to 10 years, with the longest set to expire in 2025. The total expected investment under these programs for 2017 is $590 million.

On February 21, 2017, the Georgia PSC approved a rate adjustment mechanism for Atlanta Gas Light that included the 2017 capital investment associated with a four-year extension of one of its existing infrastructure programs, with a total additional investment of $177 million through 2020. In addition, Elizabethtown Gas currently has a proposed infrastructure improvement program pending approval by the New Jersey Board of Public Utilities requesting to invest more than $1.1 billion through 2027.

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

Renewables

In accordance with the September 2015 Alabama PSC order approving up to 500 MWs of renewable projects, Alabama Power has entered into agreements to purchase power from and to build 89 MWs of renewable generation sources. The terms of the agreements permit Alabama Power to use the energy and retire the associated renewable energy credits (REC) in service of its customers or to sell RECs, separately or bundled with energy.

In 2014, the Georgia PSC approved Georgia Power's application for the certification of two PPAs executed in 2013 for the purchase of energy from two wind farms in Oklahoma with capacity totaling 250 MWs that began in 2016 and have 20-year terms.

As part of the Georgia Power Advanced Solar Initiative (ASI), in 2014, the Georgia PSC approved PPAs executed since April 2015 for the purchase of energy from 555 MWs of solar capacity that began in 2015 and 2016 and have terms ranging from 20 to 30 years. As a result of certain acquisitions by Southern Power, 249 MWs of this contracted capacity is being provided from solar facilities owned by Southern Power through five PPAs that began in 2016. Ownership of any associated REC is specified in each respective PPA. The party that owns the RECs retains the right to use them.

In 2014, the Georgia PSC approved Georgia Power's request to build, own, and operate 30-MW solar generation facilities at three U.S. Army bases and one U.S. Navy base by the end of 2016. One of the four solar generation facilities began commercial operation in December 2015 and the remaining three began in the fourth quarter 2016. In December 2015, the Georgia PSC approved Georgia Power's request to build, own, and operate a 31-MW solar generation facility at a U.S. Marine Corps base that is expected to begin commercial operation by summer 2017 and a 15-MW solar generation facility at a yet-to-be-determined U.S. military base. The ultimate outcome of this matter cannot be determined at this time.

Two PPAs for biomass generation capacity of 58 MWs each were executed in June 2015 and November 2015 and are expected to begin in 2019.

See "Georgia Power – Integrated Resource Plan" herein for additional information on Georgia Power's renewables.

In April 2015, the Florida PSC approved Gulf Power's three energy purchase agreements totaling 120 MWs of utility-scale solar generation located at three military installations in northwest Florida. Purchases under these solar agreements are expected to begin by the summer of 2017.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Company and Subsidiary Companies 2016 Annual Report

The Florida PSC issued a final approval order on Gulf Power's Community Solar Pilot Program on April 15, 2016. The program will offer Gulf Power's customers an opportunity to voluntarily contribute to the construction and operation of a solar photovoltaic facility with electric generating capacity of up to 1 MW through annual subscriptions. The energy generated from the solar facility is expected to provide power to all of Gulf Power's customers.

On November 29, 2016, the Florida PSC approved Gulf Power's energy purchase agreement for up to 94 MWs of additional wind generation in central Oklahoma. Purchases under this agreement will be for energy only and will be recovered through Gulf Power's fuel cost recovery clause.

In November 2015, the Mississippi PSC issued orders approving three solar facilities for a combined total of approximately 105 MWs. Mississippi Power will purchase all of the energy produced by the solar facilities for the 25-year term under each of the three PPAs. The projects are expected to be in service by the second quarter 2017 and the resulting energy purchases are expected to be recovered through Mississippi Power's fuel cost recovery mechanism. Mississippi Power may retire the RECs generated on behalf of its customers or sell the RECs, separately or bundled with energy, to third parties.

See Note 12 to the financial statements for information on Southern Power's renewables activities.

Fuel Cost Recovery

The traditional electric operating companies each have established fuel cost recovery rates approved by their respective state PSCs. Fuel cost recovery revenues are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on Southern Company's revenues or net income, but will affect cash flow. The traditional electric operating companies continuously monitor their under or over recovered fuel cost balances and make appropriate filings with their state PSCs to adjust fuel cost recovery rates as necessary.

See Note 1 to the financial statements under "Revenues" and Note 3 to the financial statements under "Regulatory Matters – Alabama Power – Rate ECR" and "Regulatory Matters – Georgia Power – Fuel Cost Recovery" for additional information.

Construction Program

Overview

The subsidiary companies of Southern Company are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. The Southern Company system intends to continue its strategy of developing and constructing new electric generating facilities, adding environmental modifications to certain existing units, expanding the electric transmission and distribution systems, and updating and expanding the natural gas distribution systems. For the traditional electric operating companies, major generation construction projects are subject to state PSC approval in order to be included in retail rates. While Southern Power generally constructs and acquires generation assets covered by long-term PPAs, any uncontracted capacity could negatively affect future earnings. Southern Company Gas is engaged in various infrastructure improvement programs designed to update or expand the natural gas distribution systems of the natural gas distribution utilities to improve reliability and meet operational flexibility and growth. The natural gas distribution utilities recover their investment and a return associated with these infrastructure programs through their regulated rates. The Southern Company system's construction program is currently estimated to total approximately $9.1 billion, $8.2 billion, $7.3 billion, $6.9 billion, and $6.4 billion for 2017, 2018, 2019, 2020, and 2021, respectively.

The two largest construction projects currently underway in the Southern Company system are Plant Vogtle Units 3 and 4 (45.7% ownership interest by Georgia Power in the two units, each with approximately 1,100 MWs) and Mississippi Power's Kemper IGCC. See Note 3 to the financial statements under "Regulatory Matters – Georgia Power – Nuclear Construction" and "Integrated Coal Gasification Combined Cycle" for additional information. See Note 12 to the financial statements under "Southern Power – Construction Projects" for additional information about costs relating

to Southern Power's acquisitions that involve construction of renewable energy facilities. See Note 3 to the financial statements under "Regulatory Matters – Southern Company Gas – Regulatory Infrastructure Programs" for additional information regarding infrastructure improvement programs at the natural gas distribution utilities.
Also see FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein for additional information regarding Southern Company's capital requirements for its subsidiaries' construction programs.
Integrated Coal Gasification Combined Cycle
Mississippi Power continues to progress toward completing the construction and start-up of the Kemper IGCC, which was approved by the Mississippi PSC in the 2010 CPCN proceedings, subject to a construction cost cap of $2.88 billion, net of $245 million of Initial DOE Grants and excluding the Cost Cap Exceptions. The current cost estimate for the Kemper IGCC in total is

approximately $6.99 billion, which includes approximately $5.64 billion of costs subject to the construction cost cap and is net of the $137 million in additional grants from the DOE received on April 8, 2016 (Additional DOE Grants), which are expected to be used to reduce future rate impacts to customers. Mississippi Power does not intend to seek any rate recovery for any related costs that exceed the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions. Southern Company recorded pre-tax charges to income for revisions to the cost estimate subject to the construction cost cap totaling $348 million ($215 million after tax), $365 million ($226 million after tax), and $868 million ($536 million after tax) in 2016, 2015, and 2014, respectively. Since 2013, in the aggregate, Southern Company has incurred charges of $2.76 billion ($1.71 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through December 31, 2016. The current cost estimate includes costs through March 15, 2017.

In addition to the current construction cost estimate, Mississippi Power is identifying potential improvement projects that ultimately may be completed subsequent to placing the remainder of the Kemper IGCC in service. If completed, such improvement projects would be expected to enhance plant performance, safety, and/or operations. As of December 31, 2016, approximately $12 million of related potential costs has been included in the estimated loss on the Kemper IGCC. Other projects have yet to be fully evaluated, have not been included in the current cost estimate, and may be subject to the $2.88 billion cost cap. Any further changes in the estimated costs of the Kemper IGCC subject to the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions, will be reflected in Southern Company's statements of income and these changes could be material.

The expected completion date of the Kemper IGCC at the time of the Mississippi PSC's approval in 2010 was May 2014. The combined cycle and the associated common facilities portion of the Kemper IGCC were placed in service in August 2014. The remainder of the plant, including the gasifiers and the gas clean-up facilities, represents first-of-a-kind technology. The initial production of syngas began on July 14, 2016 for gasifier "B" and on September 13, 2016 for gasifier "A." Mississippi Power achieved integrated operation of both gasifiers on January 29, 2017, including the production of electricity from syngas in both combustion turbines. Mississippi Power subsequently completed a brief outage to repair and make modifications to further improve the plant's ability to achieve sustained operations sufficient to support placing the plant in service for customers. Efforts to reach sustained operation of both gasifiers and production of electricity from syngas in both combustion turbines are in process. The plant has produced and captured CO_2, and has produced sulfuric acid and ammonia, all of acceptable quality under the related off-take agreements. On February 20, 2017, Mississippi Power determined gasifier "B," which has been producing syngas over 60% of the time since early November 2016, requires an outage to remove ash deposits from its ash removal system. Gasifier "A" and combustion turbine "A" are expected to remain in operation, producing electricity from syngas, as well as producing chemical by-products. As a result, Mississippi Power currently expects the remainder of the Kemper IGCC, including both gasifiers, will be placed in service by mid-March 2017.

Upon placing the remainder of the plant in service, Mississippi Power will be primarily focused on completing the regulatory cost recovery process. In December 2015, the Mississippi PSC issued an order, based on a stipulation between Mississippi Power and the MPUS, authorizing rates that provide for the recovery of approximately $126 million annually related to Kemper IGCC assets previously placed in service.

On August 17, 2016, the Mississippi PSC established a discovery docket to manage all filings related to Kemper IGCC prudence issues. On October 3, 2016 and November 17, 2016, Mississippi Power made filings in this docket including a review and explanation of differences between the Kemper IGCC project estimate set forth in the 2010 CPCN proceedings and the most recent Kemper IGCC project estimate, as well as comparisons of current cost estimates and current expected plant operational parameters to the estimates presented in the 2010 CPCN proceedings for the first five years after the Kemper IGCC is placed in service. Compared to amounts presented in the 2010 CPCN proceedings, operations and maintenance expenses have increased an average of $105 million annually and maintenance capital has increased an average of $44 million annually for the first full five years of operations for the

Kemper IGCC. Additionally, while the current estimated operational availability estimates reflect ultimate results similar to those presented in the 2010 CPCN proceedings, the ramp up period for the current estimates reflects a lower starting point and a slower escalation rate.

In the fourth quarter 2016, as a part of the Integrated Resource Plan process, the Southern Company system completed its regular annual updated fuel forecast, the 2017 Annual Fuel Forecast. This updated fuel forecast reflected significantly lower long-term estimated costs for natural gas than were previously projected. As a result of the updated long-term natural gas forecast, as well as the revised operating expense projections reflected in the discovery docket filings, on February 21, 2017, Mississippi Power filed an updated project economic viability analysis of the Kemper IGCC as required under the 2012 MPSC CPCN Order. The project economic viability analysis measures the life cycle economics of the Kemper IGCC compared to feasible alternatives, natural gas combined cycle generating units, under a variety of scenarios and considering fuel, operating and capital costs, and operating characteristics, as well as federal and state taxes and incentives. The reduction in the projected long-term natural gas prices in the

2017 Annual Fuel Forecast and, to a lesser extent, the increase in the estimated Kemper IGCC operating costs, negatively impact the updated project economic viability analysis.

After the remainder of the plant is placed in service, AFUDC equity of approximately $11 million per month will no longer be recorded in income, and Mississippi Power expects to incur approximately $25 million per month in depreciation, taxes, operations and maintenance expenses, interest expense, and regulatory costs in excess of current rates. Mississippi Power expects to file a request for authority from the Mississippi PSC and the FERC to defer all Kemper IGCC costs incurred after the in-service date that cannot be capitalized, are not included in current rates, and are not required to be charged against earnings as a result of the $2.88 billion cost cap until such time as the Mississippi PSC completes its review and includes the resulting allowable costs in rates. In the event that the Mississippi PSC does not grant Mississippi Power's request for an accounting order, these monthly expenses will be charged to income as incurred and will not be recoverable through rates. The ultimate outcome of this matter cannot now be determined but could have a material impact on Southern Company's result of operations, financial condition, and liquidity.

Mississippi Power is required to file a rate case to address Kemper IGCC cost recovery by June 3, 2017 (2017 Rate Case). Costs incurred through December 31, 2016 totaled $6.73 billion, net of the Initial and Additional DOE Grants. Of this total, $2.76 billion of costs has been recognized through income as a result of the $2.88 billion cost cap, $0.83 billion is included in retail and wholesale rates for the assets in service, and the remainder will be the subject of the 2017 Rate Case to be filed with the Mississippi PSC and expected subsequent wholesale Municipal and Rural Associations rate filing with the FERC. Mississippi Power continues to believe that all costs related to the Kemper IGCC have been prudently incurred in accordance with the requirements of the 2012 MPSC CPCN Order. Mississippi Power also recognizes significant areas of potential challenge during future regulatory proceedings (and any subsequent, related legal challenges) exist. As described further herein, these challenges include, but are not limited to, prudence issues associated with capital costs, financing costs (AFUDC), and future operating costs, net of chemical revenues; potential operating parameters; income tax issues; costs deferred as regulatory assets; and the 15% portion of the project previously contracted to SMEPA.

Although the 2017 Rate Case has not yet been filed and is subject to future developments with either the Kemper IGCC or the Mississippi PSC, consistent with its approach in the 2013 and 2015 rate proceedings in accordance with the law passed in 2013 authorizing multi-year rate plans, Mississippi Power is developing both a traditional rate case requesting full cost recovery of the $3.31 billion (net of $137 million in Additional DOE Grants) not currently in rates and a rate mitigation plan that together represent Mississippi Power's probable filing strategy. Mississippi Power also expects that timely resolution of the 2017 Rate Case will likely require a negotiated settlement agreement. In the event an agreement acceptable to both Mississippi Power and the MPUS (and other parties) can be negotiated and ultimately approved by the Mississippi PSC, it is reasonably possible that full regulatory recovery of all Kemper IGCC costs will not occur. The impact of such an agreement on Southern Company's financial statements would depend on the method, amount, and type of cost recovery ultimately excluded. Certain costs, including operating costs, would be recorded to income in the period incurred, while other costs, including investment-related costs, would be charged to income when it is probable they will not be recovered and the amounts can be reasonably estimated. In the event an agreement acceptable to the parties cannot be reached, Mississippi Power intends to fully litigate its request for full recovery through the Mississippi PSC regulatory process and any subsequent legal challenges.

Mississippi Power has evaluated various scenarios in connection with its processes to prepare the 2017 Rate Case and has recognized an additional $80 million charge to income, which is the estimated minimum probable amount of the $3.31 billion of Kemper IGCC costs not currently in rates that would not be recovered under the probable rate mitigation plan to be filed by June 3, 2017. Given the variety of potential scenarios and the uncertainty of the outcome of future regulatory proceedings with the Mississippi PSC (and any subsequent related legal challenges), the ultimate outcome of these matters cannot now be determined but could result in further charges that could have a material impact on Southern Company's results of operations, financial condition, and liquidity.

Southern Company and Mississippi Power are defendants in various lawsuits that allege improper disclosure about the Kemper IGCC, as discussed below under "Litigation." In addition, the SEC is conducting a formal investigation of Southern Company and Mississippi Power concerning the estimated costs and expected in-service date of the Kemper IGCC. Southern Company believes the investigation is focused primarily on periods subsequent to 2010 and on accounting matters, disclosure controls and procedures, and internal controls over financial reporting associated with the Kemper IGCC. See "Other Matters" herein for additional information.

The ultimate outcome of these matters cannot be determined at this time. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

Litigation

On April 26, 2016, a complaint against Mississippi Power was filed in Harrison County Circuit Court (Circuit Court) by Biloxi Freezing & Processing Inc., Gulfside Casino Partnership, and John Carlton Dean, which was amended and refiled on July 11, 2016 to include, among other things, Southern Company as a defendant. On August 12, 2016, Southern Company and Mississippi Power removed the case to the U.S. District Court for the Southern District of Mississippi. The plaintiffs filed a request to remand the case back to state court, which was granted on November 17, 2016. The individual plaintiff, John Carlton Dean, alleges that Mississippi Power and Southern Company violated the Mississippi Unfair Trade Practices Act. All plaintiffs have alleged that Mississippi Power and Southern Company concealed, falsely represented, and failed to fully disclose important facts concerning the cost and schedule of the Kemper IGCC and that these alleged breaches have unjustly enriched Mississippi Power and Southern Company. The plaintiffs seek unspecified actual damages and punitive damages; ask the Circuit Court to appoint a receiver to oversee, operate, manage, and otherwise control all affairs relating to the Kemper IGCC; ask the Circuit Court to revoke any licenses or certificates authorizing Mississippi Power or Southern Company to engage in any business related to the Kemper IGCC in Mississippi; and seek attorney's fees, costs, and interest. The plaintiffs also seek an injunction to prevent any Kemper IGCC costs from being charged to customers through electric rates. On December 7, 2016, Southern Company filed motions to dismiss.

On June 9, 2016, Treetop Midstream Services, LLC (Treetop) and other related parties filed a complaint against Mississippi Power, Southern Company, and SCS in the state court in Gwinnett County, Georgia. The complaint relates to the cancelled CO_2 contract with Treetop and alleges fraudulent misrepresentation, fraudulent concealment, civil conspiracy, and breach of contract on the part of Mississippi Power, Southern Company, and SCS and seeks compensatory damages of $100 million, as well as unspecified punitive damages. Southern Company, Mississippi Power, and SCS have moved to compel arbitration pursuant to the terms of the CO_2 contract.

Southern Company believes these legal challenges have no merit; however, an adverse outcome in these proceedings could have an impact on Southern Company's results of operations, financial condition, and liquidity. Southern Company will vigorously defend itself in these matters, and the ultimate outcome of these matters cannot be determined at this time.

Nuclear Construction

In 2008, Georgia Power, acting for itself and as agent for Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia (Dalton), acting by and through its Board of Water, Light, and Sinking Fund Commissioners, doing business as Dalton Utilities (collectively, Vogtle Owners), entered into an agreement with a consortium consisting of Westinghouse and Stone & Webster, Inc., which was subsequently acquired by Westinghouse and changed its name to WECTEC Global Project Services Inc. (WECTEC) (Westinghouse and WECTEC, collectively, Contractor), pursuant to which the Contractor agreed to design, engineer, procure, construct, and test two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities at Plant Vogtle (Vogtle 3 and 4 Agreement).

Under the terms of the Vogtle 3 and 4 Agreement, the Vogtle Owners agreed to pay a purchase price subject to certain price escalations and adjustments, including fixed escalation amounts and index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. The Vogtle 3 and 4 Agreement also provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees, subject to an aggregate cap of 10% of the contract price, or approximately $920 million to $930 million. In addition, the Vogtle 3 and 4 Agreement provides for limited cost sharing by the Vogtle Owners for Contractor costs under certain conditions (which Georgia Power has not been notified have occurred) with maximum additional capital costs under this provision attributable to Georgia Power (based on Georgia Power's ownership interest) of approximately $114 million. Each Vogtle Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Contractor under the Vogtle 3 and 4 Agreement.

Georgia Power's proportionate share is 45.7%. In the event of certain credit rating downgrades of any Vogtle Owner, such Vogtle Owner will be required to provide a letter of credit or other credit enhancement.

Certain obligations of Westinghouse have been guaranteed by Toshiba Corporation (Toshiba), Westinghouse's parent company. In the event of certain credit rating downgrades of Toshiba, Westinghouse is required to provide letters of credit or other credit enhancement. In December 2015, Toshiba experienced credit rating downgrades and Westinghouse provided the Vogtle Owners with $920 million of letters of credit. These letters of credit remain in place in accordance with the terms of the Vogtle 3 and 4 Agreement.

On February 14, 2017, Toshiba announced preliminary earnings results for the period ended December 31, 2016, which included a substantial goodwill impairment charge at Westinghouse attributed to increased cost estimates to complete its U.S. nuclear projects, including Plant Vogtle Units 3 and 4. Toshiba also warned that it will likely be in a negative equity position as a result of the charges. At the same time, Toshiba reaffirmed its commitment to its U.S. nuclear projects with implementation of management changes and increased oversight. An inability or failure by the Contractor to perform its obligations under the Vogtle 3 and 4 Agreement could have a material impact on the construction of Plant Vogtle Units 3 and 4. Under the terms of the Vogtle 3 and 4 Agreement, the Contractor does not have a right to terminate the Vogtle 3 and 4 Agreement for convenience. The Contractor may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including certain Vogtle Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Vogtle Owners, Vogtle Owner insolvency, and certain other events. In the event of an abandonment of work by the Contractor, the maximum liability of the Contractor under the Vogtle 3 and 4 Agreement is increased significantly, but remains subject to limitations. The Vogtle Owners may terminate the Vogtle 3 and 4 Agreement at any time for convenience, provided that the Vogtle Owners will be required to pay certain termination costs.

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4 with a certified capital cost of $4.418 billion. In addition, in 2009 the Georgia PSC approved inclusion of the Plant Vogtle Units 3 and 4 related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows Georgia Power to recover financing costs for nuclear construction projects certified by the Georgia PSC. Financing costs are recovered on all applicable certified costs through annual adjustments to the NCCR tariff by including the related CWIP accounts in rate base during the construction period. The Georgia PSC approved an NCCR tariff of $368 million for 2014, as well as increases to the NCCR tariff of approximately $27 million and $19 million effective January 1, 2015 and 2016, respectively.

Georgia Power is required to file semi-annual Vogtle Construction Monitoring (VCM) reports with the Georgia PSC by February 28 and August 31 each year. In accordance with the 2009 certification order, Georgia Power requested amendments to the Plant Vogtle Units 3 and 4 certificate in both the February 2013 (eighth VCM) and February 2015 (twelfth VCM) filings, when projected construction capital costs to be borne by Georgia Power increased by 5% above the certified costs and estimated in-service dates were extended. In October 2013, the Georgia PSC approved a stipulation (2013 Stipulation) between Georgia Power and the Georgia PSC Staff to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate until the completion of Plant Vogtle Unit 3 or earlier if deemed appropriate by the Georgia PSC and Georgia Power. In April 2015, the Georgia PSC recognized that the certified cost and the 2013 Stipulation did not constitute a cost recovery cap and deemed the amendment requested in the February 2015 filing unnecessary and withdrawn until the completion of construction of Plant Vogtle Unit 3 consistent with the 2013 Stipulation.

On December 31, 2015, Westinghouse and the Vogtle Owners entered into a definitive settlement agreement (Contractor Settlement Agreement) to resolve disputes between the Vogtle Owners and the Contractor under the Vogtle 3 and 4 Agreement, including litigation that was pending in the U.S. District Court for the Southern District of Georgia (Vogtle Construction Litigation). Effective December 31, 2015, Georgia Power, acting for itself and as agent for the other Vogtle Owners, and the Contractor entered into an amendment to the Vogtle 3 and 4 Agreement to implement the Contractor Settlement Agreement. The Contractor Settlement Agreement and the related amendment to the Vogtle 3 and 4 Agreement (i) restrict the Contractor's ability to seek further increases in the contract price by clarifying and limiting the circumstances that constitute nuclear regulatory changes in law; (ii) provide for enhanced dispute resolution procedures; (iii) revise the guaranteed substantial completion dates to June 30, 2019 for Unit 3 and June 30, 2020 for Unit 4; (iv) provide that delay liquidated damages will commence if the nuclear fuel loading date for each unit does not occur by December 31, 2018 for Unit 3 and December 31, 2019 for Unit 4; and (v) provide that Georgia Power, based on its ownership interest, will pay to the Contractor and capitalize to the project cost approximately $350 million, of which approximately $263 million had been paid as of December 31, 2016. In addition, the Contractor Settlement Agreement provides for the resolution of other open existing items relating to the scope of the project under the Vogtle 3 and 4 Agreement, including cyber security, for which costs are reflected in Georgia Power's current in-service forecast of $5.440 billion. Further, as part of the settlement and Westinghouse's acquisition of WECTEC: (i) Westinghouse engaged Fluor Enterprises, Inc., a subsidiary of Fluor Corporation, as a new construction subcontractor and (ii) the Vogtle Owners, Chicago Bridge & Iron Co, N.V., and The Shaw Group Inc. entered into mutual releases of any and all claims arising out of events or circumstances in connection with the construction of Plant Vogtle Units 3 and 4 that occurred on or before the date of the Contractor Settlement Agreement. On January 5, 2016, the Vogtle Construction Litigation was dismissed with prejudice.

On December 20, 2016, the Georgia PSC voted to approve a settlement agreement (Vogtle Cost Settlement Agreement) resolving the following prudence matters: (i) none of the $3.3 billion of costs incurred through December 31, 2015 and reflected in the fourteenth VCM report will be disallowed from rate base on the basis of imprudence; (ii) the Contractor Settlement Agreement is reasonable and prudent and none of the amounts paid or to be paid pursuant to the Contractor Settlement Agreement should be disallowed from rate base on the basis of imprudence; (iii) financing costs on verified and approved capital costs will be deemed prudent provided they are incurred prior to December 31, 2019 and December 31, 2020 for Plant Vogtle Units 3 and 4, respectively; and (iv) (a) the in-service capital cost forecast will be adjusted to $5.680 billion (Revised Forecast), which includes a contingency of $240 million above Georgia Power's current forecast of $5.440 billion, (b) capital costs incurred up to the

Revised Forecast will be presumed to be reasonable and prudent with the burden of proof on any party challenging such costs, and (c) Georgia Power would have the burden to show that any capital costs above the Revised Forecast are reasonable and prudent. Under the terms of the Vogtle Cost Settlement Agreement, the certified in-service capital cost for purposes of calculating the NCCR tariff will remain at $4.418 billion. Construction capital costs above $4.418 billion will accrue AFUDC through the date each unit is placed in service. The ROE used to calculate the NCCR tariff was reduced from 10.95% (the ROE rate setting point authorized by the Georgia PSC in the 2013 ARP) to 10.00% effective January 1, 2016. For purposes of the AFUDC calculation, the ROE on costs between $4.418 billion and $5.440 billion will also be 10.00% and the ROE on any amounts above $5.440 billion would be Georgia Power's average cost of long-term debt. If the Georgia PSC adjusts Georgia Power's ROE rate setting point in a rate case prior to Plant Vogtle Units 3 and 4 being placed into retail rate base, then the ROE for purposes of calculating both the NCCR tariff and AFUDC will likewise be 95 basis points lower than the revised ROE rate setting point. If Plant Vogtle Units 3 and 4 are not placed in service by December 31, 2020, then (i) the ROE for purposes of calculating the NCCR tariff will be reduced an additional 300 basis points, or $8 million per month, and may, at the Georgia PSC's discretion, be accrued to be used for the benefit of customers, until such time as the units are placed in service and (ii) the ROE used to calculate AFUDC will be Georgia Power's average cost of long-term debt.

Under the terms of the Vogtle Cost Settlement Agreement, Plant Vogtle Units 3 and 4 will be placed into retail rate base on December 31, 2020 or when placed in service, whichever is later. The Georgia PSC will determine for retail ratemaking purposes the process of transitioning Plant Vogtle Units 3 and 4 from a construction project to an operating plant no later than Georgia Power's base rate case required to be filed by July 1, 2019.

The Georgia PSC has approved fifteen VCM reports covering the periods through June 30, 2016, including construction capital costs incurred, which through that date totaled $3.7 billion. Georgia Power expects to file the sixteenth VCM report, covering the period from July 1 through December 31, 2016, requesting approval of $222 million of construction capital costs incurred during that period, with the Georgia PSC by February 28, 2017. Georgia Power's CWIP balance for Plant Vogtle Units 3 and 4 was approximately $3.9 billion as of December 31, 2016, and Georgia Power had incurred $1.3 billion in financing costs through December 31, 2016.

As of December 31, 2016, Georgia Power had borrowed $2.6 billion related to Plant Vogtle Units 3 and 4 costs through a loan guarantee agreement between Georgia Power and the DOE and a multi-advance credit facility among Georgia Power, the DOE, and the FFB. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information, including applicable covenants, events of default, and mandatory prepayment events.

There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4 at the federal and state level and additional challenges may arise as construction proceeds. Processes are in place that are designed to assure compliance with the requirements specified in the Westinghouse Design Control Document and the combined construction and operating licenses, including inspections by Southern Nuclear and the NRC that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the NRC. Various design and other licensing-based compliance matters, including the timely resolution of Inspections, Tests, Analyses, and Acceptance Criteria and the related approvals by the NRC, may arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs either to the Vogtle Owners or the Contractor or to both.

In addition to Toshiba's reaffirmation of its commitment, the Contractor provided Georgia Power with revised forecasted in-service dates of December 2019 and September 2020 for Plant Vogtle Units 3 and 4, respectively. Georgia Power is currently reviewing a preliminary summary schedule supporting these dates that ultimately must be reconciled to a detailed integrated project schedule. As construction continues, the risk remains that challenges with

Contractor performance including labor productivity, fabrication, delivery, assembly, and installation of plant systems, structures, and components, or other issues could arise and may further impact project schedule and cost. Georgia Power expects the Contractor to employ mitigation efforts and believes the Contractor is responsible for any related costs under the Vogtle 3 and 4 Agreement. Georgia Power estimates its financing costs for Plant Vogtle Units 3 and 4 to be approximately $30 million per month, with total construction period financing costs of approximately $2.5 billion. Additionally, Georgia Power estimates its owner's costs to be approximately $6 million per month, net of delay liquidated damages.

The revised forecasted in-service dates are within the timeframe contemplated in the Vogtle Cost Settlement Agreement and would enable both units to qualify for production tax credits the IRS has allocated to each of Plant Vogtle Units 3 and 4, which require the applicable unit to be placed in service before 2021. The net present value of the production tax credits is estimated at approximately $400 million per unit.

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

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

Income Tax Matters

Bonus Depreciation

In December 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. Bonus depreciation was extended for qualified property placed in service through 2020. The PATH Act allows for 50% bonus depreciation for 2015 through 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 bonus depreciation included in the PATH Act is expected to result in approximately $1.3 billion of positive cash flows for the 2016 tax year, which was not all realized in 2016 due to a projected consolidated net operating loss (NOL) for Southern Company. Approximately $1.2 billion of positive cash flows is expected to result from bonus depreciation for the 2017 tax year, but may not all be realized in 2017 due to additional NOL projections for the 2017 tax year. As a result of the schedule extension for the Kemper IGCC, approximately $370 million of the 2017 benefit is dependent upon placing the remainder of the Kemper IGCC in service by December 31, 2017. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" and Note 5 to the financial statements under "Current and Deferred Income Taxes – Net Operating Loss" for additional information. The ultimate outcome of this matter cannot be determined at this time.

Tax Credits

The PATH Act allows for 30% ITC for solar projects that commence construction by December 31, 2019; 26% ITC for solar projects that commence construction in 2020; 22% ITC for solar projects that commence construction in 2021; and a permanent 10% ITC for solar projects that commence construction on or after January 1, 2022. In addition, the PATH Act extended the PTC for wind projects with a phase out that allows for 100% PTC for wind projects that commenced construction in 2016; 80% PTC for wind projects that commence construction in 2017; 60% PTC for wind projects that commence construction in 2018; and 40% PTC for wind projects that commence construction in 2019. The Company has received ITCs and PTCs in connection with investments in solar, wind, and biomass facilities primarily at Southern Power and Georgia Power. See Note 1 to the financial statements under "Income and Other Taxes" and Note 5 to the financial statements under "Current and Deferred Income Taxes – Tax Credit Carryforwards" for additional information regarding utilization and amortization of credits and the tax benefit related to basis differences.

Section 174 Research and Experimental Deduction

Southern Company reflected deductions for research and experimental (R&E) expenditures related to the Kemper IGCC in its federal income tax calculations since 2013 and filed amended federal income tax returns for 2008 through 2013 to also include such deductions. In December 2016, Southern Company and the IRS reached a proposed settlement, subject to approval of the U.S. Congress Joint Committee on Taxation, resolving a methodology for these deductions. Due to the uncertainty related to this tax position, Southern Company had unrecognized tax benefits associated with these R&E deductions totaling approximately $464 million as of December 31, 2016. See "Bonus Depreciation" herein and Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information. This matter is expected to be resolved in the next 12 months; however, the ultimate outcome of this matter cannot be determined at this time.

Other Matters

Southern Company and its subsidiaries are involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Southern Company and its subsidiaries are subject to certain claims and legal actions arising in the ordinary course of business. The business activities of Southern Company's subsidiaries 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 Southern Company and its subsidiaries 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 Southern 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.

On January 20, 2017, a purported securities class action complaint was filed against Southern Company and certain of its and Mississippi Power's officers in the U.S. District Court for the Northern District of Georgia, Atlanta Division, by Monroe County Employees' Retirement System on behalf of all persons who purchased shares of Southern Company's common stock between April 25, 2012 and October 29, 2013. The complaint alleges that Southern Company and certain of its and Mississippi Power's officers made materially false and misleading statements regarding the Kemper IGCC in violation of certain provisions under the Securities Exchange Act of 1934, as amended. The complaint seeks, among other things, compensatory damages and litigation costs and attorneys' fees. Southern Company believes this legal challenge has no merit; however, an adverse outcome in this proceeding could have an impact on Southern Company's results of operations, financial condition, and liquidity. Southern Company will vigorously defend itself in this matter, and the ultimate outcome of this matter cannot be determined at this time.

The SEC is conducting a formal investigation of Southern Company and Mississippi Power concerning the estimated costs and expected in-service date of the Kemper IGCC. Southern Company believes the investigation is focused primarily on periods subsequent to 2010 and on accounting matters, disclosure controls and procedures, and internal controls over financial reporting associated with the Kemper IGCC. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" herein for additional information on the Kemper IGCC estimated construction costs and expected in-service date. The ultimate outcome of this matter cannot be determined at this time; however, it is not expected to have a material impact on the financial statements of Southern Company.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Southern Company prepares its consolidated 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 Southern 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.

Utility Regulation

Southern Company's traditional electric operating companies and natural gas distribution utilities, which collectively comprised approximately 91% of Southern Company's total operating revenues for 2016, are subject to retail regulation by their respective state PSCs or other applicable state regulatory agencies and wholesale regulation by the FERC. These regulatory agencies set the rates the traditional electric operating companies and the natural gas distribution utilities are permitted to charge customers based on allowable costs, including a reasonable ROE. As a result, the traditional electric operating companies and the natural gas distribution utilities apply 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 traditional electric operating companies and the natural gas distribution utilities; therefore, the accounting estimates inherent in specific costs such as depreciation, AROs, and pension and other 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.

Kemper IGCC Estimated Construction Costs, Project Completion Date, and Rate Recovery

During 2016, Mississippi Power further revised its cost estimate to complete construction and start-up of the Kemper IGCC to an amount that exceeds the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions. Mississippi

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Power does not intend to seek any rate recovery for any costs related to the construction of the Kemper IGCC that exceed the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions.
As a result of revisions to the cost estimate, Southern Company recorded total pre-tax charges to income for the estimated probable losses on the Kemper IGCC subject to the construction cost cap of $127 million ($78 million after tax) in the fourth quarter 2016, $88 million ($54 million after tax) in the third quarter 2016, $81 million ($50 million after tax) in the second quarter 2016, $53 million ($33 million after tax) in the first quarter 2016, $183 million ($113 million after tax) in the fourth quarter 2015, $150 million ($93 million after tax) in the third quarter 2015, $23 million ($14 million after tax) in the second quarter 2015, $9 million ($6 million after tax) in the first quarter 2015, $70 million ($43 million after tax) in the fourth quarter 2014, $418 million ($258 million after tax) in the third quarter 2014, $380 million ($235 million after tax) in the first quarter 2014, $40 million ($25 million after tax) in the fourth quarter 2013, $150 million ($93 million after tax) in the third quarter 2013, $450 million ($278 million after tax) in the second quarter 2013, and $540 million ($333 million after tax) in the first quarter 2013. In the aggregate, Southern Company has incurred charges of $2.76 billion ($1.71 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through December 31, 2016.
Mississippi Power's revised cost estimate reflects an expected in-service date of mid-March 2017 and includes certain post-in-service costs which are expected to be subject to the cost cap. Mississippi Power has experienced, and may continue to experience, material changes in the cost estimate for the Kemper IGCC. Further cost increases and/or extensions of the expected in-service date may result from factors including, but not limited to, difficulties integrating the systems required for sustained operations, sustaining nitrogen supply, major equipment failure, unforeseen engineering or design problems including any repairs and/or modifications to systems, and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC).
In addition to the current construction cost estimate, Mississippi Power is also identifying potential improvement projects that ultimately may be completed subsequent to placing the remainder of the Kemper IGCC in service. If completed, such improvement projects would be expected to enhance plant performance, safety, and/or operations. As of December 31, 2016, approximately $12 million of related potential costs has been included in the estimated loss on the Kemper IGCC. Other projects have yet to be fully evaluated, have not been included in the current cost estimate, and may be subject to the $2.88 billion cost cap. In subsequent periods, any further changes in the estimated costs of the Kemper IGCC subject to the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions, will be reflected in Southern Company's statements of income and these changes could be material.
Any extension of the in-service date beyond mid-March 2017 is currently estimated to result in additional base costs of approximately $25 million to $35 million per month, which includes maintaining necessary levels of start-up labor, materials, and fuel, as well as operational resources required to execute start-up and commissioning activities. However, additional costs may be required for remediation of any further equipment and/or design issues identified. Any extension of the in-service date with respect to the Kemper IGCC beyond mid-March 2017 would also increase costs for the Cost Cap Exceptions, which are not subject to the $2.88 billion cost cap established by the Mississippi PSC. These costs include AFUDC, which is currently estimated to total approximately $16 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting and legal fees of approximately $3 million per month.
Mississippi Power continues to believe that all costs related to the Kemper IGCC have been prudently incurred in accordance with the requirements of the 2012 MPSC CPCN Order. Mississippi Power also recognizes significant areas of potential challenge during future regulatory proceedings (and any subsequent, related legal challenges) exist. As described further in Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs," " – Prudence," " – Lignite Mine and CO2 Pipeline Facilities," " – Termination of Proposed Sale of Undivided Interest," " – Bonus Depreciation," " – Investment Tax Credits," and " – Section 174 Research and Experimental Deduction," these challenges include, but are not limited to, prudence issues associated

with capital costs, financing costs (AFUDC), and future operating costs, net of chemical revenues; potential operating parameters; income tax issues; costs deferred as regulatory assets; and the 15% portion of the project previously contracted to SMEPA.

Although the 2017 Rate Case has not yet been filed and is subject to future developments with either the Kemper IGCC or the Mississippi PSC, consistent with its approach in the 2013 and 2015 rate proceedings in accordance with the law passed in 2013 authorizing multi-year rate plans, Mississippi Power is developing both a traditional rate case requesting full cost recovery of the amounts not currently in rates and a rate mitigation plan that together represent Mississippi Power's probable filing strategy. Mississippi Power also expects that timely resolution of the 2017 Rate Case will likely require a negotiated settlement agreement. In the event an agreement acceptable to both Mississippi Power and the MPUS (and other parties) can be negotiated and ultimately approved by the Mississippi PSC, it is reasonably possible that full regulatory recovery of all Kemper IGCC costs will not occur. The impact of such an agreement on Southern Company's financial statements would depend on the method, amount,

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and type of cost recovery ultimately excluded. Certain costs, including operating costs, would be recorded to income in the period incurred, while other costs, including investment-related costs, would be charged to income when it is probable they will not be recovered and the amounts can be reasonably estimated. In the event an agreement acceptable to the parties cannot be reached, Mississippi Power intends to fully litigate its request for full recovery through the Mississippi PSC regulatory process and any subsequent legal challenges.

Mississippi Power has evaluated various scenarios in connection with its processes to prepare the 2017 Rate Case and has recognized an additional $80 million charge to income, which is the estimated minimum probable amount of the $3.31 billion of Kemper IGCC costs not currently in rates that would not be recovered under the probable rate mitigation plan to be filed by June 3, 2017.

Given the significant judgment involved in estimating the future costs to complete construction and start-up, the project completion date, the ultimate rate recovery for the Kemper IGCC, and the potential impact on Southern Company's results of operations, Southern Company considers these items to be critical accounting estimates. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

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 facilities that are subject to the CCR Rule, principally ash ponds, and the decommissioning of the Southern Company system's nuclear facilities – Alabama Power's Plant Farley and Georgia Power's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2. In addition, the Southern Company system has retirement obligations related to various landfill sites, asbestos removal, mine reclamation, land restoration related to solar and wind facilities, and disposal of polychlorinated biphenyls in certain transformers. The Southern Company system also has identified retirement obligations related to certain electric transmission and distribution facilities, certain wireless communication towers, property associated with the Southern Company system's rail lines and natural gas pipelines, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded as 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 cost estimates for AROs related to the disposal of CCR 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. 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 with respect to compliance activities, including the potential for closing ash ponds prior to the end of their currently anticipated useful life, the traditional electric operating companies expect to continue to periodically update these estimates. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Coal Combustion Residuals" herein for additional information.

Given the significant judgment involved in estimating AROs, Southern 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

Southern 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 Southern 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 Southern Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. Southern Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to Southern Company's target asset allocation. For purposes of determining its liability related to the pension and other postretirement benefit plans, Southern Company discounts the future related cash flows using a single-point discount rate for each plan developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments. For 2015 and prior years, Southern 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, Southern Company 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 decreased by approximately $96 million in 2016.

The following table illustrates the sensitivity to changes in Southern Company's long-term assumptions with respect to the assumed discount rate, the assumed salaries, and the assumed long-term rate of return on plan assets:

Change in Assumption	Increase/(Decrease) in Total Benefit Expense for 2017	Increase/(Decrease) in Projected Obligation for Pension Plan at December 31, 2016	Increase/(Decrease) in Projected Obligation for Other Postretirement Benefit Plans at December 31, 2016
	(in millions)		
25 basis point change in discount rate	$34/$(39)	$418/$(396)	$64/$(61)
25 basis point change in salaries	$20/$(19)	$97/$(94)	$–/$–
25 basis point change in long-term return on plan assets	$31/$(31)	N/A	N/A

N/A – Not applicable

See Note 2 to the financial statements for additional information regarding pension and other postretirement benefits.

Goodwill and Other Intangible Assets

The acquisition method of accounting requires the assets acquired and liabilities assumed to be recorded at the date of acquisition at their respective estimated fair values. Southern Company recognizes goodwill as of the acquisition date, as a residual over the fair values of the identifiable net assets acquired. Goodwill is tested for impairment on an annual basis in the fourth quarter of the year as well as on an interim basis as events and changes in circumstances occur. Primarily as a result of the acquisitions of Southern Company Gas and PowerSecure in 2016, goodwill totaled approximately $6.3 billion at December 31, 2016.

Definite-lived intangible assets acquired are amortized over the estimated useful lives of the respective assets to reflect the pattern in which the economic benefits of the intangible assets are consumed. Whenever events or changes in circumstances indicate that the carrying amount of the intangible assets may not be recoverable, the intangible assets will be reviewed for impairment. Primarily as a result of the acquisitions of Southern Company Gas and PowerSecure and PPA fair value adjustments resulting from Southern Power's acquisitions, other intangible assets, net of amortization totaled approximately $1.0 billion at December 31, 2016.

The judgments made in determining the estimated fair value assigned to each class of assets acquired and liabilities assumed, as well as asset lives, can significantly impact Southern Company's results of operations. Fair values and useful lives are determined based on, among other factors, the expected future period of benefit of the asset, the various characteristics of the asset, and projected cash flows. As the determination of an asset's fair value and useful life involves management making certain estimates and because these estimates form the basis for the determination of whether or not an impairment charge should be recorded, Southern Company considers these estimates to be critical accounting estimates.

See Note 1 to the financial statements under "Goodwill and Other Intangible Assets and Liabilities" for additional information regarding Southern Company's goodwill and other intangible assets and Note 12 to the financial statements for additional information related to Southern Company's recent acquisitions.

Derivatives and Hedging Activities

Derivative instruments are recorded on the balance sheets as either assets or liabilities measured at their fair value, unless the transactions qualify for the normal purchases or normal sales scope exception and are instead subject to traditional accrual accounting. For those transactions that do not qualify as a normal purchase or normal sale, changes in the derivatives' fair values are recognized concurrently in earnings unless specific hedge accounting criteria are met. If the derivatives meet those criteria, derivative gains and losses offset related results of the hedged item in the income statement in the case of a fair value hedge, or gains and losses are deferred in OCI until the hedged transaction affects earnings in the case of a cash flow hedge. Certain subsidiaries of Southern Company enter into energy-related derivatives that are designated as regulatory hedges where gains and losses are initially recorded as regulatory liabilities and assets and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through billings to customers.

Southern Company uses derivative instruments to reduce the impact to the results of operations due to the risk of changes in the price of natural gas, to manage fuel hedging programs per guidelines of state regulatory agencies, and to mitigate residual changes in the price of electricity, weather, interest rates, and foreign currency exchange rates. The fair value of commodity derivative instruments used to manage exposure to changing prices reflects the estimated amounts that Southern Company would receive or pay to terminate or close the contracts at the reporting date. To determine the fair value of the derivative instruments, Southern Company utilizes market data or assumptions that market participants would use in pricing the derivative asset or liability, including assumptions about risk and the risks inherent in the inputs of the valuation technique.

Southern Company classifies derivative assets and liabilities based on the lowest level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy. The determination of the fair value of the derivative instruments incorporates various required factors. These factors include:

- the creditworthiness of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit);
- events specific to a given counterparty; and
- the impact of Southern Company's nonperformance risk on its liabilities.

Given the assumptions used in pricing the derivative asset or liability, Southern Company considers the valuation of derivative assets and liabilities a critical accounting estimate. See FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" herein for more information.

Contingent Obligations

Southern 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, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. Southern 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 and records a tax asset or liability if it is more likely than not that a tax position will be sustained. 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 Southern Company's results of operations, cash flows, or financial condition.

Recently Issued Accounting Standards

In 2014, the FASB issued ASC 606, Revenue from Contracts with Customers, replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the guidance is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

While Southern Company expects most of its revenue to be included in the scope of ASC 606, it has not fully completed its evaluation of such arrangements. The majority of Southern Company's revenue, including energy provided to customers, is from tariff offerings that provide natural gas or electricity without a defined contractual term. For such arrangements, Southern Company generally expects that the revenue from contracts with these customers will continue to be equivalent to the electricity or natural gas supplied and billed in that period (including unbilled revenues) and the adoption of ASC 606 will not result in a significant shift in the timing of revenue recognition for such sales.

Southern Company's ongoing evaluation of other revenue streams and related contracts includes longer term contractual commitments and unregulated sales to customers. Some revenue arrangements, such as certain PPAs and alternative revenue programs, are expected to be excluded from the scope of ASC 606 and therefore, be accounted for and presented separately from revenues under ASC 606 on Southern Company's financial statements. In addition, the power and utilities industry is currently addressing other specific industry issues, including the applicability of ASC 606 to CIAC. If final implementation guidance indicates CIAC will be accounted for under ASC 606 and offsetting regulatory treatment is not permitted, it could have a material impact on Southern Company's financial statements.

The new standard is effective for interim and annual reporting periods beginning after December 15, 2017. Southern Company must select a transition method to be applied either retrospectively to each prior reporting period presented or retrospectively with a cumulative effect adjustment to retained earnings at the date of initial adoption. As the ultimate impact of the new standard has not yet been determined, Southern Company has not elected its transition method.

On February 25, 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842) (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged and there is no change to the accounting for existing leveraged leases. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. Southern Company is currently evaluating the new standard and has not yet determined its ultimate impact; however, adoption of ASU 2016-02 is expected to have a significant impact on Southern Company's balance sheet.

On March 30, 2016, the FASB issued ASU No. 2016-09, Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting (ASU 2016-09). ASU 2016-09 changes the accounting for income taxes and the cash flow presentation for share-based payment award transactions effective for fiscal years beginning after December 15, 2016. The new guidance requires all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation to be recognized as income tax expense or benefit in the income statement. Previously, Southern Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities rather than net cash provided from financing activities on the statement of cash flows. Southern Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. Southern Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of Southern Company. See Notes 5, 8, and 14 to the financial statements for disclosures impacted by ASU 2016-09.

On October 24, 2016, the FASB issued ASU No. 2016-16, Income Taxes (Topic 740), Intra-Entity Transfers of Assets Other Than Inventory (ASU 2016-16). Current GAAP prohibits the recognition of current and deferred income taxes for an affiliate asset transfer until the asset has been sold to an outside party. ASU 2016-16 requires an entity to recognize the income tax consequences of an affiliate transfer of an asset other than inventory when the transfer occurs. ASU 2016-16 is effective for annual reporting periods beginning after December 15, 2017 and interim periods within those annual periods. The amendments will be applied on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. Southern Company is currently assessing the impact of the standard on its financial statements and has not yet determined its ultimate impact.

On November 17, 2016, the FASB issued ASU No. 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash (ASU 2016-18). ASU 2016-18 eliminates the need to reflect transfers between cash and restricted cash in operating, investing, and financing activities in the statement of cash flows. Upon adoption, the net change in cash and cash equivalents during the period will include amounts generally described as restricted cash or restricted cash equivalents. ASU 2016-18 is effective for fiscal years beginning after December 15, 2017, with early adoption permitted, and will be applied retrospectively to each period presented. Southern Company does not intend to adopt the guidance early. The adoption of ASU 2016-18 will not have a material impact on the financial statements of

Southern Company.

FINANCIAL CONDITION AND LIQUIDITY

Overview

Earnings in all periods presented were negatively affected by revisions to the cost estimate for the Kemper IGCC; however, Southern Company's financial condition remained stable at December 31, 2016.

The Southern Company system's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. The Southern Company system's capital expenditures and other investing activities include investments to meet projected long-term demand requirements, including to build new electric generation facilities, to maintain existing electric generation facilities, to comply with environmental regulations including adding environmental modifications to certain existing electric generating units, to expand and improve electric transmission and distribution facilities,

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to update and expand natural gas distribution systems, and for restoration following major storms. Operating cash flows provide a substantial portion of the Southern Company system's cash needs. For the three-year period from 2017 through 2019, Southern Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Southern Company plans to finance future cash needs in excess of its operating cash flows primarily by accessing borrowings from financial institutions and through debt and equity issuances in the capital markets. Southern Company intends to continue to monitor its access to short-term and long-term capital markets as well as bank credit arrangements to meet future capital and liquidity needs. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Bonus Depreciation" and "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

Southern Company's investments in the qualified pension plans and the nuclear decommissioning trust funds increased in value as of December 31, 2016 as compared to December 31, 2015. On December 19, 2016, the traditional electric operating companies and certain other subsidiaries voluntarily contributed an aggregate of $900 million to Southern Company's qualified pension plan. In addition, on September 12, 2016, Southern Company Gas voluntary contributed $125 million to its qualified pension plan. No mandatory contributions to the qualified pension plans are anticipated during 2017. See "Contractual Obligations" herein and Notes 1 and 2 to the financial statements under "Nuclear Decommissioning" and "Pension Plans," respectively, for additional information.

Net cash provided from operating activities in 2016 totaled $4.9 billion, a decrease of $1.4 billion from 2015. The decrease in net cash provided from operating activities was primarily due to voluntary contributions to the qualified pension plan of approximately $1.0 billion and a $1.2 billion increase in unutilized ITCs and PTCs. Net cash provided from operating activities in 2015 totaled $6.3 billion, an increase of $459 million from 2014. Significant changes in operating cash flow for 2015 as compared to 2014 included an increase in fuel cost recovery, partially offset by the timing of vendor payments.

Net cash used for investing activities in 2016, 2015, and 2014 totaled $20.0 billion, $7.3 billion, and $6.4 billion, respectively. The cash used for investing activities in 2016 was primarily due to the closing of the Merger, the acquisition of PowerSecure, Southern Company Gas' investment in SNG, the construction of electric generation, transmission, and distribution facilities, the installation of equipment at electric generating facilities to comply with environmental standards, and Southern Power's acquisitions and construction of renewable facilities and a natural gas facility. The cash used for investing activities in 2015 and 2014 was primarily due to gross property additions for installation of equipment at electric generating facilities to comply with environmental standards, construction of electric generation, transmission, and distribution facilities, Southern Power's acquisitions of solar facilities, and purchases of nuclear fuel.

Net cash provided from financing activities totaled $15.7 billion in 2016 primarily due to issuances of long-term debt and common stock associated with completing the Merger and funding the subsidiaries' continuous construction programs, Southern Power's acquisitions, and Southern Company Gas' investment in SNG, partially offset by redemptions of long-term debt and common stock dividend payments. Net cash provided from financing activities totaled $1.7 billion in 2015 due to issuances of long-term debt and common stock and an increase in short-term debt, partially offset by common stock dividend payments and redemptions of long-term debt and preferred and preference stock. Net cash provided from financing activities totaled $644 million in 2014 due to issuances of long-term debt and common stock, partially offset by common stock dividend payments, redemptions of long-term debt, and a reduction in short-term debt. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes in 2016 included an increase of $17.3 billion in total property, plant, and equipment primarily related to the inclusion of Southern Company Gas as a result of the Merger, installation of equipment at electric generating facilities to comply with environmental standards, construction of electric generation, transmission, and distribution facilities, and Southern Power's acquisitions; an increase of $6.2 billion in goodwill related to the acquisitions of Southern Company Gas and PowerSecure; an increase of $1.5 billion in equity investments in unconsolidated subsidiaries primarily related to Southern Company Gas' investment in SNG; an increase of $1.9 billion in other regulatory assets, deferred primarily related to the inclusion of Southern Company Gas as a result of the Merger and changes in ash pond closure strategy, principally for Georgia Power; increases of $17.9 billion in long-term debt and $4.6 billion in total stockholder's equity primarily associated with financing and completing the Merger and to fund the subsidiaries' continuous construction programs and Southern Power's acquisitions; and increases of $1.8 billion in accumulated deferred income taxes and $1.6 billion in other cost of removal obligations primarily related to the inclusion of Southern Company Gas as a result of the Merger. See Notes 1 and 12 to the financial statements for additional information regarding AROs and the Merger, respectively.

At the end of 2016, the market price of Southern Company's common stock was $49.19 per share (based on the closing price as reported on the New York Stock Exchange) and the book value was $25.00 per share, representing a market-to-book value ratio of 197%, compared to $46.79, $22.59, and 207%, respectively, at the end of 2015.

Southern Company's consolidated ratio of common equity to total capitalization plus short-term debt was 33.3% and 40.5% at December 31, 2016 and 2015, respectively. See Note 6 to the financial statements for additional information.

Sources of Capital

Southern Company intends to meet its future capital needs through operating cash flows, short-term debt, term loans, and external security issuances. Equity capital can be provided from any combination of the Company's stock plans, private placements, or public offerings. The amount and timing of additional equity capital and debt issuances in 2017, as well as in subsequent years, will be contingent on Southern Company's investment opportunities and the Southern Company system's capital requirements and will depend upon prevailing market conditions and other factors. See "Capital Requirements and Contractual Obligations" herein for additional information.

Except as described herein, the traditional electric operating companies, Southern Power, and Southern Company Gas plan to obtain the funds required for construction and other purposes from operating cash flows, external security issuances, term loans, short-term borrowings, and equity contributions or loans from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors.

In addition, Georgia Power may make borrowings through a loan guarantee agreement (Loan Guarantee Agreement) between Georgia Power and the DOE, the proceeds of which may be used to reimburse Georgia Power for a portion of certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the Loan Guarantee Agreement (Eligible Project Costs). Under the Loan Guarantee Agreement, the DOE agreed to guarantee borrowings of up to $3.46 billion (not to exceed 70% of Eligible Project Costs) to be made by Georgia Power under a multi-advance credit facility (FFB Credit Facility) among Georgia Power, the DOE, and the FFB. Eligible Project Costs incurred through December 31, 2016 would allow for borrowings of up to $2.7 billion under the FFB Credit Facility, of which Georgia Power has borrowed $2.6 billion. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information regarding the Loan Guarantee Agreement and Note 3 to the financial statements under "Regulatory Matters – Georgia Power – Nuclear Construction" for additional information regarding Plant Vogtle Units 3 and 4.

Mississippi Power received $245 million of Initial DOE Grants in prior years that were used for the construction of the Kemper IGCC. An additional $25 million of grants from the DOE is expected to be received for commercial operation of the Kemper IGCC. On April 8, 2016, Mississippi Power received approximately $137 million in Additional DOE Grants for the Kemper IGCC, which are expected to be used to reduce future rate impacts for customers. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for information regarding legislation related to the securitization of certain costs of the Kemper IGCC.

The issuance of securities by the traditional electric operating companies and Nicor Gas is generally subject to the approval of the applicable state PSC or other applicable state regulatory agency. The issuance of all securities by Mississippi Power and short-term securities by Georgia Power is generally subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, Southern Company and certain of its subsidiaries file registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the appropriate regulatory authorities, as well as the securities registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

Southern Company, each traditional electric operating company, and Southern Power generally obtain financing separately without credit support from any affiliate. In addition, Southern Company Gas Capital obtains external financing for Southern Company Gas and its subsidiaries, other than Nicor Gas, which obtains financing separately without credit support from any affiliates. 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 each company are not commingled with funds of any other company in the Southern Company system.

As of December 31, 2016, Southern Company's current liabilities exceeded current assets by $3.2 billion, primarily due to $2.6 billion of long-term debt that is due within one year, including approximately $0.8 billion at the parent company, $0.6 billion at Alabama Power, $0.5 billion at Georgia Power, $0.1 billion at Gulf Power, and $0.6 billion at Southern Power. To meet short-term cash needs and contingencies, the Southern Company system has substantial cash flow from operating activities and access to capital markets and financial institutions. Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas intend to utilize operating cash flows, as well as commercial paper, lines of credit, bank notes, and securities issuances, as market conditions permit, as well as, under certain circumstances for the traditional electric operating companies, Southern Power, and Southern Company Gas, equity contributions and/or loans from Southern Company to meet their short-term capital needs. In addition, Georgia Power expects to utilize borrowings through the FFB Credit Facility as an additional source of long-term borrowed funds.

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At December 31, 2016, Southern Company and its subsidiaries had approximately $2.0 billion of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2016 were as follows:

	Expires					Executable Term Loans		Expires Within One Year	
Company	2017	2018	2020	Total	Unused	One Year	Two Years	Term Out	No Term Out
	(in millions)			(in millions)		(in millions)		(in millions)	
Southern Company[(a)]	$—	$1,000	$1,250	$2,250	$2,250	$—	$ —	$—	$—
Alabama Power	35	500	800	1,335	1,335	—	—	—	35
Georgia Power	—	—	1,750	1,750	1,732	—	—	—	—
Gulf Power	85	195	—	280	280	45	—	25	60
Mississippi Power	173	—	—	173	150	—	13	13	160
Southern Power Company[(b)]	—	—	600	600	522	—	—	—	—
Southern Company Gas[(c)]	75	1,925	—	2,000	1,949	—	—	—	75
Other	55	—	—	55	55	20	—	20	35
Southern Company Consolidated	$423	$3,620	$4,400	$8,443	$8,273	$ 65	$ 13	$58	$ 365

(a) Represents the Southern Company parent entity.

(b) Excludes credit agreements (Project Credit Facilities) assumed with the acquisition of certain solar facilities, which were non-recourse to Southern Power Company, the proceeds of which were used to finance project costs related to such solar facilities. See Note 12 to the financial statements under "Southern Power" for additional information. Also excludes a $120 million continuing letter of credit facility entered into by Southern Power in December 2016 for standby letters of credit expiring in 2019. At December 31, 2016, the total amount available under the letter of credit facility was $82 million.

(c) Southern Company Gas, as the parent entity, guarantees the obligations of Southern Company Gas Capital, which is the borrower of $1.3 billion of these arrangements. Southern Company Gas' committed credit arrangements also include $700 million for which Nicor Gas is the borrower and which is restricted for working capital needs of Nicor Gas.

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

Most of these bank credit arrangements, as well as the term loan arrangements of Southern Company, Alabama Power, Gulf Power, Mississippi Power, and Southern Power Company, contain covenants that limit debt levels and contain cross acceleration or cross default provisions to other indebtedness (including guarantee obligations) that are restricted only to the indebtedness of the individual company. Such cross default provisions to other indebtedness would trigger an event of default if the applicable borrower defaulted on indebtedness or guarantee obligations over a specified threshold. Such cross acceleration provisions to other indebtedness would trigger an event of default if the applicable borrower defaulted on indebtedness, the payment of which was then accelerated. At December 31, 2016, Southern Company, the traditional electric operating companies, Southern Power Company, Southern Company Gas, and Nicor Gas were 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, Southern Company and its subsidiaries expect to renew or replace their bank credit arrangements as needed, prior to expiration. In connection therewith, Southern Company and its subsidiaries 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 pollution control revenue bonds of the traditional electric operating companies and the commercial paper programs of Southern Company, the traditional electric operating companies, Southern Power Company, Southern Company Gas, and Nicor Gas. The amount of variable rate pollution control revenue bonds of the traditional electric operating companies outstanding requiring liquidity support as of December 31, 2016 was approximately $1.9 billion. In addition, at December 31, 2016, the traditional electric operating companies had approximately $423 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

Southern Company, the traditional electric operating companies, Southern Power Company, Southern Company Gas, and Nicor Gas make short-term borrowings primarily through commercial paper programs that have the liquidity support of the committed bank credit arrangements described above. Short-term borrowings are included in notes payable in the balance sheets.

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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, 2016:					
Commercial paper	$1,909	1.1 %	$ 976	0.8 %	$ 1,970
Short-term bank debt	123	1.7 %	176	1.7 %	500
Total	$2,032	1.1 %	$ 1,152	1.1 %	
December 31, 2015:					
Commercial paper	$740	0.7 %	$ 842	0.4 %	$ 1,563
Short-term bank debt	500	1.4 %	444	1.1 %	795
Total	$1,240	0.9 %	$ 1,286	0.5 %	
December 31, 2014:					
Commercial paper	$803	0.3 %	$ 754	0.2 %	$ 1,582
Short-term bank debt	—	— %	98	0.8 %	400
Total	$803	0.3 %	$ 852	0.3 %	

(*) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2016, 2015, and 2014.

In addition to the short-term borrowings in the table above, Southern Power's subsidiary Project Credit Facilities had total amounts outstanding as of December 31, 2016 of $209 million at a weighted average interest rate of 2.1%. For the year ended December 31, 2016, the Project Credit Facilities had a maximum amount outstanding of $828 million and an average amount outstanding of $566 million at a weighted average interest rate of 2.1%. The amounts outstanding as of December 31, 2016 under the Project Credit Facilities were fully repaid subsequent to December 31, 2016.

Furthermore, in connection with the acquisition of a solar facility on July 1, 2016, a subsidiary of Southern Power assumed a $217 million construction loan, which was fully repaid in September 2016. During this period, the credit agreement had a maximum amount outstanding of $217 million and an average amount outstanding of $137 million at a weighted average interest rate of 2.2%.

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

Financing Activities

In May and August 2016, Southern Company issued an aggregate of 50.8 million shares of common stock in underwritten offerings for an aggregate purchase price of approximately $2.5 billion. Of the 50.8 million shares, approximately 2.6 million were issued from treasury and the remainder were newly issued shares. The proceeds were used to fund a portion of the consideration for the Merger and related transaction costs, to fund a portion of the purchase price for the SNG investment and related transaction costs, and for other general corporate purposes.

During the fourth quarter 2016, Southern Company issued approximately 8.0 million shares of common stock through at-the-market issuances pursuant to sales agency agreements related to Southern Company's continuous equity

offering program and received cash proceeds of approximately $381 million, net of $3 million in fees and commissions.
In addition, during 2016, Southern Company issued approximately 20 million shares of common stock primarily through employee equity compensation plans and received proceeds of approximately $874 million.

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The following table outlines the long-term debt financing activities for Southern Company and its subsidiaries for the year ended December 31, 2016:

Company	Senior Note Issuances	Senior Note Maturities and Redemptions	Revenue Bond Maturities, Redemptions, and Repurchases	Other Long-Term Debt Issuances	Other Long-Term Debt Redemptions and Maturities[(a)]
	(in millions)				
Southern Company[(b)]	$8,500	$ 500	$ —	$ 1,350	$ —
Alabama Power	400	200	—	45	—
Georgia Power	650	700	4	425	10
Gulf Power	—	235	—	2	—
Mississippi Power	—	300	—	1,400	653
Southern Power	2,831	200	—	65	86
Southern Company Gas[(c)]	900	420	—	—	—
Other	—	—	—	79	65
Elimination[(d)]	—	—	—	(279)	(228)
Southern Company Consolidated	$13,281	$ 2,555	$ 4	$ 3,087	$ 586

(a) Includes reductions in capital lease obligations resulting from cash payments under capital leases.
(b) Represents the Southern Company parent entity.
(c) Reflects only long-term debt financing activities occurring subsequent to completion of the Merger. The senior notes were issued by Southern Company Gas Capital and guaranteed by Southern Company Gas, as the parent entity.
(d) Includes intercompany loans from Southern Company to Mississippi Power and PowerSecure, as well as reductions in affiliate capital lease obligations at Georgia Power. These transactions are eliminated in Southern Company's Consolidated Financial Statements.

In February 2016, Southern Company entered into $700 million notional amount of forward-starting interest rate swaps to hedge exposure to interest rate changes related to anticipated debt issuances. These interest rate swaps were settled in May 2016.

In May 2016, Southern Company issued the following series of senior notes for an aggregate principal amount of $8.5 billion:

- $0.5 billion of 1.55% Senior Notes due July 1, 2018;
- $1.0 billion of 1.85% Senior Notes due July 1, 2019;
- $1.5 billion of 2.35% Senior Notes due July 1, 2021;
- $1.25 billion of 2.95% Senior Notes due July 1, 2023;
- $1.75 billion of 3.25% Senior Notes due July 1, 2026;
- $0.5 billion of 4.25% Senior Notes due July 1, 2036; and
- $2.0 billion of 4.40% Senior Notes due July 1, 2046.

The net proceeds were used to fund a portion of the consideration for the Merger and related transaction costs and for other general corporate purposes.

In September 2016, Southern Company issued $800 million aggregate principal amount of Series 2016A 5.25% Junior Subordinated Notes due October 1, 2076. The proceeds were used to repay short-term indebtedness that was incurred to repay at maturity $500 million aggregate principal amount of Southern Company's Series 2011A 1.95% Senior Notes due September 1, 2016 and for other general corporate purposes.

In December 2016, Southern Company issued $550 million aggregate principal amount of Series 2016B Junior Subordinated Notes due March 15, 2057, which bear interest at a fixed rate of 5.50% per year up to, but not including, March 15, 2022. From, and including, March 15, 2022, the Series 2016B Junior Subordinated Notes will bear interest at a floating rate based on three-month LIBOR. The proceeds were used for general corporate purposes.

Except as described herein, Southern Company's subsidiaries used the proceeds of the debt issuances shown in the table above for their redemptions and maturities shown in the table above, to repay short-term indebtedness, and for general corporate purposes, including their continuous construction programs and, for Southern Power, its growth strategy. In addition, certain of Georgia Power's and Southern Power's issuances were allocated to eligible renewable energy expenditures.

Georgia Power's "Other Long-Term Debt Issuances" reflected in the table above include borrowings in June and December 2016 under the FFB Credit Facility in an aggregate principal amount of $300 million and $125 million, respectively. The interest rate applicable to the $300 million principal amount is 2.571% and the interest rate applicable to the $125 million principal amount is 3.142%, both for interest periods that extend to the final maturity date of February 20, 2044. The proceeds were used to reimburse Georgia Power for Eligible Project Costs relating to the construction of Plant Vogtle Units 3 and 4.

In June 2016, Southern Power Company issued €600 million aggregate principal amount of Series 2016A 1.00% Senior Notes due June 20, 2022 and €500 million aggregate principal amount of Series 2016B 1.85% Senior Notes due June 20, 2026. The net proceeds are being allocated to renewable energy generation projects. Southern Power Company's obligations under its euro-denominated fixed-rate notes were effectively converted to fixed-rate U.S. dollars at issuance through cross-currency swaps, mitigating foreign currency exchange risk associated with the interest and principal payments. See Note 11 to the financial statements under "Foreign Currency Derivatives" for additional information.

In September 2016, Southern Company Gas Capital issued $350 million aggregate principal amount of 2.45% Senior Notes due October 1, 2023 and $550 million aggregate principal amount of 3.95% Senior Notes due October 1, 2046, both of which are guaranteed by Southern Company Gas. The proceeds were primarily used to repay a $360 million promissory note issued to Southern Company for the purpose of funding a portion of the purchase price for a 50% equity interest in SNG, to fund the purchase of Piedmont Natural Gas Company, Inc.'s interest in SouthStar Energy Services, LLC, to make a voluntary contribution to Southern Company Gas' pension plan, and for general corporate purposes. See Note 12 to the financial statements under "Southern Company – Investment in Southern Natural Gas" and " – Acquisition of Remaining Interest in SouthStar" for additional information.

Subsequent to December 31, 2016, Alabama Power repaid at maturity $200 million aggregate principal amount of its Series 2007A 5.55% Senior Notes due February 1, 2017.

In March 2016, Alabama Power entered into three bank term loan agreements with maturity dates of March 2021, in an aggregate principal amount of $45 million, one of which bears interest at 2.38% per annum and two of which bear interest based on three-month LIBOR.

In March 2016, Mississippi Power entered into an unsecured term loan agreement with a syndicate of financial institutions for an aggregate amount of $1.2 billion. Mississippi Power borrowed $900 million in March 2016 under the term loan agreement and the remaining $300 million in October 2016. Mississippi Power used the initial proceeds to repay $900 million in maturing bank loans in March 2016 and the remaining $300 million to repay at maturity Mississippi Power's Series 2011A 2.35% Senior Notes due October 15, 2016. This loan matures on April 1, 2018 and bears interest based on one-month LIBOR.

In May 2016, Gulf Power entered into an 11-month floating rate bank loan bearing interest based on one-month LIBOR. This short-term loan was for $100 million aggregate principal amount and the proceeds were used to repay existing indebtedness and for working capital and other general corporate purposes.

In September 2016, Southern Power Company repaid $80 million of an outstanding $400 million floating rate bank loan and extended the maturity date of the remaining $320 million from September 2016 to September 2018. In addition, Southern Power Company entered into a $60 million aggregate principal amount floating rate bank loan bearing interest based on one-month LIBOR due September 2017. The proceeds were used to repay existing indebtedness and for other general corporate purposes.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, Southern Company and its subsidiaries plan 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

At December 31, 2016, Southern Company and its subsidiaries did 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 of certain subsidiaries to BBB and/or Baa2 or below. These contracts are for physical electricity and natural gas purchases and sales, fuel purchases, fuel transportation and storage, energy price risk management, transmission, interest rate management, foreign currency risk management, and construction of new generation at Plant Vogtle Units 3 and 4.

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The maximum potential collateral requirements under these contracts at December 31, 2016 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements (in millions)
At BBB and/or Baa2	$ 39
At BBB- and/or Baa3	$ 691
At BB+ and/or Ba1(*)	$ 2,723

(*) Any additional credit rating downgrades at or below BB- and/or Ba3 could increase collateral requirements up to an additional $91 million.

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 Southern Company and its subsidiaries to access capital markets and would be likely to impact the cost at which they do so.

On May 12, 2016, Fitch Ratings, Inc. (Fitch) downgraded the senior unsecured long-term debt rating of Southern Company to A- from A and revised the ratings outlook from negative to stable. Fitch also downgraded the senior unsecured long-term debt rating of Mississippi Power to BBB+ from A- and revised the ratings outlook from negative to stable.

On May 13, 2016, Moody's downgraded the senior unsecured long-term debt rating of Southern Company to Baa2 from Baa1 and revised the ratings outlook from negative to stable.

On July 11, 2016, S&P raised Southern Company Gas' and Nicor Gas' corporate and senior unsecured long-term debt ratings from BBB+ to A- and revised their ratings outlooks from positive to negative.

On January 10, 2017, S&P revised its consolidated credit rating outlook for Southern Company (including the traditional electric operating companies, Southern Power, and Southern Company Gas) from negative to stable.

On February 6, 2017, Moody's placed Mississippi Power on a ratings review for potential downgrade. Mississippi Power's current rating for unsecured debt is Baa3.

Market Price Risk

The Southern Company system is exposed to market risks, including commodity price risk, interest rate risk, weather risk, and occasionally foreign currency exchange rate risk. To manage the volatility attributable to these exposures, the applicable 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 applicable company's policies in areas such as counterparty exposure and risk management practices. The Southern Company system's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to a change in interest rates, Southern Company and certain of its subsidiaries enter into derivatives that have been designated as hedges. Derivatives that have been designated as hedges outstanding at December 31, 2016 have a notional amount of $4.0 billion, of which $0.1 billion are to mitigate interest rate volatility related to projected debt financings in 2017. The remaining $3.9 billion are related to existing fixed and floating rate obligations. The weighted average interest rate on $6.4 billion of long-term variable interest rate exposure at January 1, 2017 was 1.68%. If Southern Company sustained a 100 basis point change in interest rates for all long-term variable interest rate exposure, the change would affect annualized interest expense by approximately $63 million at January 1, 2017. See Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements for additional information.

Due to cost-based rate regulation and other various cost recovery mechanisms, the traditional electric operating companies and natural gas distribution utilities continue to have limited exposure to market volatility in interest rates, foreign currency exchange rates, commodity fuel prices, and prices of electricity. In addition, Southern Power's exposure to market volatility in commodity fuel prices and prices of electricity is limited because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, Southern Power has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of uncontracted generating capacity. To mitigate residual risks relative to movements in electricity prices, the traditional electric operating companies and Southern Power may enter into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, financial hedge contracts for natural gas purchases; however, a significant portion of contracts are priced at market. The traditional electric operating companies and certain of the natural gas distribution utilities manage fuel-hedging programs implemented per the guidelines of

their respective state PSCs or other applicable state regulatory agencies. Southern Company had no material change in market risk exposure for the year ended December 31, 2016 when compared to the year ended December 31, 2015.
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:

	2016 Changes	2015 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	$(213)	$(188)
Acquisitions	(54)	—
Contracts realized or settled	141	142
Current period changes(*)	171	(167)
Contracts outstanding at the end of the period, assets (liabilities), net	$45	$(213)

(*) 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 were 500 million mmBtu and 224 million mmBtu for the years ended December 31, 2016 and 2015, respectively.
For the traditional electric operating companies and Southern Power, the weighted average swap contract cost above or (below) market prices was approximately $(0.05) per mmBtu as of December 31, 2016 and $1.14 per mmBtu as of December 31, 2015. The majority of the natural gas hedge gains and losses are recovered through the traditional electric operating companies' fuel cost recovery clauses.
At December 31, 2016 and 2015, substantially all of the Southern Company system's energy-related derivative contracts were designated as regulatory hedges and were related to the applicable 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 Southern Company system uses exchange-traded market-observable contracts, which are categorized as Level 1 of the fair value hierarchy, and 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 of the fair value hierarchy. See Note 10 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts at December 31, 2016 were as follows:

	Fair Value Measurements			
	December 31, 2016			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
	(in millions)			
Level 1	$(7)	$15	$(15)	$(7)
Level 2	52	52	(7)	7
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$45	$67	$(22)	$—

The Southern Company system is exposed to market price risk in the event of nonperformance by counterparties to energy-related and interest rate derivative contracts. The Southern Company system 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 Southern Company system 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.

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Southern Company performs periodic reviews of its leveraged lease transactions, both domestic and international, and the creditworthiness of the lessees, including a review of the value of the underlying leased assets and the credit ratings of the lessees. Southern Company's domestic lease transactions generally do not have any credit enhancement mechanisms; however, the lessees in its international lease transactions have pledged various deposits as additional security to secure the obligations. The lessees in the Company's international lease transactions are also required to provide additional collateral in the event of a credit downgrade below a certain level.

Capital Requirements and Contractual Obligations

The Southern Company system's construction program is currently estimated to total approximately $9.1 billion for 2017, $8.2 billion for 2018, $7.3 billion for 2019, $6.9 billion for 2020, and $6.4 billion for 2021. These amounts include expenditures of approximately $0.7 billion, $0.5 billion, $0.3 billion, and $0.1 billion for the construction of Plant Vogtle Units 3 and 4 in 2017, 2018, 2019, and 2020, respectively, $0.3 billion for the construction of the Kemper IGCC in 2017, and $1.5 billion per year for 2017 through 2021 for acquisitions and/or construction of new Southern Power generating facilities. These amounts also include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. Estimated capital expenditures to comply with environmental statutes and regulations included in these amounts are $0.9 billion, $0.7 billion, $0.3 billion, $0.4 billion, and $0.6 billion for 2017, 2018, 2019, 2020, and 2021, respectively. These estimated expenditures do not include potential compliance costs that may arise from the EPA's final rules and guidelines or future state plans that would limit CO_2 emissions from existing, new, 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 traditional electric operating companies also anticipate costs associated with closure and monitoring of ash ponds in accordance with the CCR Rule, which are reflected in the Company's ARO liabilities. These costs, which could change as the Southern Company system continues to refine its assumptions underlying the cost estimates and evaluate the method and timing of compliance activities, are estimated to be approximately $0.4 billion, $0.3 billion, $0.3 billion, $0.4 billion, and $0.4 billion for 2017, 2018, 2019, 2020, and 2021, respectively. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

The construction programs are 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 electric generating plants, including unit retirements and replacements and adding or changing fuel sources at existing electric generating units, to meet regulatory requirements; changes in FERC rules and regulations; state regulatory agency approvals; changes in the expected environmental compliance program; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. Additionally, planned expenditures for plant acquisitions may vary due to market opportunities and Southern Power's ability to execute its growth strategy. See Note 12 to the financial statements under "Southern Power" for additional information regarding Southern Power's plant acquisitions.

In addition, the construction program includes the development and construction of new electric generating facilities with designs that have not been finalized or previously constructed, including first-of-a-kind technology, which may result in revised estimates during construction. See Note 3 to the financial statements under "Regulatory Matters – Georgia Power – Nuclear Construction" and "Integrated Coal Gasification Combined Cycle" for information regarding additional factors that may impact construction expenditures.

As a result of NRC requirements, Alabama Power and Georgia Power have external trust funds for nuclear decommissioning costs; however, Alabama Power 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, Southern Company provides postretirement benefits to the majority of its employees and funds trusts to the extent required by PSCs, other applicable state regulatory agencies, or the FERC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, unrecognized tax benefits, pipeline charges, storage capacity, gas supply, asset management agreements, standby letters of credit and performance/surety bonds, other purchase commitments, and trusts are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 11 to the financial statements for additional information.

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Contractual Obligations

The Southern Company system's contractual obligations at December 31, 2016 were as follows:

	2017	2018-2019	2020-2021	After 2021	Total
	(in millions)				
Long-term debt[a] —					
Principal	$2,556	$7,025	$4,448	$30,890	$44,919
Interest	1,635	3,034	2,592	24,055	31,316
Preferred and preference stock dividends[b]	45	91	91	—	227
Financial derivative obligations[c]	516	101	12	1	630
Operating leases[d]	152	247	190	1,195	1,784
Capital leases[d]	16	32	22	79	149
Unrecognized tax benefits[e]	484	—	—	—	484
Pipeline charges, storage capacity, and gas supply[f]	822	1,049	746	2,591	5,208
Asset management agreements[g]	10	7	—	—	17
Standby letters of credit, performance/surety bonds[h]	85	1	—	—	86
Purchase commitments —					
Capital[i]	8,797	14,649	12,055	—	35,501
Fuel[j]	3,763	4,379	2,248	7,095	17,485
Purchased power[k]	362	753	782	2,651	4,548
Other[l]	479	560	777	3,024	4,840
Trusts —					
Nuclear decommissioning[m]	5	11	11	99	126
Pension and other postretirement benefit plans[n]	146	293	—	—	439
Total	$19,873	$32,232	$23,974	$71,680	$147,759

(a) All amounts are reflected based on final maturity dates except for amounts related to FFB borrowings. As it relates to the FFB borrowings, the final maturity date is February 20, 2044; however, principal amortization is reflected beginning in 2020. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information. Southern Company and its subsidiaries plan 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, 2017, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt principal for 2017 includes $40 million of pollution control revenue bonds that are classified on the balance sheet at December 31, 2016 as short-term since they are variable rate demand obligations that are supported by short-term credit facilities; however, the final maturity date is in 2028. Long-term debt excludes capital lease amounts (shown separately).

(b) Represents preferred and preference stock of subsidiaries. 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 included in "Purchased power."

(e) See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

(f) Includes charges recoverable through a natural gas cost recovery mechanism, or alternatively billed to marketers selling retail natural gas, and demand charges associated with Southern Company Gas' wholesale gas services. The gas supply balance includes amounts for gas commodity purchase commitments associated with Southern

Company Gas' gas marketing services of 33 million mmBtu at floating gas prices calculated using forward natural gas prices at December 31, 2016 and valued at $106 million. Southern Company Gas provides guarantees to certain gas suppliers for certain of its subsidiaries in support of payment obligations.

(g) Represents fixed-fee minimum payments for asset management agreements associated with wholesale gas services.

(h) Guarantees are provided to certain municipalities and other agencies and certain natural gas suppliers in support of payment obligations.

(i) The Southern Company system provides estimated capital expenditures for a five-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, 2016, 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.

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(j) Primarily 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, 2016.

(k) Estimated minimum long-term obligations for various PPA purchases from gas-fired, biomass, and wind-powered facilities. Includes a total of $292 million of biomass PPAs that is contingent upon the counterparties meeting specified contract dates for commercial operation. Subsequent to December 31, 2016, the specified contract dates for commercial operation were extended from 2017 to 2019 and may change further as a result of regulatory action. See FUTURE EARNINGS POTENTIAL – "Regulatory Matters – Renewables" herein for additional information.

(l) Includes long-term service agreements, contracts for the procurement of limestone, contractual environmental remediation liabilities, and operation and maintenance agreements. Long-term service agreements include price escalation based on inflation indices.

(m) Projections of nuclear decommissioning trust fund contributions for Plant Hatch and Plant Vogtle Units 1 and 2 are based on the 2013 ARP for Georgia Power. Alabama Power also has external trust funds for nuclear decommissioning costs; however, Alabama Power currently has no additional funding requirements. See Note 1 to the financial statements under "Nuclear Decommissioning" for additional information.

(n) The Southern Company system forecasts contributions to the pension and other postretirement benefit plans over a three-year period. Southern Company anticipates no mandatory contributions to the qualified pension plans 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 corporate assets of Southern Company's subsidiaries. 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 corporate assets of Southern Company's subsidiaries.

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Cautionary Statement Regarding Forward-Looking Statements

Southern Company's 2016 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning regulated rates, the strategic goals for the wholesale business, customer and sales growth, economic conditions, 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 plans, postretirement benefit plans, and nuclear decommissioning trust fund contributions, financing activities, completion dates of construction projects, filings with state and federal regulatory authorities, impact of the PATH Act, federal income tax benefits, 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 environmental laws regulating emissions, discharges, and disposal to air, water, and land, and also changes in tax and other laws and regulations to which Southern Company and its subsidiaries are subject, including potential tax reform legislation, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries;
- the effects, extent, and timing of the entry of additional competition in the markets in which Southern Company's subsidiaries operate;
- variations in demand for electricity and natural gas, 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 natural gas and other fuels;
- limits on pipeline capacity;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development, construction, and operation of facilities, which include the development and construction of generating facilities with designs that have not been finalized or previously constructed, including changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, sustaining nitrogen supply, contractor or supplier delay, non-performance under construction, operating, or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by any PSC);
- the ability to construct facilities in accordance with the requirements of permits and licenses, to satisfy any environmental performance standards and the requirements of tax credits and other incentives, and to integrate facilities into the Southern Company system upon completion of construction;
- investment performance of the Southern Company system's employee and retiree benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- ongoing renewable energy partnerships and development agreements;
-

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;

- legal proceedings and regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals and NRC actions;
- actions related to cost recovery for the Kemper IGCC, including the ultimate impact of the 2015 decision of the Mississippi Supreme Court, the Mississippi PSC's December 2015 rate order, and related legal or regulatory proceedings, Mississippi PSC review of the prudence of Kemper IGCC costs and approval of further permanent rate recovery plans, actions relating to proposed securitization, satisfaction of requirements to utilize grants, and the ultimate impact of the termination of the proposed sale of an interest in the Kemper IGCC to SMEPA;

- the ability to successfully operate the electric utilities' generating, transmission, and distribution facilities and Southern Company Gas' natural gas distribution and storage facilities and the successful performance of necessary corporate functions;
- the inherent risks involved in operating and constructing nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, and financial risks;
- the inherent risks involved in transporting and storing natural gas;
- the performance of projects undertaken by the non-utility businesses and the success of efforts to invest in and develop new opportunities;
- 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 Southern Company or its subsidiaries;
- the possibility that the anticipated benefits from the Merger cannot be fully realized or may take longer to realize than expected, the possibility that costs related to the integration of Southern Company and Southern Company Gas will be greater than expected, the ability to retain and hire key personnel and maintain relationships with customers, suppliers, or other business partners, and the diversion of management time on integration-related issues;
- the ability of counterparties of Southern Company and its subsidiaries 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 Southern Company system'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 Southern Company's and any of its subsidiaries' 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 foreign currency exchange rates, counterparty performance, and the economy in general, as well as potential impacts on the benefits of the DOE loan guarantees;
- the ability of Southern Company's electric utilities 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 Southern Company system's business resulting from incidents affecting the U.S. electric grid, natural gas pipeline infrastructure, or operation of generating or storage 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 Southern Company from time to time with the SEC.

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

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CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2016, 2015, and 2014
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	2016	2015	2014
	(in millions)		
Operating Revenues:			
Retail electric revenues	$15,234	$14,987	$15,550
Wholesale electric revenues	1,926	1,798	2,184
Other electric revenues	698	657	672
Natural gas revenues	1,596	—	—
Other revenues	442	47	61
Total operating revenues	19,896	17,489	18,467
Operating Expenses:			
Fuel	4,361	4,750	6,005
Purchased power	750	645	672
Cost of natural gas	613	—	—
Cost of other sales	260	—	—
Other operations and maintenance	5,240	4,416	4,354
Depreciation and amortization	2,502	2,034	1,945
Taxes other than income taxes	1,113	997	981
Estimated loss on Kemper IGCC	428	365	868
Total operating expenses	15,267	13,207	14,825
Operating Income	4,629	4,282	3,642
Other Income and (Expense):			
Allowance for equity funds used during construction	202	226	245
Earnings from equity method investments	59	—	—
Interest expense, net of amounts capitalized	(1,317)	(840)	(835)
Other income (expense), net	(93)	(39)	(44)
Total other income and (expense)	(1,149)	(653)	(634)
Earnings Before Income Taxes	3,480	3,629	3,008
Income taxes	951	1,194	977
Consolidated Net Income	2,529	2,435	2,031
Less:			
Dividends on preferred and preference stock of subsidiaries	45	54	68
Net income attributable to noncontrolling interests	36	14	—
Consolidated Net Income Attributable to Southern Company	$2,448	$2,367	$1,963
Common Stock Data:			
Earnings per share (EPS) —			
Basic EPS	$2.57	$2.60	$2.19
Diluted EPS	2.55	2.59	2.18
Average number of shares of common stock outstanding — (in millions)			
Basic	951	910	897
Diluted	958	914	901

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

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CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2016, 2015, and 2014
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	2016	2015	2014
	(in millions)		
Consolidated Net Income	$2,529	$2,435	$2,031
Other comprehensive income:			
Qualifying hedges:			
Changes in fair value, net of tax of $(84), $(8), and $(6), respectively	(136)	(13)	(10)
Reclassification adjustment for amounts included in net income, net of tax of $43, $4, and $3, respectively	69	6	5
Pension and other postretirement benefit plans:			
Benefit plan net gain (loss), net of tax of $10, $(1), and $(32), respectively	13	(2)	(51)
Reclassification adjustment for amounts included in net income, net of tax of $3, $4, and $2, respectively	4	7	3
Total other comprehensive income (loss)	(50)	(2)	(53)
Less:			
Dividends on preferred and preference stock of subsidiaries	45	54	68
Comprehensive income attributable to noncontrolling interests	36	14	—
Consolidated Comprehensive Income Attributable to Southern Company	$2,398	$2,365	$1,910

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

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2016, 2015, and 2014
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	2016	2015	2014
		(in millions)	
Operating Activities:			
Consolidated net income	$2,529	$2,435	$2,031
Adjustments to reconcile consolidated net income to net cash provided from operating activities —			
Depreciation and amortization, total	2,923	2,395	2,293
Deferred income taxes	(127)	1,404	709
Collateral deposits	(102)	—	—
Allowance for equity funds used during construction	(202)	(226)	(245)
Pension, postretirement, and other employee benefits	(65)	83	(9)
Pension and postretirement funding	(1,029)	(7)	(506)
Settlement of asset retirement obligations	(171)	(37)	(17)
Stock based compensation expense	121	99	63
Hedge settlements	(233)	(17)	—
Estimated loss on Kemper IGCC	428	365	868
Income taxes receivable, non-current	(122)	(413)	—
Other, net	(36)	(33)	13
Changes in certain current assets and liabilities —			
-Receivables	(544)	243	(352)
-Fossil fuel for generation	178	61	408
-Natural gas for sale	(226)	—	—
-Materials and supplies	(31)	(44)	(67)
-Other current assets	(174)	(108)	(57)
-Accounts payable	301	(353)	267
-Accrued taxes	1,456	352	(105)
-Accrued compensation	36	(41)	255
-Retail fuel cost over recovery — short-term	(231)	289	(23)
-Mirror CWIP	—	(271)	180
-Other current liabilities	215	98	109
Net cash provided from operating activities	4,894	6,274	5,815
Investing Activities:			
Business acquisitions, net of cash acquired	(10,689)	(1,719)	(731)
Property additions	(7,310)	(5,674)	(5,246)
Investment in restricted cash	(733)	(160)	(11)
Distribution of restricted cash	742	154	57
Nuclear decommissioning trust fund purchases	(1,160)	(1,424)	(916)
Nuclear decommissioning trust fund sales	1,154	1,418	914
Cost of removal, net of salvage	(245)	(167)	(170)
Change in construction payables, net	(121)	402	(107)
Investment in unconsolidated subsidiaries	(1,444)	—	—
Prepaid long-term service agreement	(134)	(197)	(181)
Other investing activities	(108)	87	(17)
Net cash used for investing activities	(20,048)	(7,280)	(6,408)
Financing Activities:			
Increase (decrease) in notes payable, net	1,228	73	(676)

Proceeds —			
Long-term debt	16,368	7,029	3,169
Interest-bearing refundable deposit	—	—	125
Common stock	3,758	256	806
Short-term borrowings	—	755	—
Redemptions and repurchases —			
Long-term debt	(3,145)	(3,604)	(816)
Common stock	—	(115)	(5)
Interest-bearing refundable deposits	—	(275)	—
Preferred and preference stock	—	(412)	—
Short-term borrowings	(478)	(255)	—
Distributions to noncontrolling interests	(72)	(18)	(1)
Capital contributions from noncontrolling interests	682	341	8
Purchase of membership interests from noncontrolling interests	(129)	—	—
Payment of common stock dividends	(2,104)	(1,959)	(1,866)
Other financing activities	(383)	(116)	(100)
Net cash provided from financing activities	15,725	1,700	644
Net Change in Cash and Cash Equivalents	571	694	51
Cash and Cash Equivalents at Beginning of Year	1,404	710	659
Cash and Cash Equivalents at End of Year	$1,975	$1,404	$710

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

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CONSOLIDATED BALANCE SHEETS
At December 31, 2016 and 2015
Southern Company and Subsidiary Companies 2016 Annual Report

Assets	2016	2015
	(in millions)	
Current Assets:		
Cash and cash equivalents	$1,975	$1,404
Receivables —		
Customer accounts receivable	1,565	1,058
Energy marketing receivable	623	—
Unbilled revenues	706	397
Under recovered regulatory clause revenues	18	63
Income taxes receivable, current	544	144
Other accounts and notes receivable	377	398
Accumulated provision for uncollectible accounts	(43)	(13)
Materials and supplies	1,462	1,061
Fossil fuel for generation	689	868
Natural gas for sale	631	—
Prepaid expenses	364	495
Other regulatory assets, current	581	580
Other current assets	230	71
Total current assets	9,722	6,526
Property, Plant, and Equipment:		
In service	98,416	75,118
Less accumulated depreciation	29,852	24,253
Plant in service, net of depreciation	68,564	50,865
Other utility plant, net	—	233
Nuclear fuel, at amortized cost	905	934
Construction work in progress	8,977	9,082
Total property, plant, and equipment	78,446	61,114
Other Property and Investments:		
Goodwill	6,251	2
Equity investments in unconsolidated subsidiaries	1,549	6
Other intangible assets, net of amortization of $62 and $12 at December 31, 2016 and December 31, 2015, respectively	970	317
Nuclear decommissioning trusts, at fair value	1,606	1,512
Leveraged leases	774	755
Miscellaneous property and investments	270	160
Total other property and investments	11,420	2,752
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	1,629	1,560
Unamortized loss on reacquired debt	223	227
Other regulatory assets, deferred	6,851	4,989
Income taxes receivable, non-current	11	413
Other deferred charges and assets	1,395	737
Total deferred charges and other assets	10,109	7,926
Total Assets	$109,697	$78,318

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

CONSOLIDATED BALANCE SHEETS
At December 31, 2016 and 2015
Southern Company and Subsidiary Companies 2016 Annual Report

Liabilities and Stockholders' Equity	2016	2015
	(in millions)	
Current Liabilities:		
Securities due within one year	$2,587	$2,674
Notes payable	2,241	1,376
Energy marketing trade payables	597	—
Accounts payable	2,228	1,905
Customer deposits	558	404
Accrued taxes —		
Accrued income taxes	193	9
Unrecognized tax benefits	385	10
Other accrued taxes	667	484
Accrued interest	518	249
Accrued compensation	915	777
Asset retirement obligations, current	378	217
Liabilities from risk management activities, net of collateral	107	156
Acquisitions payable	489	—
Other regulatory liabilities, current	236	278
Over recovered regulatory clause revenues, current	135	106
Other current liabilities	683	484
Total current liabilities	12,917	9,129
Long-Term Debt (See accompanying statements)	42,629	24,688
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	14,092	12,322
Deferred credits related to income taxes	219	187
Accumulated deferred investment tax credits	2,228	1,219
Employee benefit obligations	2,299	2,582
Asset retirement obligations, deferred	4,136	3,542
Unrecognized tax benefits, deferred	—	370
Accrued environmental remediation	397	42
Other cost of removal obligations	2,748	1,162
Other regulatory liabilities, deferred	258	254
Other deferred credits and liabilities	880	678
Total deferred credits and other liabilities	27,257	22,358
Total Liabilities	82,803	56,175
Redeemable Preferred Stock of Subsidiaries (See accompanying statements)	118	118
Redeemable Noncontrolling Interests (See accompanying statements)	164	43
Total Stockholders' Equity (See accompanying statements)	26,612	21,982
Total Liabilities and Stockholders' Equity	$109,697	$78,318
Commitments and Contingent Matters (See notes)		

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

CONSOLIDATED STATEMENTS OF CAPITALIZATION
At December 31, 2016 and 2015
Southern Company and Subsidiary Companies 2016 Annual Report

		2016	2015	2016	2015
		(in millions)		(percent of total)	
Long-Term Debt:					
Long-term debt payable to affiliated trusts —					
Variable rate (3.95% at 1/1/17) due 2042		$206	$206		
Long-term senior notes and debt —					
Maturity	Interest Rates				
2016	1.95% to 5.30%	—	1,360		
2017	1.30% to 7.20%	2,019	1,995		
2018	1.50% to 5.40%	2,353	1,697		
2019	1.85% to 5.55%	3,076	1,176		
2020	2.38% to 4.75%	1,326	1,327		
2021	2.35% to 9.10%	2,655	200		
2022 through 2051	1.00% to 8.70%	21,797	10,972		
Variable rates (0.76% to 3.50% at 1/1/16) due 2016		—	1,278		
Variable rates (1.82% to 3.75% at 1/1/17) due 2017		461	400		
Variable rates (1.88% to 2.24% at 1/1/17) due 2018		1,520	—		
Variable rates (1.87% to 2.10% at 1/1/17) due 2021		25	—		
Variable rate (3.75% at 1/1/17) due 2032 to 2036		15	13		
Total long-term senior notes and debt		35,247	20,418		
Other long-term debt —					
Pollution control revenue bonds —					
Maturity	Interest Rates				
2019	4.55%	25	25		
2022 through 2049	0.65% to 5.15%	1,429	1,509		
Variable rate (0.22% at 1/1/16) due 2016		—	4		
Variable rates (0.77% to 0.87% at 1/1/17) due 2017		76	76		
Variable rates (0.82% to 0.86% at 1/1/17) due 2021		65	65		
Variable rates (0.75% to 0.87% at 1/1/17) due 2022 to 2053		1,739	1,659		
Plant Daniel revenue bonds (7.13%) due 2021		270	270		
FFB loans —					
2.57% to 3.86% due 2020		44	37		
2.57% to 3.86% due 2021		44	37		
2.57% to 3.86% due 2022 to 2044		2,537	2,126		
First mortgage bonds —					
4.70% due 2019		50	—		
2.66% to 6.58% due 2023 to 2038		575	—		
Gas facility revenue bonds —					
Variable rate (1.28% at 1/1/17) due 2022 to 2033		200	—		
Junior subordinated notes (5.25% to 6.25%) due 2057 to 2076		2,350	1,000		
Total other long-term debt		9,404	6,808		
Unamortized fair value adjustment of long-term debt		578	—		
Capitalized lease obligations		136	146		
Unamortized debt premium		52	61		

Unamortized debt discount	(194)	(36)		
Unamortized debt issuance expense	(213)	(241)		
Total long-term debt (annual interest requirement — $1.6 billion)	45,216	27,362		
Less amount due within one year	2,587	2,674		
Long-term debt excluding amount due within one year	42,629	24,688	61.3 %	52.6 %

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CONSOLIDATED STATEMENTS OF CAPITALIZATION (continued)
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	2016	2015	2016	2015
	(in millions)		(percent of total)	
Redeemable Preferred Stock of Subsidiaries:				
Cumulative preferred stock				
$100 par or stated value — 4.20% to 5.44%				
Authorized — 20 million shares				
Outstanding — 1 million shares	81	81		
$1 par value — 5.83%				
Authorized — 28 million shares				
Outstanding — 2 million shares: $25 stated value	37	37		
Total redeemable preferred stock of subsidiaries (annual dividend requirement — $6 million)	118	118	0.2	0.3
Redeemable Noncontrolling Interests	164	43	0.2	0.1
Common Stockholders' Equity:				
Common stock, par value $5 per share —	4,952	4,572		
Authorized — 1.5 billion shares				
Issued — 2016: 991 million shares				
— 2015: 915 million shares				
Treasury — 2016: 0.8 million shares				
— 2015: 3.4 million shares				
Paid-in capital	9,661	6,282		
Treasury, at cost	(31)	(142)		
Retained earnings	10,356	10,010		
Accumulated other comprehensive loss	(180)	(130)		
Total common stockholders' equity	24,758	20,592	35.6	44.0
Preferred and Preference Stock of Subsidiaries and Noncontrolling Interests:				
Non-cumulative preferred stock				
$25 par value — 6.00% to 6.13%				
Authorized — 60 million shares				
Outstanding — 2 million shares	45	45		
Preference stock				
Authorized — 65 million shares				
Outstanding — $1 par value — 6.45% to 6.50% — 8 million shares (non-cumulative)	196	196		
Outstanding — $100 par or stated value — 5.60% to 6.50% — 4 million shares (non-cumulative)	368	368		
Noncontrolling interests	1,245	781		
Total preferred and preference stock of subsidiaries and noncontrolling interests (annual dividend requirement — $39 million)	1,854	1,390	2.7	3.0
Total stockholders' equity	26,612	21,982		
Total Capitalization	$69,523	$46,831	100.0%	100.0%

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

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CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
For the Years Ended December 31, 2016, 2015, and 2014
Southern Company and Subsidiary Companies 2016 Annual Report

	Southern Company Common Stockholders' Equity									
	Number of Common Shares		Common Stock				Accumulated Other Comprehensive Income (Loss)	Preferred and Preference Stock of Subsidiaries	Noncontrolling Interests	Total
	Issued	Treasury	Par Value	Paid-In Capital	Treasury	Retained Earnings				
	(in thousands)		(in millions)							
Balance at December 31, 2013	892,733	(5,647)	$4,461	$5,362	$(250)	$9,510	$(75)	$756	$—	$19,764
Consolidated net income attributable to Southern Company	—	—	—	—	—	1,963	—	—	—	1,963
Other comprehensive income (loss)	—	—	—	—	—	—	(53)	—	—	(53)
Stock issued	15,769	4,996	78	501	227	—	—	—	—	806
Stock-based compensation	—	—	—	86	—	—	—	—	—	86
Cash dividends of $2.0825 per share	—	—	—	—	—	(1,866)	—	—	—	(1,866)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	—	221	221
Net loss attributable to noncontrolling interests	—	—	—	—	—	—	—	—	(2)	(2)
Other	—	(74)	—	6	(3)	2	—	—	2	7
Balance at December 31, 2014	908,502	(725)	4,539	5,955	(26)	9,609	(128)	756	221	20,926
Consolidated net income attributable to Southern Company	—	—	—	—	—	2,367	—	—	—	2,367
Other comprehensive income (loss)	—	—	—	—	—	—	(2)	—	—	(2)
Stock issued	6,571	(2,599)	33	223	—	—	—	—	—	256
Stock-based compensation	—	—	—	100	—	—	—	—	—	100
Stock repurchased, at cost	—	—	—	—	(115)	—	—	—	—	(115)
Cash dividends of $2.1525 per share	—	—	—	—	—	(1,959)	—	—	—	(1,959)
Preference stock redemptions	—	—	—	—	—	—	—	(150)	—	(150)

Contributions from noncontrolling interests	—	—	—	—	—	—	—	—	567	567
Distributions to noncontrolling interests	—	—	—	—	—	—	—	—	(18)	(18)
Net income attributable to noncontrolling interests	—	—	—	—	—	—	—	—	12	12
Other	—	(28)	—	4	(1)	(7)	—	3	(1)	(2)
Balance at December 31, 2015	915,073	(3,352)	4,572	6,282	(142)	10,010	(130)	609	781	21,982
Consolidated net income attributable to Southern Company	—	—	—	—	—	2,448	—	—	—	2,448
Other comprehensive income (loss)	—	—	—	—	—	—	(50)	—	—	(50)
Stock issued	76,140	2,599	380	3,263	115	—	—	—	—	3,758
Stock-based compensation	—	—	—	120	—	—	—	—	—	120
Cash dividends of $2.2225 per share	—	—	—	—	—	(2,104)	—	—	—	(2,104)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	—	618	618
Distributions to noncontrolling interests	—	—	—	—	—	—	—	—	(57)	(57)
Purchase of membership interests from noncontrolling interests	—	—	—	—	—	—	—	—	(129)	(129)
Net income attributable to redeemable noncontrolling interests	—	—	—	—	—	—	—	—	32	32
Other	—	(66)	—	(4)	(4)	2	—	—	—	(6)
Balance at December 31, 2016	991,213	(819)	$4,952	$9,661	$(31)	$10,356	$ (180)	$ 609	$ 1,245	$26,612

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

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Southern Company and Subsidiary Companies 2016 Annual Report

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Southern Company and Subsidiary Companies 2016 Annual Report

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES
General
The Southern Company (Southern Company or the Company) is the parent company of four traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), SCS, Southern LINC, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, PowerSecure (as of May 9, 2016), and other direct and indirect subsidiaries. The traditional electric operating companies – Alabama Power, Georgia Power, Gulf Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. Southern Company Gas distributes natural gas through the natural gas distribution utilities in seven states and is involved in several other complementary businesses including gas marketing services, wholesale gas services, and gas midstream operations. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. Southern LINC 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. PowerSecure is a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure.
The financial statements reflect Southern Company's investments in the subsidiaries on a consolidated basis. The equity method is used for entities in which the Company has significant influence but does not control and for variable interest entities where the Company has an equity investment but is not the primary beneficiary. Intercompany transactions have been eliminated in consolidation.
The traditional electric operating companies, Southern Power, certain subsidiaries of Southern Company Gas, and certain other subsidiaries are subject to regulation by the FERC, and the traditional electric operating companies and natural gas distribution utilities are also subject to regulation by their respective state PSCs or other applicable state regulatory agencies. As such, the consolidated financial statements reflect the effects of rate regulation in accordance with GAAP and comply with the accounting policies and practices prescribed by relevant state PSCs or other applicable state regulatory agencies. 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. These reclassifications had no impact on Southern Company's results of operations, financial position, or cash flows.
In June 2015, Georgia Power identified an error affecting the billing to a small number of large commercial and industrial customers under a rate plan allowing for variable demand-driven pricing from January 1, 2013 to June 30, 2015. In the second quarter 2015, Georgia Power recorded an out of period adjustment of approximately $75 million to decrease retail revenues, resulting in a decrease to net income of approximately $47 million. Georgia Power evaluated the effects of this error on the interim and annual periods that included the billing error. Based on an analysis of qualitative and quantitative factors, Georgia Power determined the error was not material to any affected period and, therefore, an amendment of previously filed financial statements was not required.
Recently Issued Accounting Standards
In 2014, the FASB issued ASC 606, Revenue from Contracts with Customers, replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the guidance is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

While Southern Company expects most of its revenue to be included in the scope of ASC 606, it has not fully completed its evaluation of such arrangements. The majority of Southern Company's revenue, including energy provided to customers, is from tariff offerings that provide natural gas or electricity without a defined contractual term. For such arrangements, Southern Company generally expects that the revenue from contracts with these customers will continue to be equivalent to the electricity or natural gas supplied and billed in that period (including unbilled revenues) and the adoption of ASC 606 will not result in a significant shift in the timing of revenue recognition for such sales.

Southern Company's ongoing evaluation of other revenue streams and related contracts includes longer term contractual commitments and unregulated sales to customers. Some revenue arrangements, such as certain PPAs and alternative revenue programs, are expected to be excluded from the scope of ASC 606 and therefore, be accounted for and presented separately from revenues under ASC 606 on Southern Company's financial statements. In addition, the power and utilities industry is currently addressing other specific industry issues, including the applicability of ASC 606 to contributions in aid of construction (CIAC). If

final implementation guidance indicates CIAC will be accounted for under ASC 606 and offsetting regulatory treatment is not permitted, it could have a material impact on Southern Company's financial statements.
The new standard is effective for interim and annual reporting periods beginning after December 15, 2017. Southern Company must select a transition method to be applied either retrospectively to each prior reporting period presented or retrospectively with a cumulative effect adjustment to retained earnings at the date of initial adoption. As the ultimate impact of the new standard has not yet been determined, Southern Company has not elected its transition method.
On February 25, 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842) (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged and there is no change to the accounting for existing leveraged leases. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. Southern Company is currently evaluating the new standard and has not yet determined its ultimate impact; however, adoption of ASU 2016-02 is expected to have a significant impact on Southern Company's balance sheet.
On March 30, 2016, the FASB issued ASU No. 2016-09, Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting (ASU 2016-09). ASU 2016-09 changes the accounting for income taxes and the cash flow presentation for share-based payment award transactions effective for fiscal years beginning after December 15, 2016. The new guidance requires all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation to be recognized as income tax expense or benefit in the income statement. Previously, Southern Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities rather than net cash provided from financing activities on the statement of cash flows. Southern Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. Southern Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of Southern Company. See Notes 5, 8, and 14 for disclosures impacted by ASU 2016-09.
On October 24, 2016, the FASB issued ASU No. 2016-16, Income Taxes (Topic 740), Intra-Entity Transfers of Assets Other Than Inventory (ASU 2016-16). Current GAAP prohibits the recognition of current and deferred income taxes for an affiliate asset transfer until the asset has been sold to an outside party. ASU 2016-16 requires an entity to recognize the income tax consequences of an affiliate transfer of an asset other than inventory when the transfer occurs. ASU 2016-16 is effective for annual reporting periods beginning after December 15, 2017 and interim periods within those annual periods. The amendments will be applied on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. Southern Company is currently assessing the impact of the standard on its financial statements and has not yet determined its ultimate impact.
On November 17, 2016, the FASB issued ASU No. 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash (ASU 2016-18). ASU 2016-18 eliminates the need to reflect transfers between cash and restricted cash in operating, investing, and financing activities in the statement of cash flows. Upon adoption, the net change in cash and cash equivalents during the period will include amounts generally described as restricted cash or restricted cash equivalents. ASU 2016-18 is effective for fiscal years beginning after December 15, 2017, with early adoption permitted, and will be applied retrospectively to each period presented. Southern Company does not intend to adopt the guidance early. The adoption of ASU 2016-18 will not have a material impact on the financial statements of Southern Company.
Regulatory Assets and Liabilities

The traditional electric operating companies and natural gas distribution utilities are subject to accounting requirements 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.

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

	2016	2015	Note
	(in millions)		
Retiree benefit plans	$3,959	$3,440	(a,n)
Deferred income tax charges	1,590	1,514	(b)
Asset retirement obligations-asset	1,080	481	(b,n)
Environmental remediation-asset	491	78	(j,n)
Other regulatory assets	355	299	(k)
Remaining net book value of retired assets	351	283	(o)
Under recovered regulatory clause revenues	273	142	(g)
Loss on reacquired debt	243	248	(c)
Property damage reserves-asset	206	92	(i)
Kemper IGCC	201	216	(h)
Vacation pay	182	178	(f,n)
Long-term debt fair value adjustment	155	—	(p)
Deferred PPA charges	141	163	(e,n)
Nuclear outage	97	88	(g)
Fuel-hedging-asset	35	225	(d,n)
Other cost of removal obligations	(2,774)	(1,177)	(b)
Deferred income tax credits	(219)	(187)	(b)
Over recovered regulatory clause revenues	(203)	(261)	(g)
Property damage reserves-liability	(177)	(178)	(l)
Other regulatory liabilities	(110)	(35)	(m)
Asset retirement obligations-liability	(10)	(45)	(b,n)
Total regulatory assets (liabilities), net	$5,866	$5,564	

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

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

(b) Asset retirement and other cost of removal obligations 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 70 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities.

(c) Recovered over either the remaining life of the original issue or, if refinanced, over the remaining life of the new issue, which may range up to 50 years.

(d) Recorded over the life of the underlying hedged purchase contracts, which generally do not exceed five years. Upon final settlement, actual costs incurred are recovered through fuel and energy cost recovery mechanisms.

(e) Recovered over the life of the PPA for periods up to seven years.

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

(g) Recorded and recovered or amortized as approved or accepted by the appropriate state PSCs or other applicable regulatory agencies over periods generally not exceeding ten years.

(h) Includes $97 million of regulatory assets currently in rates to be recovered over periods of two, seven, or 10 years. For additional information, see Note 3 under "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – Regulatory Assets and Liabilities."

(i) Previous under-recovery as of December 2013 is recorded and recovered or amortized as approved by the Georgia PSC through 2019. Amortization of $185 million related to the under-recovery from January 2014 through December 2016 will be determined by the Georgia PSC in the 2019 base rate case. See Note 3 for additional information.

(j) Recovered through environmental cost recovery mechanisms when the remediation is performed or the work is performed.

(k) Comprised of numerous immaterial components including deferred income tax charges - Medicare subsidy, cancelled construction projects, building and generating plant leases, property tax, and other miscellaneous assets. These costs are recorded and recovered or amortized as approved by the appropriate state PSCs over periods generally not exceeding 50 years.

(l) Recovered as storm restoration and potential reliability-related expenses are incurred as approved by the appropriate state PSCs.

(m) Comprised of numerous immaterial components including retiree benefit plans, fuel-hedging gains, and other liabilities that are recorded and recovered or amortized as approved by the appropriate state PSCs or other applicable regulatory agencies generally over periods not exceeding 4 years.

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

(o) Amortized as approved by the appropriate state PSCs over periods generally up to 11 years.

(p) Recorded in relation to the Merger. Recovered over the remaining life of the original debt issuances, which range up to 22 years. For additional information see Note 12 under "Southern Company – Merger with Southern Company Gas."

In the event that a portion of a traditional electric operating company's or a natural gas distribution utility's operations is no longer subject to applicable accounting rules for rate regulation, such 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 traditional electric operating company or natural gas distribution utility 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 "Regulatory Matters – Alabama Power," "Regulatory Matters – Georgia Power," "Regulatory Matters – Gulf Power," "Regulatory Matters – Southern Company Gas," and "Integrated Coal Gasification Combined Cycle" 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. Retail rates for the traditional electric operating companies and natural gas distribution utilities may include provisions to adjust billings for fluctuations in fuel and purchased gas 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.

Southern Company's electric utility subsidiaries and Southern Company Gas have 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.

Income and Other Taxes

Southern Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income. In accordance with regulatory requirements, deferred federal ITCs for the traditional electric operating companies and Southern Company Gas are amortized over the average lives of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Under current tax law, certain projects at Southern Power are eligible for federal ITCs or cash grants. Southern Power has elected to receive ITCs. The credits are recorded as a deferred credit and are amortized to income tax expense over the life of the asset. Furthermore, the tax basis of the asset is reduced by 50% of the credits received, resulting in a net deferred tax asset. Southern Power has elected to recognize the tax benefit of this basis difference as a reduction to income tax expense in the year in which the plant reaches commercial operation. In addition, certain projects are eligible for federal PTCs, which are recorded to income tax expense based on KWH production.

Federal ITCs and PTCs, as well as state ITCs and other state tax credits available to reduce income taxes payable, were not fully utilized in 2016 and will be carried forward and utilized in future years. In addition, Southern Company is expected to have a consolidated federal net operating loss (NOL) carryforward for the 2016 tax year along with various state NOL carryforwards, which could result in income tax benefits in the future, if utilized. See Note 5 under "Current and Deferred Income Taxes – Tax Credit Carryforwards" and " – Net Operating Loss" for additional information.

Southern 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.

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

	2016	2015
	(in millions)	
Electric utilities:		
Generation	$48,836	$41,648
Transmission	11,156	10,544
Distribution	18,418	17,670
General	4,629	4,377
Plant acquisition adjustment	126	123
Electric utility plant in service	83,165	74,362
Natural gas distribution utilities:		
Transportation and distribution	11,996	—
Utility plant in service	95,161	74,362
Information technology equipment and software	544	222
Communications equipment	424	418
Storage facilities	1,463	—
Other	824	116
Total other plant in service	3,255	756
Total plant in service	$98,416	$75,118

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 state PSC orders. Alabama Power and Georgia Power defer and amortize nuclear refueling costs over the unit's operating cycle. The refueling cycles for Alabama Power's Plant Farley and Georgia Power's Plants Hatch and Vogtle Units 1 and 2 range from 18 to 24 months, depending on the unit.

Assets acquired under a capital lease are included in property, plant, and equipment and are further detailed in the table below:

	Asset Balances at December 31, 2016	2015
	(in millions)	
Office building	$61	$61
Nitrogen plant	83	83
Computer-related equipment	63	61
Gas pipeline	6	6
Less: Accumulated amortization	(69)	(59)
Balance, net of amortization	$144	$152

The amount of non-cash property additions recognized for the years ended December 31, 2016, 2015, and 2014 was $1.5 billion, $844 million, and $528 million, respectively. These amounts are comprised of construction-related accounts payable outstanding at each year end. Also, the amount of non-cash property additions associated with capitalized leases for the years ended December 31, 2016, 2015, and 2014 was $18 million, $13 million, and $25 million, respectively.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.0% in 2016 and 2015 and 3.1% in 2014. Depreciation studies are conducted periodically to update the composite rates. These studies are filed with the respective state PSC or other applicable state and federal regulatory agencies for the traditional electric operating companies and natural gas distribution utilities. Accumulated depreciation for utility plant in service totaled $29.3 billion and $23.7 billion at December 31, 2016 and 2015, respectively. 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. Certain of Southern Power's generation assets are depreciated on a units-of-production basis, using hours or starts, to better match outage and maintenance costs to the usage of and revenues from these assets. Cost, net of salvage value, of these assets is depreciated on an hours or starts units-of-production basis.

Under the terms of the 2013 ARP, Georgia Power amortized approximately $14 million in each of 2014, 2015, and 2016 of its remaining regulatory liability related to other cost of removal obligations.

See Note 3 under "Regulatory Matters – Gulf Power – Retail Base Rate Cases" for information regarding depreciation and amortization adjustments related to the other cost of removal regulatory liability.

Depreciation of the original cost of other plant in service is provided primarily on a straight-line basis over estimated useful lives ranging from three to 65 years. Accumulated depreciation for other plant in service totaled $550 million and $510 million at December 31, 2016 and 2015, respectively.

Asset Retirement Obligations and Other Costs of Removal

AROs 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. Each traditional electric operating company and natural gas distribution utility has received accounting guidance from its state PSC or applicable state regulatory agency allowing the continued accrual or recovery of other retirement costs for long-lived assets that it 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 and amounts to be recovered are reflected in the balance sheet as a regulatory asset.

The liability for AROs primarily relates to facilities that are subject to the Disposal of Coal Combustion Residuals from Electric Utilities final rule published by the EPA in April 2015 (CCR Rule), principally ash ponds, and the decommissioning of the Southern Company system's nuclear facilities – Alabama Power's Plant Farley and Georgia Power's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2. In addition, the Southern Company system has retirement obligations related to various landfill sites, asbestos removal, mine reclamation, land restoration related to solar and wind facilities, and disposal of polychlorinated biphenyls in certain transformers. The Southern Company system also has identified retirement obligations related to certain electric transmission and distribution facilities, certain wireless communication towers, property associated with the Southern Company system's rail lines and natural gas pipelines, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded as 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 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 various state PSCs, 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:

	2016	2015
	(in millions)	
Balance at beginning of year	$3,759	$2,201

Liabilities incurred	66	662
Liabilities settled	(171)	(37)
Accretion	162	115
Cash flow revisions	698	818
Balance at end of year	$4,514	$3,759

The increases in cash flow revisions and liabilities incurred in 2016 primarily relate to changes in ash pond closure strategy. The cash flow revisions in 2015 are primarily related to an increase in AROs associated with facilities impacted by the CCR Rule and Georgia Power's updated nuclear decommissioning study.

The cost estimates for AROs related to the CCR Rule are based on information as of December 31, 2016 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. 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 with respect to compliance activities, including the potential for closing ash ponds prior to the end of their currently anticipated useful life, the traditional electric operating companies expect to continue to periodically update these estimates.

Nuclear Decommissioning

The NRC requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. Alabama Power and Georgia Power have 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 state PSCs, as well as the IRS. While Alabama Power and Georgia Power are allowed to prescribe an overall investment policy to the Funds' managers, neither Southern Company nor its subsidiaries or affiliates are 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 Southern Company, Alabama Power, and Georgia Power. 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.

Southern Company records the investment securities held in the Funds at fair value, as disclosed in Note 10, as management believes that fair value best represents the nature of the Funds. Gains and losses, whether realized or unrealized, are recorded in the regulatory liability for AROs in the balance sheets and are not included in net income or OCI. Fair value adjustments and realized gains and losses are determined on a specific identification basis.

The Funds at Georgia Power participate in a securities lending program through the managers of the Funds. Under this program, the Funds' investment securities are loaned to institutional investors for a fee. Securities loaned are fully collateralized by cash, letters of credit, and/or securities issued or guaranteed by the U.S. government or its agencies or instrumentalities. As of December 31, 2016 and 2015, approximately $56 million and $76 million, respectively, of the fair market value of the Funds' securities were on loan and pledged to creditors under the Funds' managers' securities lending program. The fair value of the collateral received was approximately $58 million and $78 million at December 31, 2016 and 2015, respectively, and can only be sold by the borrower upon the return of the loaned securities. The collateral received is treated as a non-cash item in the statements of cash flows.

At December 31, 2016, investment securities in the Funds totaled $1.6 billion, consisting of equity securities of $878 million, debt securities of $685 million, and $41 million of other securities. At December 31, 2015, investment securities in the Funds totaled $1.5 billion, consisting of equity securities of $817 million, debt securities of $654 million, and $38 million of other securities. These amounts include the investment securities pledged to creditors and collateral received and exclude receivables related to investment income and pending investment sales and payables related to pending investment purchases and the lending pool.

Sales of the securities held in the Funds resulted in cash proceeds of $1.2 billion, $1.4 billion, and $0.9 billion in 2016, 2015, and 2014, respectively, all of which were reinvested. For 2016, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $114 million, which included $48 million related to unrealized gains on securities held in the Funds at December 31, 2016. For 2015, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $11 million, which included $83 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 $98 million, which included $19 million related to unrealized gains and losses on securities held in the Funds at December 31, 2014. 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.

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For Alabama Power, approximately $19 million and $20 million at December 31, 2016 and 2015, respectively, previously recorded in internal reserves is being transferred into the Funds through 2040 as 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. Alabama Power and Georgia Power have filed plans with the NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.
At December 31, 2016 and 2015, the accumulated provisions for the external decommissioning trust funds were as follows:

	External Trust Funds	
	2016	2015
	(in millions)	
Plant Farley	$790	$734
Plant Hatch	511	487
Plant Vogtle Units 1 and 2	303	288

Site study cost is the estimate to decommission a specific facility as of the site study year. The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from these estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates. The estimated costs of decommissioning as of December 31, 2016 based on the most current studies, which were performed in 2013 for Alabama Power's Plant Farley and in 2015 for the Georgia Power plants, were as follows for Alabama Power's Plant Farley and Georgia Power's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2:

	Plant Farley	Plant Hatch	Plant Vogtle Units 1 and 2
Decommissioning periods:			
Beginning year	2037	2034	2047
Completion year	2076	2075	2079
	(in millions)		
Site study costs:			
Radiated structures	$1,362	$ 678	$ 568
Spent fuel management	—	160	147
Non-radiated structures	80	64	89
Total site study costs	$1,442	$ 902	$ 804

For ratemaking purposes, Alabama Power's decommissioning costs are based on the site study, and Georgia Power's decommissioning costs are based on the NRC generic estimate to decommission the radioactive portion of the facilities and the site study estimate for spent fuel management as of 2012. Under the 2013 ARP, the Georgia PSC approved Georgia Power's annual decommissioning cost for ratemaking of $4 million and $2 million for Plant Hatch and Plant Vogtle Units 1 and 2, respectively. Georgia Power expects the Georgia PSC to review and adjust, if necessary, the amounts collected in rates for nuclear decommissioning costs in Georgia Power's 2019 base rate case.
Significant assumptions used to determine these costs for ratemaking were an inflation rate of 4.5% and 2.4% for Alabama Power and Georgia Power, respectively, and a trust earnings rate of 7.0% and 4.4% for Alabama Power and Georgia Power, respectively.
Amounts previously contributed to the Funds for Plant Farley are currently projected to be adequate to meet the decommissioning obligations. Alabama Power 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 and Interest Capitalized

The traditional electric operating companies and certain of the natural gas distribution utilities record 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, 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. Interest related to the construction of new facilities not included in the traditional electric operating companies' and natural gas distribution utilities' regulated rates is capitalized in accordance with standard interest capitalization requirements. AFUDC and interest capitalized, net of income taxes were 11.4%, 12.8%, and 16.0% of net income for 2016, 2015, and 2014, respectively.

Cash payments for interest totaled $1.1 billion, $809 million, and $732 million in 2016, 2015, and 2014, respectively, net of amounts capitalized of $125 million, $124 million, and $111 million, respectively.

Impairment of Long-Lived Assets

Southern 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. See Note 3 under "Integrated Coal Gasification Combined Cycle – Kemper IGCC Schedule and Cost Estimate" for additional information.

Goodwill and Other Intangible Assets and Liabilities

At December 31, 2016 and 2015, goodwill was $6.3 billion and $2 million, respectively. The increase in goodwill relates to Southern Company's acquisitions of PowerSecure and Southern Company Gas. See Note 12 under "Southern Company – Acquisition of PowerSecure" and " – Merger with Southern Company Gas" for additional information. Goodwill is not amortized, but is subject to an annual impairment test during the fourth quarter of each year, or more frequently if impairment indicators arise. Southern Company evaluated its goodwill in the fourth quarter 2016 and determined that no impairment was required.

At December 31, 2016, other intangible assets were as follows:

	Estimated Useful Life	Gross Carrying Amount	Accumulated Amortization	Other Intangible Assets, Net
		(in millions)		
Other intangible assets subject to amortization:				
Customer relationships	11-26 years	$268	$ (32)	$ 236
Trade names	5-28 years	158	(5)	153
Patents	3-10 years	4	—	4
Backlog	5 years	5	(1)	4
Storage and transportation contracts	1-5 years	64	(2)	62
Software and other	1-12 years	2	—	2
PPA fair value adjustments	19-20 years	456	(22)	434
Total other intangible assets subject to amortization		$957	$ (62)	$ 895
Other intangible assets not subject to amortization:				
Federal Communications Commission licenses		75	—	75
Total other intangible assets		$1,032	$ (62)	$ 970

At December 31, 2015, other intangible assets consisted of Southern Power's PPA fair value adjustments with a net carrying amount of $317 million. The increase in other intangible assets primarily relates to Southern Company's acquisitions of PowerSecure and Southern Company Gas, as well as additional PPA fair value adjustments resulting from Southern Power's acquisitions.

Amortization associated with other intangible assets in 2016, 2015, and 2014 was $50 million, $3 million, and $3 million, respectively.

As of December 31, 2016, the estimated amortization associated with other intangible assets is as follows:

	Amortization (in millions)
2017	$ 108
2018	93
2019	74
2020	63
2021	56

Included in other deferred credits and liabilities on the balance sheet is $91 million of intangible liabilities that were recorded during acquisition accounting for transportation contracts at Southern Company Gas. At December 31, 2016, the accumulated amortization of these intangible liabilities was $21 million. The estimated amortization associated with the intangible liabilities that will be recorded in natural gas revenues is as follows:

	Amortization (in millions)
2017	$ 29
2018	24
2019	17

See Note 12 under "Southern Company – Acquisition of PowerSecure" and " – Merger with Southern Company Gas" for additional information. Also see Note 12 under "Southern Power" for additional information regarding Southern Power's PPA fair value adjustments.

Storm Damage Reserves

Each traditional electric operating company maintains a reserve to cover or is allowed to defer and recover the cost of damages from major storms to its transmission and distribution lines and generally the cost of uninsured damages to its generation facilities and other property. In accordance with their respective state PSC orders, the traditional electric operating companies accrued $40 million in each of 2016, 2015, and 2014. Alabama Power, Gulf Power, and Mississippi Power also have authority based on orders from their state PSCs to accrue certain additional amounts as circumstances warrant. In 2016, 2015, and 2014, there were no such additional accruals. See Note 3 under "Regulatory Matters – Alabama Power – Rate NDR" and "Regulatory Matters – Georgia Power – Storm Damage Recovery" for additional information regarding Alabama Power's NDR and Georgia Power's deferred storm costs, respectively.

Leveraged Leases

Southern Company has several leveraged lease agreements, with original terms ranging up to 45 years, which relate to international and domestic energy generation, distribution, and transportation assets. Southern Company receives federal income tax deductions for depreciation and amortization, as well as interest on long-term debt related to these investments. Southern Company reviews all important lease assumptions at least annually, or more frequently if events or changes in circumstances indicate that a change in assumptions has occurred or may occur. These assumptions include the effective tax rate, the residual value, the credit quality of the lessees, and the timing of expected tax cash flows.

Southern Company's net investment in domestic and international leveraged leases consists of the following at December 31:

	2016	2015
	(in millions)	
Net rentals receivable	$1,481	$1,487
Unearned income	(707)	(732)
Investment in leveraged leases	774	755
Deferred taxes from leveraged leases	(309)	(303)

Net investment in leveraged leases	$465	$452

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A summary of the components of income from the leveraged leases follows:

	2016	2015	2014
	(in millions)		
Pretax leveraged lease income	$25	$20	$24
Income tax expense	(9)	(7)	(9)
Net leveraged lease income	$16	$13	$15

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 of the electric utilities. Fuel is recorded to inventory when purchased and then expensed, at weighted average cost, as used and recovered by the traditional electric operating companies through fuel cost recovery rates approved by each state PSC. Emissions allowances granted by the EPA are included in inventory at zero cost.
Natural Gas for Sale
The natural gas distribution utilities, with the exception of Nicor Gas, carry natural gas inventory on a weighted average cost of gas (WACOG) basis.
Nicor Gas' natural gas inventory is carried at cost on a last-in, first-out (LIFO) basis. Inventory decrements occurring during the year that are restored prior to year-end are charged to cost of natural gas at the estimated annual replacement cost. Inventory decrements that are not restored prior to year-end are charged to cost of natural gas at the actual LIFO cost of the inventory layers liquidated. The cost of natural gas, including inventory costs, is recovered from customers under a purchased gas recovery mechanism adjusted for differences between actual costs and amounts billed; therefore, LIFO liquidations have no impact on Southern Company's net income.
Natural gas inventories for Southern Company Gas' non-utility businesses are carried at the lower of weighted average cost or current market price, with cost determined on a WACOG basis. For any declines in market prices below the WACOG considered to be other than temporary, an adjustment is recorded to reduce the value of natural gas inventories to market value.
Financial Instruments
Southern Company and its subsidiaries use derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, electricity purchases and sales, and occasionally foreign currency exchange rates. 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 Southern Company system'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 traditional electric operating companies' and the natural gas distribution utilities' fuel-hedging programs result in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts that qualify as fair value hedges are marked to market through current period income and are recorded on a net basis in the statements of income. Cash flows from derivatives are classified on the statements of cash flows in the same category as the hedged item. See Note 11 for additional information regarding derivatives.

Beginning in 2016, the Company offsets fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. At December 31, 2016, the amount included in accounts payable in the

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balance sheets that the Company has recognized for the obligation to return cash collateral arising from derivative instruments was immaterial.

Southern 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 marketable securities, certain changes in pension and other postretirement benefit plans, reclassifications for amounts included in net income, and dividends on preferred and preference stock of subsidiaries.

Accumulated OCI (loss) balances, net of tax effects, were as follows:

	Qualifying Hedges	Marketable Securities	Pension and Other Postretirement Benefit Plans	Accumulated Other Comprehensive Income (Loss)
	(in millions)			
Balance at December 31, 2015	$(48)	$ —	$ (82)	$ (130)
Current period change	(67)	—	17	(50)
Balance at December 31, 2016	$(115)	$ —	$ (65)	$ (180)

2. RETIREMENT BENEFITS

Southern Company has a defined benefit, trusteed, pension plan covering substantially all employees, with the exception of employees at Southern Company Gas, as discussed below, and PowerSecure. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). On December 19, 2016, the traditional electric operating companies and certain other subsidiaries voluntarily contributed an aggregate of $900 million to Southern Company's qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2017. Southern 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, Southern Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The traditional electric operating companies fund related other postretirement trusts to the extent required by their respective regulatory commissions. For the year ending December 31, 2017, no other postretirement trust contributions are expected.

In addition, Southern Company Gas has a qualified defined benefit, trusteed, pension plan covering certain eligible employees, which was closed in 2012 to new employees. This qualified pension plan is funded in accordance with requirements of ERISA. Southern Company Gas voluntarily contributed $125 million to its qualified pension plan on September 12, 2016. No mandatory contributions to the Southern Company Gas qualified pension plan are anticipated for the year ending December 31, 2017. Southern Company Gas also provides certain non-qualified defined benefit and defined contribution 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, Southern Company Gas provides certain medical care and life insurance benefits for eligible retired employees through a postretirement benefit plan. Southern Company Gas also has a separate unfunded supplemental retirement health care plan that provides medical care and life insurance benefits to employees of discontinued businesses. For the year ending December 31, 2017, no other postretirement trust contributions are expected.

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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:	2016	2015	2014
Pension plans			
Discount rate – benefit obligations	4.58%	4.17%	5.02%
Discount rate – interest costs	3.88	4.17	5.02
Discount rate – service costs	4.98	4.48	5.02
Expected long-term return on plan assets	8.16	8.20	8.20
Annual salary increase	4.37	3.59	3.59
Other postretirement benefit plans			
Discount rate – benefit obligations	4.38%	4.04%	4.85%
Discount rate – interest costs	3.66	4.04	4.85
Discount rate – service costs	4.85	4.39	4.85
Expected long-term return on plan assets	6.66	6.97	7.15
Annual salary increase	4.37	3.59	3.59

Assumptions used to determine benefit obligations:	2016	2015
Pension plans		
Discount rate	4.40%	4.67%
Annual salary increase	4.37	4.46
Other postretirement benefit plans		
Discount rate	4.23%	4.51%
Annual salary increase	4.37	4.46

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

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2016 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate is Reached
Pre-65	6.50 %	4.50 %	2025
Post-65 medical	5.00	4.50	2025
Post-65 prescription	10.00	4.50	2025

NOTES (continued)
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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, 2016 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$128	$ 110
Service and interest costs	4	3

Pension Plans

The total accumulated benefit obligation for the pension plans was $11.3 billion at December 31, 2016 and $9.6 billion at December 31, 2015. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2016 and 2015 were as follows:

	2016	2015
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$10,542	$10,909
Acquisitions	1,244	—
Service cost	262	257
Interest cost	422	445
Benefits paid	(466)	(487)
Actuarial (gain) loss	381	(582)
Balance at end of year	12,385	10,542
Change in plan assets		
Fair value of plan assets at beginning of year	9,234	9,690
Acquisitions	837	—
Actual return (loss) on plan assets	902	(14)
Employer contributions	1,076	45
Benefits paid	(466)	(487)
Fair value of plan assets at end of year	11,583	9,234
Accrued liability	$(802)	$(1,308)

At December 31, 2016, the projected benefit obligations for the qualified and non-qualified pension plans were $11.8 billion and $627 million, respectively. All pension plan assets are related to the qualified pension plans.

Amounts presented in the following tables do not include regulatory assets of $369 million recognized by Southern Company Gas associated with its pension plans prior to its acquisition on July 1, 2016.

Amounts recognized in the balance sheets at December 31, 2016 and 2015 related to the Company's pension plans consist of the following:

	2016	2015
	(in millions)	
Other regulatory assets, deferred	$3,207	$2,998
Other current liabilities	(53)	(46)
Employee benefit obligations	(749)	(1,262)
Other regulatory liabilities, deferred	(87)	—
Accumulated OCI	100	125

NOTES (continued)
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Presented below are the amounts included in accumulated OCI and regulatory assets at December 31, 2016 and 2015 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 2017.

	Prior Service Cost	Net (Gain) Loss
	(in millions)	
Balance at December 31, 2016:		
Accumulated OCI	$4	$96
Regulatory assets	51	3,069
Total	$55	$3,165
Balance at December 31, 2015:		
Accumulated OCI	$3	$122
Regulatory assets	27	2,971
Total	$30	$3,093
Estimated amortization in net periodic pension cost in 2017:		
Accumulated OCI	$1	$7
Regulatory assets	11	155
Total	$12	$162

The components of OCI and the changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2016 and 2015 are presented in the following table:

	Accumulated OCI	Regulatory Assets
	(in millions)	
Balance at December 31, 2014	$134	$ 3,073
Net (gain) loss	1	155
Reclassification adjustments:		
Amortization of prior service costs	(1)	(24)
Amortization of net gain (loss)	(9)	(206)
Total reclassification adjustments	(10)	(230)
Total change	(9)	(75)
Balance at December 31, 2015	$125	$ 2,998
Net (gain) loss	(20)	243
Change in prior service costs	2	37
Reclassification adjustments:		
Amortization of prior service costs	(1)	(13)
Amortization of net gain (loss)	(6)	(145)
Total reclassification adjustments	(7)	(158)
Total change	(25)	122
Balance at December 31, 2016	$100	$ 3,120

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

	2016	2015	2014
	(in millions)		
Service cost	$262	$257	$213
Interest cost	422	445	435
Expected return on plan assets	(782)	(724)	(645)
Recognized net (gain) loss	150	215	110
Net amortization	14	25	26
Net periodic pension cost	$66	$218	$139

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, 2016, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2017	$ 571
2018	593
2019	620
2020	646
2021	666
2022 to 2026	3,673

NOTES (continued)
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Other Postretirement Benefits
Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2016 and 2015 were as follows:

	2016	2015
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$1,989	$1,986
Acquisitions	338	—
Service cost	22	23
Interest cost	76	78
Benefits paid	(119)	(102)
Actuarial (gain) loss	(16)	(38)
Plan amendments	—	34
Retiree drug subsidy	7	8
Balance at end of year	2,297	1,989
Change in plan assets		
Fair value of plan assets at beginning of year	833	900
Acquisitions	100	—
Actual return (loss) on plan assets	58	(12)
Employer contributions	65	39
Benefits paid	(112)	(94)
Fair value of plan assets at end of year	944	833
Accrued liability	$(1,353)	$(1,156)

Amounts presented in the following tables do not include regulatory assets of $77 million recognized by Southern Company Gas associated with its other postretirement benefit plan prior to its acquisition on July 1, 2016.
Amounts recognized in the balance sheets at December 31, 2016 and 2015 related to the Company's other postretirement benefit plans consist of the following:

	2016	2015
	(in millions)	
Other regulatory assets, deferred	$419	$433
Other current liabilities	(4)	(4)
Employee benefit obligations	(1,349)	(1,152)
Other regulatory liabilities, deferred	(41)	(22)
Accumulated OCI	7	8

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NOTES (continued)
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Presented below are the amounts included in accumulated OCI and net regulatory assets (liabilities) at December 31, 2016 and 2015 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 2017.

	Prior Service Cost	Net (Gain) Loss
	(in millions)	
Balance at December 31, 2016:		
Accumulated OCI	$—	$ 7
Net regulatory assets	25	353
Total	$25	$ 360
Balance at December 31, 2015:		
Accumulated OCI	$—	$ 8
Net regulatory assets	32	379
Total	$32	$ 387
Estimated amortization as net periodic postretirement benefit cost in 2017:		
Net regulatory assets	$6	$ 13

The components of OCI, along with the changes in the balance of net regulatory assets (liabilities), related to the other postretirement benefit plans for the plan years ended December 31, 2016 and 2015 are presented in the following table:

	Accumulated OCI	Net Regulatory Assets (Liabilities)
	(in millions)	
Balance at December 31, 2014	$ 8	$ 366
Net (gain) loss	—	33
Change in prior service costs	—	33
Reclassification adjustments:		
Amortization of prior service costs	—	(4)
Amortization of net gain (loss)	—	(17)
Total reclassification adjustments	—	(21)
Total change	—	45
Balance at December 31, 2015	$ 8	$ 411
Net (gain) loss	(1)	(13)
Reclassification adjustments:		
Amortization of prior service costs	—	(6)
Amortization of net gain (loss)	—	(14)
Total reclassification adjustments	—	(20)
Total change	(1)	(33)
Balance at December 31, 2016	$ 7	$ 378

NOTES (continued)
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Components of the other postretirement benefit plans' net periodic cost were as follows:

	2016	2015	2014
	(in millions)		
Service cost	$22	$23	$21
Interest cost	76	78	79
Expected return on plan assets	(60)	(58)	(59)
Net amortization	21	21	6
Net periodic postretirement benefit cost	$59	$64	$47

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)		
2017	$145	$ (10)	$135
2018	150	(11)	139
2019	155	(12)	143
2020	159	(13)	146
2021	162	(14)	148
2022 to 2026	823	(73)	750

Benefit Plan Assets

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policies for both the pension plans and the other postretirement benefit plans cover a diversified mix of assets as described below. Derivative instruments may be used to gain efficient exposure to the various asset classes and as hedging tools. Additionally, the Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

The investment strategy for plan assets related to the Company's qualified pension plans 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 plans 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 Southern Company plan 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.

NOTES (continued)
Southern Company and Subsidiary Companies 2016 Annual Report

Investment Strategies and Benefit Plan Asset Fair Values
A description of the major asset classes that the pension and other postretirement benefit plans are comprised of, along with the valuation methods used for fair value measurement, is provided below:

Description	Valuation Methodology
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.	Domestic and International equities such as common stocks, American depositary receipts, and real estate investment trusts that trade on public exchanges are classified as Level 1 investments and are valued at the closing price in the active market. Equity funds with unpublished prices are valued as Level 2 when the underlying holdings are comprised of Level 1 or Level 2 equity securities.
Fixed income: A mix of domestic and international bonds.	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.
Trust-owned life insurance (TOLI): Investments of the Company's taxable trusts aimed at minimizing the impact of taxes on the portfolio.	Investments in TOLI policies are classified as Level 2 investments and are valued based on the underlying investments held in the policy's separate accounts. The underlying assets are equity and fixed income pooled funds that are comprised of Level 1 and Level 2 securities.
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 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	Investments in real estate, private equity, and special situations are generally classified as Net Asset Value as a Practical Expedient, since the underlying assets typically do not have publicly available observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. Techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, discounted cash flow analysis, prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals. The fair value of partnerships is determined by aggregating the value of the underlying assets less liabilities.

debt.

NOTES (continued)
Southern Company and Subsidiary Companies 2016 Annual Report

The fair values, and actual allocations relative to the target allocations, of Southern Company's pension plan (excluding Southern Company Gas) as of December 31, 2016 and 2015 are presented below. 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.
These fair values exclude cash, receivables related to investment income and pending investment sales, and payables related to pending investment purchases.

	Fair Value Measurements Using						
As of December 31, 2016:	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	Target Allocation	Actual Allocation
	(in millions)						
Assets:							
Domestic equity(*)	$2,010	$ 927	$ —	$ —	$2,937	26 %	29 %
International equity(*)	1,231	1,110	—	—	2,341	25	22
Fixed income:						23	29
U.S. Treasury, government, and agency bonds	—	588	—	—	588		
Mortgage- and asset-backed securities	—	13	—	—	13		
Corporate bonds	—	991	—	—	991		
Pooled funds	—	524	—	—	524		
Cash equivalents and other	996	2	—	—	998		
Real estate investments	310	—	—	1,152	1,462	14	13
Special situations	—	—		180	180	3	2
Private equity	—	—	—	549	549	9	5
Total	$4,547	$ 4,155	$ —	$ 1,881	$10,583	100 %	100 %

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

NOTES (continued)
Southern Company and Subsidiary Companies 2016 Annual Report

	Fair Value Measurements Using						
	Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs	Net Asset Value as a Practical Expedient		Target Allocation	Actual Allocation
As of December 31, 2015:	(Level 1)	(Level 2)	(Level 3)	(NAV)	Total		
	(in millions)						
Assets:							
Domestic equity[(a)]	$1,632	$ 681	$ —	$ —	$2,313	26 %	30 %
International equity[(a)]	1,190	962	—	—	2,152	25	23
Fixed income:						23	23
U.S. Treasury, government, and agency bonds	—	454	—	—	454		
Mortgage- and asset-backed securities	—	199	—	—	199		
Corporate bonds	—	1,140	—	—	1,140		
Pooled funds	—	500	—	—	500		
Cash equivalents and other	—	145	—	—	145		
Real estate investments	299	—	—	1,185	1,484	14	16
Special situations[(b)]	—	—	—	160	160	3	2
Private equity	—	—	—	536	536	9	6
Total	$3,121	$ 4,081	$ —	$ 1,881	$9,083	100 %	100 %
Liabilities:							
Derivatives	$(1)	$ —	$ —	$ —	$(1)		
Total	$3,120	$ 4,081	$ —	$ 1,881	$9,082	100 %	100 %

(a) 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.

(b) The 2015 presentation above has been revised to separately reflect special situations, consistent with the 2016 presentation.

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NOTES (continued)
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The fair values of Southern Company Gas' pension plan assets for the period ended December 31, 2016 are presented below. The fair value measurements exclude cash, receivables related to investment income, pending investment sales, and payables related to pending investment purchases. For 2016, special situations (absolute return and hedge funds) investment assets are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using				
	Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs	Net Asset Value as a Practical Expedient	
As of December 31, 2016:	(Level 1)	(Level 2)	(Level 3)	(NAV)	Total
	(in millions)				
Assets:					
Domestic equity(*)	$142	$ 343	$ —	$ —	$485
International equity(*)	—	185	—	—	185
Fixed income:					
U.S. Treasury, government, and agency bonds	—	85	—	—	85
Corporate bonds	—	41	—	—	41
Pooled funds	—	66	—	—	66
Cash equivalents and other	12	5	—	83	100
Real estate investments	4	—	—	15	19
Private equity	—	—	—	2	2
Total	$158	$ 725	$ —	$ 100	$983

(*) 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 assets of Southern Company Gas' pension plan were allocated 69% equity, 20% fixed income, 1% cash, and 10% other at December 31, 2016, compared to the asset class targets of 53% equity, 15% fixed income, 2% cash, and 30% other. Southern Company Gas' pension plan investment policy provides for variation around the target asset allocation in the form of ranges.

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The fair values of Southern Company's (excluding Southern Company Gas) other postretirement benefit plan assets as of December 31, 2016 and 2015 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investment sales, and payables related to pending investment purchases.

	Fair Value Measurements Using						
	Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs	Net Asset Value as a Practical Expedient	Total	Target Allocation	Actual Allocation
As of December 31, 2016:	(Level 1)	(Level 2)	(Level 3)	(NAV)			
	(in millions)						
Assets:							
Domestic equity(*)	$118	$ 28	$ —	$ —	$146	39 %	40 %
International equity(*)	37	61	—	—	98	23	21
Fixed income:						29	31
U.S. Treasury, government, and agency bonds	—	24	—	—	24		
Corporate bonds	—	30	—	—	30		
Pooled funds	—	49	—	—	49		
Cash equivalents and other	41	—	—	—	41		
Trust-owned life insurance	—	382	—	—	382		
Real estate investments	11	—	—	35	46	5	5
Special situations	—	—	—	5	5	1	1
Private equity	—	—	—	17	17	3	2
Total	$207	$ 574	$ —	$ 57	$838	100 %	100 %

(*) 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.

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NOTES (continued)
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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	Target Allocation	Actual Allocation
	(in millions)						
Assets:							
Domestic equity[(a)]	$106	$ 52	$ —	$ —	$158	42 %	38 %
International equity[(a)]	40	63	—	—	103	21	23
Fixed income:						28	30
U.S. Treasury, government, and agency bonds	—	22	—	—	22		
Mortgage- and asset-backed securities	—	7	—	—	7		
Corporate bonds	—	38	—	—	38		
Pooled funds	—	42	—	—	42		
Cash equivalents and other	11	9	—	—	20		
Trust-owned life insurance	—	370	—	—	370		
Real estate investments	11	—	—	40	51	5	6
Special situations[(b)]	—	—	—	5	5	1	1
Private equity	—	—	—	18	18	3	2
Total	$168	$ 603	$ —	$ 63	$834	100 %	100 %

(a) 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.

(b) The 2015 presentation above has been revised to separately reflect special situations, consistent with the 2016 presentation.

The fair values of Southern Company Gas' other postretirement benefit plan assets for the period ended December 31, 2016 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investment sales, and payables related to pending investment purchases. For 2016, special situations (absolute return and hedge funds) investment assets are presented in the tables below based on the nature of the investment.

As of December 31, 2016:	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[(*)]	$3	$ 58	$ —	$ —	$61
International equity[(*)]	—	18	—	—	18

Fixed income:					
Pooled funds	—	23	—	—	23
Cash equivalents and other	1	—	—	2	3
Total	$4	$ 99	$ —	$ 2	$105

(*) 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 assets of Southern Company Gas' other postretirement benefit plans were allocated 74% equity, 23% fixed income, 1% cash, and 2% other at December 31, 2016, compared to the asset class targets of 72% equity, 24% fixed income, 1% cash, and 3%

other. Southern Company Gas' other postretirement plan's investment policy provides for some variation in these targets in the form of ranges around the target.

Employee Savings Plan

Southern Company and its subsidiaries also sponsor 401(k) defined contribution plans covering substantially all employees and provide matching contributions up to specified percentages of an employee's eligible pay. Total matching contributions made to the plans for 2016, 2015, and 2014 were $105 million, $92 million, and $87 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

Nicor Gas and Nicor Energy Services Company, wholly-owned subsidiaries of Southern Company Gas, and Nicor Inc. are defendants in a putative class action initially filed in 2011 in state court in Cook County, Illinois. The plaintiffs purport to represent a class of the customers who purchased the Gas Line Comfort Guard product from Nicor Energy Services Company and variously allege that the marketing, sale, and billing of the Gas Line Comfort Guard product violated the Illinois Consumer Fraud and Deceptive Business Practices Act, constituting common law fraud and resulting in unjust enrichment of these entities. The plaintiffs seek, on behalf of the classes they purport to represent, actual and punitive damages, interest, costs, attorney fees, and injunctive relief. On February 8, 2017, the judge denied the plaintiffs' motion for class certification and Southern Company Gas' motion for summary judgment. The ultimate outcome of this matter cannot be determined at this time.

On January 20, 2017, a purported securities class action complaint was filed against Southern Company and certain of its and Mississippi Power's officers in the U.S. District Court for the Northern District of Georgia, Atlanta Division, by Monroe County Employees' Retirement System on behalf of all persons who purchased shares of Southern Company's common stock between April 25, 2012 and October 29, 2013. The complaint alleges that Southern Company and certain of its and Mississippi Power's officers made materially false and misleading statements regarding the Kemper IGCC in violation of certain provisions under the Securities Exchange Act of 1934, as amended. The complaint seeks, among other things, compensatory damages and litigation costs and attorneys' fees. Southern Company believes this legal challenge has no merit; however, an adverse outcome in this proceeding could have an impact on Southern Company's results of operations, financial condition, and liquidity. Southern Company will vigorously defend itself in this matter, and the ultimate outcome of this matter cannot be determined at this time.

Southern Company and its subsidiaries are subject to certain claims and legal actions arising in the ordinary course of business. In addition, the business activities of Southern Company's subsidiaries 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 Southern Company and its subsidiaries 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 Southern Company's financial statements.

Environmental Matters

Environmental Remediation

The Southern Company system 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 Southern Company system could incur substantial costs to clean up affected sites. The traditional electric operating companies and the natural gas distribution utilities in Illinois, New Jersey, Georgia, and Florida, have each received authority from their respective state PSCs or other applicable state regulatory agencies to recover approved environmental

compliance costs through regulatory mechanisms. These regulatory mechanisms are adjusted annually or as necessary within limits approved by the state PSCs or other applicable state regulatory agencies.
Georgia Power's environmental remediation liability as of December 31, 2016 was $17 million. Georgia Power has been designated or identified as a potentially responsible party at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act, and assessment and potential cleanup of such sites is expected.

NOTES (continued)
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Gulf Power's environmental remediation liability includes estimated costs of environmental remediation projects of approximately $44 million as of December 31, 2016. These estimated costs primarily relate to site closure criteria by the Florida Department of Environmental Protection (FDEP) for potential impacts to soil and groundwater from herbicide applications at Gulf Power's substations. The schedule for completion of the remediation projects is subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through Gulf Power's environmental cost recovery clause; therefore, these liabilities have no impact on net income.

Southern Company Gas' environmental remediation liability as of December 31, 2016 was $426 million based on the estimated cost of environmental investigation and remediation associated with known current and former operating sites. These environmental remediation expenditures are recoverable from customers through rate mechanisms approved by the applicable state regulatory agencies of the natural gas distribution utilities, with the exception of one site representing $5 million of the total accrued remediation costs.

In September 2015, the EPA filed an administrative complaint and notice of opportunity for hearing against Nicor Gas. The complaint alleges violation of the regulatory requirements applicable to polychlorinated biphenyls in the Nicor Gas natural gas distribution system and the EPA seeks a total civil penalty of approximately $0.3 million. On January 26, 2017, the EPA notified Nicor Gas that it agreed to voluntarily dismiss its administrative complaint with prejudice and without payment of a civil penalty or other further obligation on the part of Nicor Gas.

The ultimate outcome of these matters cannot be determined at this time; however, the final disposition of these matters is not expected to have a material impact on Southern Company's financial statements.

Nuclear Fuel Disposal Costs

Acting through the DOE and pursuant to the Nuclear Waste Policy Act of 1982, the U.S. government entered into contracts with Alabama Power and Georgia Power that require the DOE to dispose of spent nuclear fuel and high level radioactive waste generated at Plants Hatch and Farley and Plant Vogtle Units 1 and 2 beginning no later than January 31, 1998. The DOE has yet to commence the performance of its contractual and statutory obligation to dispose of spent nuclear fuel. Consequently, Alabama Power and Georgia Power pursued and continue to pursue legal remedies against the U.S. government for its partial breach of contract.

In 2014, the Court of Federal Claims entered a judgment in favor of Georgia Power and Alabama Power in their spent nuclear fuel lawsuit seeking damages for the period from January 1, 2005 through December 31, 2010. In March 2015, Georgia Power recovered approximately $18 million, based on its ownership interests, which was credited to accounts where the original costs were charged and reduced rate base, fuel, and cost of service for the benefit of customers. Also in March 2015, Alabama Power recovered approximately $26 million, which was applied to reduce the cost of service for the benefit of customers.

In 2014, Alabama Power and Georgia Power filed additional lawsuits against the U.S. government for the costs of continuing to store spent nuclear fuel at Plants Farley and Hatch and Plant Vogtle Units 1 and 2 for the period from January 1, 2011 through December 31, 2013. The damage period was subsequently extended to December 31, 2014. Damages will continue to accumulate until the issue is resolved or storage is provided. No amounts have been recognized in the financial statements as of December 31, 2016 for any potential recoveries from the additional lawsuits. The final outcome of these matters cannot be determined at this time; however, no material impact on Southern Company's net income is expected.

On-site dry spent fuel storage facilities are operational at all three plants and can be expanded to accommodate spent fuel through the expected life of each plant.

FERC Matters

Market-Based Rate Authority

The traditional electric operating companies and Southern Power have 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 electric operating companies and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In April 2015, the FERC issued an order finding that the traditional electric operating companies' and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. The FERC directed the traditional electric operating companies and Southern Power to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to

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further address market power concerns. The traditional electric operating companies and Southern Power filed a request for rehearing in May 2015 and in June 2015 filed their response with the FERC.

On December 9, 2016, the traditional electric operating companies and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. The traditional electric operating companies and Southern Power expect to make a compliance filing within 30 days accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.

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

Southern Company Gas

At December 31, 2016, Southern Company Gas' gas midstream operations was involved in three gas pipeline construction projects with expected capital expenditures of approximately $780 million. These projects, along with Southern Company Gas' existing pipelines, are intended to provide diverse sources of natural gas supplies to customers, resolve current and long-term supply planning for new capacity, enhance system reliability, and generate economic development in the areas served. One of these projects received FERC approval in August 2016. The remaining projects are pending FERC approval, which is expected to occur in 2017. The ultimate outcome of this matter cannot be determined at this time.

Regulatory Matters

Alabama Power

Rate RSE

The Alabama PSC has adopted Rate RSE that provides for periodic annual adjustments based upon Alabama Power'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% with an adjusting point of 5.98% and eligibility for a performance-based adder of seven basis points, or 0.07%, to the WCE adjusting point if Alabama Power (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. 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 Alabama Power's actual retail return is above the allowed WCE range, the excess will be refunded to customers unless otherwise directed by the Alabama PSC; however, there is no provision for additional customer billings should the actual retail return fall below the WCE range.

On December 1, 2016, Alabama Power made its required annual Rate RSE submission to the Alabama PSC of projected data for calendar year 2017. The Rate RSE adjustment was an increase of 4.48%, or $245 million annually, effective January 1, 2017 and includes the performance based adder of 0.07%. Under the terms of Rate RSE, the maximum increase for 2018 cannot exceed 3.52%.

As of December 31, 2016, the 2016 retail return exceeded the allowed WCE range; therefore, Alabama Power established a $73 million Rate RSE refund liability. In accordance with an order issued on February 14, 2017 by the Alabama PSC, Alabama Power was directed to apply the full amount of the refund to reduce the under recovered balance of Rate CNP PPA.

Rate CNP PPA

Alabama Power'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. Alabama Power may also recover retail costs associated with certificated PPAs under Rate CNP PPA. On March 8, 2016, the Alabama PSC issued a consent order that Alabama Power leave in effect the current Rate CNP PPA factor for billings for the period April 1, 2016 through March 31,

2017. No adjustment to Rate CNP PPA is expected in 2017. As of December 31, 2016 and 2015, Alabama Power had an under recovered certificated PPA balance of $142 million and $99 million, respectively, which is included in other regulatory assets, deferred in the balance sheet.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, Alabama Power was authorized to eliminate the under recovered balance in Rate CNP PPA at December 31, 2016, which totaled approximately $142 million. As discussed herein under "Rate RSE," Alabama Power will utilize the full amount of its $73 million Rate RSE refund liability to reduce the amount of the Rate CNP PPA under recovery and will reclassify the remaining $69 million to a separate regulatory asset. The amortization of the new regulatory asset through Rate RSE will begin concurrently with the effective date of Alabama

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Power's next depreciation study, which is expected to occur within the next three to five years. Alabama Power's current depreciation study became effective January 1, 2017.
Rate CNP Compliance
Rate CNP Compliance allows for the recovery of Alabama Power's retail costs associated with laws, regulations, and other such mandates directed at the utility industry involving the environment, security, reliability, safety, sustainability, or similar considerations impacting Alabama Power's facilities or operations. 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. Revenues for Rate CNP Compliance, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will have no significant effect on revenues or net income, but will affect annual cash flow. Changes in compliance related operations and maintenance expenses and depreciation generally will have no effect on net income.
On December 6, 2016, the Alabama PSC issued a consent order that Alabama Power leave in effect for 2017 the factors associated with Alabama Power's compliance costs for the year 2016. As stated in the consent order, any under-collected amount for prior years will be deemed recovered before the recovery of any current year amounts. Any under recovered amounts associated with 2017 will be reflected in the 2018 filing.
In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, Alabama Power is authorized to classify any under recovered balance in Rate CNP Compliance up to approximately $36 million to a separate regulatory asset. The amortization of the new regulatory asset through Rate RSE will begin concurrently with the effective date of Alabama Power's next depreciation study, which is expected to occur within the next three to five years. Alabama Power's current depreciation study became effective January 1, 2017.
Rate ECR
Alabama Power has established energy cost recovery rates under Alabama Power'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. Alabama Power, 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 Southern 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 2015, the Alabama PSC issued a consent order that Alabama Power decrease the Rate ECR factor from 2.681 cents per KWH to 2.030 cents per KWH.
On December 6, 2016, the Alabama PSC approved a decrease in Alabama Power's Rate ECR factor from 2.030 to 2.015 cents per KWH, equal to 0.15%, or $8 million annually, based upon projected billings, effective January 1, 2017. The rate will return to 5.910 cents per KWH in 2018 absent a further order from the Alabama PSC.
At December 31, 2016 and 2015, Alabama Power's over recovered fuel costs totaled $76 million and $238 million, respectively, and are included in other regulatory liabilities, current. 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.
In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, Alabama Power is authorized to classify any under recovered balance in Rate ECR up to approximately $36 million to a separate regulatory asset. The amortization of the new regulatory asset through Rate RSE will begin concurrently with the effective date of Alabama Power's next depreciation study, which is expected to occur within the next three to five years. Alabama Power's current depreciation study became effective January 1, 2017.
Rate NDR

Based on an order from the Alabama PSC, Alabama Power 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 Alabama Power 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. Alabama Power 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. Alabama Power 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 Alabama Power's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear. No such accruals were recorded or designated in any period presented.

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, Alabama Power 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, Alabama Power retired Plant Gorgas Units 6 and 7 (200 MWs). Additionally, in April 2015, Alabama Power 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, Alabama Power retired Plant Barry Unit 3 (225 MWs) in August 2015 and it is no longer available for generation. In April 2016, as part of its environmental compliance strategy, Alabama Power ceased using coal at Plant Greene County Units 1 and 2 (300 MWs representing Alabama Power's ownership interest) and began operating Units 1 and 2 solely on natural gas in June 2016 and July 2016, respectively.

In accordance with this accounting order from the Alabama PSC, Alabama Power 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 units' remaining useful lives, as established prior to the decision for retirement; therefore, these decisions associated with coal operations had no significant impact on Southern Company's financial statements.

Georgia Power

Rate Plans

Pursuant to the terms and conditions of a settlement agreement related to Southern Company's acquisition of Southern Company Gas approved by the Georgia PSC on April 14, 2016, the 2013 ARP will continue in effect until December 31, 2019, and Georgia Power will be required to file its next base rate case by July 1, 2019. Furthermore, through December 31, 2019, Georgia Power and Atlanta Gas Light Company each will retain their respective merger savings, net of transition costs, as defined in the settlement agreement; through December 31, 2022, such net merger savings applicable to each will be shared on a 60/40 basis with their respective customers; thereafter, all merger savings will be retained by customers.

In accordance with the 2013 ARP, the Georgia PSC approved increases to tariffs effective January 1, 2015 and 2016 as follows: (1) traditional base tariff rates by approximately $107 million and $49 million, respectively; (2) Environmental Compliance Cost Recovery tariff by approximately $23 million and $75 million, respectively; (3) Demand-Side Management tariffs by approximately $3 million in each year; and (4) Municipal Franchise Fee tariff by approximately $3 million and $13 million, respectively, for a total increase in base revenues of approximately $136 million and $140 million, respectively.

Under the 2013 ARP, Georgia Power's retail ROE is set at 10.95% and earnings are evaluated against a retail ROE range of 10.00% to 12.00%. Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by Georgia Power. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. In 2014, Georgia Power's retail ROE exceeded 12.00%, and Georgia Power refunded to retail customers approximately $11 million in 2016, as approved by the Georgia PSC on February 18, 2016. In 2015, Georgia Power's retail ROE was within the allowed retail ROE range. In 2016, Georgia Power's retail ROE exceeded 12.00%, and Georgia Power expects to refund to retail customers approximately $40 million, subject to review and approval by the Georgia PSC. The ultimate outcome of this matter cannot be determined at this time.

Integrated Resource Plan

On July 28, 2016, the Georgia PSC approved the 2016 IRP including the decertification and retirement of Plant Mitchell Units 3, 4A, and 4B (217 MWs) and Plant Kraft Unit 1 (17 MWs), as well as the decertification of the Intercession City unit (143 MWs total capacity). On August 2, 2016, the Plant Mitchell and Plant Kraft units were retired. On August 31, 2016, Georgia Power sold its 33% ownership interest in the Intercession City unit to Duke Energy Florida, LLC.

Additionally, the Georgia PSC approved Georgia Power's environmental compliance strategy and related expenditures proposed in the 2016 IRP, including measures taken to comply with existing government-imposed environmental mandates, subject to limits on expenditures for Plant McIntosh Unit 1 and Plant Hammond Units 1 through 4.

The Georgia PSC approved the reclassification of the remaining net book value of Plant Mitchell Unit 3 and costs associated with materials and supplies remaining at the unit retirement date to a regulatory asset. Recovery of the unit's net book value will continue through December 31, 2019, as provided in the 2013 ARP. The timing of the recovery of the remaining balance of the unit's net book value as of December 31, 2019 and costs associated with materials and supplies remaining at the unit retirement date was deferred for consideration in Georgia Power's 2019 base rate case.

The Georgia PSC also approved the Renewable Energy Development Initiative to procure an additional 1,200 MWs of renewable resources primarily utilizing market-based prices established through a competitive bidding process with expected in-service dates between 2018 and 2021. Additionally, 200 MWs of self-build capacity for use by Georgia Power was approved, as well as consideration for no more than 200 MWs of capacity as part of a renewable commercial and industrial program.

The Georgia PSC also approved recovery of costs up to $99 million through June 30, 2019 to preserve nuclear as an option at a future generation site in Stewart County, Georgia. The timing of cost recovery will be determined by the Georgia PSC in a future base rate case. The ultimate outcome of this matter cannot be determined at this time.

Fuel Cost Recovery

Georgia Power has established fuel cost recovery rates approved by the Georgia PSC. In December 2015, the Georgia PSC approved Georgia Power's request to lower annual billings by approximately $350 million effective January 1, 2016. On May 17, 2016, the Georgia PSC approved Georgia Power's request to further lower annual billings by approximately $313 million effective June 1, 2016. On December 6, 2016, the Georgia PSC approved the delay of Georgia Power's next fuel case, which was previously scheduled to be filed by February 28, 2017. The Georgia PSC will review Georgia Power's cumulative over or under recovered fuel balance no later than September 1, 2018 and evaluate the need to file a fuel case unless Georgia Power deems it necessary to file a fuel case at an earlier time. Under an Interim Fuel Rider, Georgia Power continues to be allowed to adjust its fuel cost recovery rates prior to the next fuel case if the under recovered fuel balance exceeds $200 million.

Georgia Power's fuel cost recovery mechanism includes costs associated with a natural gas hedging program, as revised and approved by the Georgia PSC, allowing the use of an array of derivative instruments within a 48-month time horizon effective January 1, 2016.

Georgia Power's over recovered fuel balance totaled approximately $84 million at December 31, 2016 and is included in over recovered regulatory clause revenues, current. At December 31, 2015, Georgia Power's over recovered fuel balance totaled approximately $116 million, including $10 million in over recovered regulatory clause revenues, current and $106 million in other deferred credits and liabilities.

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

Storm Damage Recovery

As of December 31, 2016, the balance in Georgia Power's regulatory asset related to storm damage was $206 million. During October 2016, Hurricane Matthew caused significant damage to Georgia Power's transmission and distribution facilities. As of December 31, 2016, Georgia Power had recorded incremental restoration cost related to this hurricane of $121 million, of which approximately $116 million was charged to the storm damage reserve and the remainder was capitalized. Georgia Power is accruing $30 million annually through December 31, 2019, as provided in the 2013 ARP, to the storm damage reserve to cover the operations and maintenance costs of damages from major storms to its transmission and distribution facilities, which is recoverable through base rates. The rate of recovery of storm damage costs after December 31, 2019 is expected to be adjusted in

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Georgia Power's 2019 base rate case. As a result of this regulatory treatment, costs related to storms are not expected to have a material impact on Southern Company's financial statements.

Nuclear Construction

In 2008, Georgia Power, acting for itself and as agent for Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia (Dalton), acting by and through its Board of Water, Light, and Sinking Fund Commissioners, doing business as Dalton Utilities (collectively, Vogtle Owners), entered into an agreement with a consortium consisting of Westinghouse and Stone & Webster, Inc., which was subsequently acquired by Westinghouse and changed its name to WECTEC Global Project Services Inc. (WECTEC) (Westinghouse and WECTEC, collectively, Contractor), pursuant to which the Contractor agreed to design, engineer, procure, construct, and test two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities at Plant Vogtle (Vogtle 3 and 4 Agreement).

Under the terms of the Vogtle 3 and 4 Agreement, the Vogtle Owners agreed to pay a purchase price subject to certain price escalations and adjustments, including fixed escalation amounts and index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. The Vogtle 3 and 4 Agreement also provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees, subject to an aggregate cap of 10% of the contract price, or approximately $920 million to $930 million. In addition, the Vogtle 3 and 4 Agreement provides for limited cost sharing by the Vogtle Owners for Contractor costs under certain conditions (which Georgia Power has not been notified have occurred) with maximum additional capital costs under this provision attributable to Georgia Power (based on Georgia Power's ownership interest) of approximately $114 million. Each Vogtle Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Contractor under the Vogtle 3 and 4 Agreement. Georgia Power's proportionate share is 45.7%. In the event of certain credit rating downgrades of any Vogtle Owner, such Vogtle Owner will be required to provide a letter of credit or other credit enhancement.

Certain obligations of Westinghouse have been guaranteed by Toshiba Corporation (Toshiba), Westinghouse's parent company. In the event of certain credit rating downgrades of Toshiba, Westinghouse is required to provide letters of credit or other credit enhancement. In December 2015, Toshiba experienced credit rating downgrades and Westinghouse provided the Vogtle Owners with $920 million of letters of credit. These letters of credit remain in place in accordance with the terms of the Vogtle 3 and 4 Agreement.

On February 14, 2017, Toshiba announced preliminary earnings results for the period ended December 31, 2016, which included a substantial goodwill impairment charge at Westinghouse attributed to increased cost estimates to complete its U.S. nuclear projects, including Plant Vogtle Units 3 and 4. Toshiba also warned that it will likely be in a negative equity position as a result of the charges. At the same time, Toshiba reaffirmed its commitment to its U.S. nuclear projects with implementation of management changes and increased oversight. An inability or failure by the Contractor to perform its obligations under the Vogtle 3 and 4 Agreement could have a material impact on the construction of Plant Vogtle Units 3 and 4.

Under the terms of the Vogtle 3 and 4 Agreement, the Contractor does not have a right to terminate the Vogtle 3 and 4 Agreement for convenience. The Contractor may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including certain Vogtle Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Vogtle Owners, Vogtle Owner insolvency, and certain other events. In the event of an abandonment of work by the Contractor, the maximum liability of the Contractor under the Vogtle 3 and 4 Agreement is increased significantly, but remains subject to limitations. The Vogtle Owners may terminate the Vogtle 3 and 4 Agreement at any time for convenience, provided that the Vogtle Owners will be required to pay certain termination costs.

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4 with a certified capital cost of $4.418 billion. In addition, in 2009 the Georgia PSC approved inclusion of the Plant Vogtle Units 3 and 4 related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows Georgia Power to recover financing costs for nuclear construction projects certified by the Georgia PSC. Financing costs are recovered on all applicable certified costs through annual adjustments to the NCCR tariff by including the related CWIP accounts in rate base during the construction period. The Georgia PSC approved an NCCR tariff of $368 million for 2014, as well as increases to the NCCR tariff of approximately $27 million and $19 million effective January 1, 2015 and 2016, respectively.

Georgia Power is required to file semi-annual Vogtle Construction Monitoring (VCM) reports with the Georgia PSC by February 28 and August 31 each year. In accordance with the 2009 certification order, Georgia Power requested amendments to the Plant Vogtle Units 3 and 4 certificate in both the February 2013 (eighth VCM) and February 2015 (twelfth VCM) filings, when projected construction capital costs to be borne by Georgia Power increased by 5% above the certified costs and estimated in-service dates were extended. In October 2013, the Georgia PSC approved a stipulation (2013 Stipulation) between Georgia Power and the Georgia PSC Staff to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate until the completion of

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Plant Vogtle Unit 3 or earlier if deemed appropriate by the Georgia PSC and Georgia Power. In April 2015, the Georgia PSC recognized that the certified cost and the 2013 Stipulation did not constitute a cost recovery cap and deemed the amendment requested in the February 2015 filing unnecessary and withdrawn until the completion of construction of Plant Vogtle Unit 3 consistent with the 2013 Stipulation.

On December 31, 2015, Westinghouse and the Vogtle Owners entered into a definitive settlement agreement (Contractor Settlement Agreement) to resolve disputes between the Vogtle Owners and the Contractor under the Vogtle 3 and 4 Agreement, including litigation that was pending in the U.S. District Court for the Southern District of Georgia (Vogtle Construction Litigation). Effective December 31, 2015, Georgia Power, acting for itself and as agent for the other Vogtle Owners, and the Contractor entered into an amendment to the Vogtle 3 and 4 Agreement to implement the Contractor Settlement Agreement. The Contractor Settlement Agreement and the related amendment to the Vogtle 3 and 4 Agreement (i) restrict the Contractor's ability to seek further increases in the contract price by clarifying and limiting the circumstances that constitute nuclear regulatory changes in law; (ii) provide for enhanced dispute resolution procedures; (iii) revise the guaranteed substantial completion dates to June 30, 2019 for Unit 3 and June 30, 2020 for Unit 4; (iv) provide that delay liquidated damages will commence if the nuclear fuel loading date for each unit does not occur by December 31, 2018 for Unit 3 and December 31, 2019 for Unit 4; and (v) provide that Georgia Power, based on its ownership interest, will pay to the Contractor and capitalize to the project cost approximately $350 million, of which approximately $263 million had been paid as of December 31, 2016. In addition, the Contractor Settlement Agreement provides for the resolution of other open existing items relating to the scope of the project under the Vogtle 3 and 4 Agreement, including cyber security, for which costs are reflected in Georgia Power's current in-service forecast of $5.440 billion. Further, as part of the settlement and Westinghouse's acquisition of WECTEC: (i) Westinghouse engaged Fluor Enterprises, Inc., a subsidiary of Fluor Corporation, as a new construction subcontractor and (ii) the Vogtle Owners, Chicago Bridge & Iron Co, N.V., and The Shaw Group Inc. entered into mutual releases of any and all claims arising out of events or circumstances in connection with the construction of Plant Vogtle Units 3 and 4 that occurred on or before the date of the Contractor Settlement Agreement. On January 5, 2016, the Vogtle Construction Litigation was dismissed with prejudice.

On December 20, 2016, the Georgia PSC voted to approve a settlement agreement (Vogtle Cost Settlement Agreement) resolving the following prudence matters: (i) none of the $3.3 billion of costs incurred through December 31, 2015 and reflected in the fourteenth VCM report will be disallowed from rate base on the basis of imprudence; (ii) the Contractor Settlement Agreement is reasonable and prudent and none of the amounts paid or to be paid pursuant to the Contractor Settlement Agreement should be disallowed from rate base on the basis of imprudence; (iii) financing costs on verified and approved capital costs will be deemed prudent provided they are incurred prior to December 31, 2019 and December 31, 2020 for Plant Vogtle Units 3 and 4, respectively; and (iv) (a) the in-service capital cost forecast will be adjusted to $5.680 billion (Revised Forecast), which includes a contingency of $240 million above Georgia Power's current forecast of $5.440 billion, (b) capital costs incurred up to the Revised Forecast will be presumed to be reasonable and prudent with the burden of proof on any party challenging such costs, and (c) Georgia Power would have the burden to show that any capital costs above the Revised Forecast are reasonable and prudent. Under the terms of the Vogtle Cost Settlement Agreement, the certified in-service capital cost for purposes of calculating the NCCR tariff will remain at $4.418 billion. Construction capital costs above $4.418 billion will accrue AFUDC through the date each unit is placed in service. The ROE used to calculate the NCCR tariff was reduced from 10.95% (the ROE rate setting point authorized by the Georgia PSC in the 2013 ARP) to 10.00% effective January 1, 2016. For purposes of the AFUDC calculation, the ROE on costs between $4.418 billion and $5.440 billion will also be 10.00% and the ROE on any amounts above $5.440 billion would be Georgia Power's average cost of long-term debt. If the Georgia PSC adjusts Georgia Power's ROE rate setting point in a rate case prior to Plant Vogtle Units 3 and 4 being placed into retail rate base, then the ROE for purposes of calculating both the NCCR tariff and AFUDC will likewise be 95 basis points lower than the revised ROE rate setting point. If Plant Vogtle Units 3 and 4 are not placed in service by December 31, 2020, then (i) the ROE for purposes of calculating the NCCR tariff will be reduced an additional 300 basis points, or $8 million per month, and may, at the Georgia PSC's discretion, be accrued to be used for the benefit of customers, until such time as the units are placed in service and (ii) the ROE used to calculate AFUDC will be Georgia Power's average cost of long-term debt.

Under the terms of the Vogtle Cost Settlement Agreement, Plant Vogtle Units 3 and 4 will be placed into retail rate base on December 31, 2020 or when placed in service, whichever is later. The Georgia PSC will determine for retail ratemaking purposes the process of transitioning Plant Vogtle Units 3 and 4 from a construction project to an operating plant no later than Georgia Power's base rate case required to be filed by July 1, 2019.

The Georgia PSC has approved fifteen VCM reports covering the periods through June 30, 2016, including construction capital costs incurred, which through that date totaled $3.7 billion. Georgia Power expects to file the sixteenth VCM report, covering the period from July 1 through December 31, 2016, requesting approval of $222 million of construction capital costs incurred during that period, with the Georgia PSC by February 28, 2017. Georgia Power's CWIP balance for Plant Vogtle Units 3 and 4 was

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approximately $3.9 billion as of December 31, 2016, and Georgia Power had incurred $1.3 billion in financing costs through December 31, 2016.

As of December 31, 2016, Georgia Power had borrowed $2.6 billion related to Plant Vogtle Units 3 and 4 costs through a loan guarantee agreement between Georgia Power and the DOE and a multi-advance credit facility among Georgia Power, the DOE, and the FFB. See Note 6 under "DOE Loan Guarantee Borrowings" for additional information, including applicable covenants, events of default, and mandatory prepayment events.

There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4 at the federal and state level and additional challenges may arise as construction proceeds. Processes are in place that are designed to assure compliance with the requirements specified in the Westinghouse Design Control Document and the combined construction and operating licenses, including inspections by Southern Nuclear and the NRC that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the NRC. Various design and other licensing-based compliance matters, including the timely resolution of Inspections, Tests, Analyses, and Acceptance Criteria and the related approvals by the NRC, may arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs either to the Vogtle Owners or the Contractor or to both.

In addition to Toshiba's reaffirmation of its commitment, the Contractor provided Georgia Power with revised forecasted in-service dates of December 2019 and September 2020 for Plant Vogtle Units 3 and 4, respectively. Georgia Power is currently reviewing a preliminary summary schedule supporting these dates that ultimately must be reconciled to a detailed integrated project schedule. As construction continues, the risk remains that challenges with Contractor performance including labor productivity, fabrication, delivery, assembly, and installation of plant systems, structures, and components, or other issues could arise and may further impact project schedule and cost. Georgia Power expects the Contractor to employ mitigation efforts and believes the Contractor is responsible for any related costs under the Vogtle 3 and 4 Agreement. Georgia Power estimates its financing costs for Plant Vogtle Units 3 and 4 to be approximately $30 million per month, with total construction period financing costs of approximately $2.5 billion. Additionally, Georgia Power estimates its owner's costs to be approximately $6 million per month, net of delay liquidated damages.

The revised forecasted in-service dates are within the timeframe contemplated in the Vogtle Cost Settlement Agreement and would enable both units to qualify for production tax credits the IRS has allocated to each of Plant Vogtle Units 3 and 4, which require the applicable unit to be placed in service before 2021. The net present value of the production tax credits is estimated at approximately $400 million per unit.

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

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

Gulf Power

Retail Base Rate Cases

In 2013, the Florida PSC approved a settlement agreement among Gulf Power and all of the intervenors to Gulf Power's retail base rate case (Gulf Power 2013 Rate Case Settlement Agreement). Under the terms of the Gulf Power 2013 Rate Case Settlement Agreement, Gulf Power (1) increased base rates approximately $35 million and $20 million annually effective January 2014 and 2015, respectively; (2) continued its authorized retail ROE midpoint (10.25%) and range (9.25% – 11.25%); and (3) accrued a return similar to AFUDC on certain transmission system upgrades placed into service after January 2014 through January 1, 2017.

The Gulf Power 2013 Rate Case Settlement Agreement also provides that Gulf Power may reduce depreciation and record a regulatory asset that will be included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million from January 2014 through June 2017. In any given month, such depreciation reduction may not exceed the amount necessary for the retail ROE, as reported to the Florida PSC monthly, to reach the midpoint of the authorized retail ROE range then in effect. Recovery of the regulatory asset will occur over a period to be determined by the Florida PSC in the Gulf Power 2016 Rate Case, as defined below. For 2014 and 2015, Gulf Power recognized reductions in depreciation expense of $8.4 million and $20.1 million, respectively. No net reduction in depreciation was recorded by Gulf Power in 2016.

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On October 12, 2016, Gulf Power filed a petition (Gulf Power 2016 Rate Case) with the Florida PSC requesting an annual increase in retail rates and charges of $106.8 million based on the projected test year of January 1, 2017 through December 31, 2017 and a retail ROE of 11% compared to the current retail ROE of 10.25%. The requested increase includes recovery of the portion of Plant Scherer Unit 3 that has been rededicated to serving retail customers following the contract expirations at the end of 2015 and May 2016. If retail recovery of Plant Scherer Unit 3 is not approved by the Florida PSC in the 2016 Rate Case, Gulf Power may consider an asset sale. The current book value of Gulf Power's ownership of Plant Scherer Unit 3 could exceed market value which could result in a material loss. The Florida PSC is expected to make a decision on the Gulf Power 2016 Rate Case in the second quarter 2017. Gulf Power has requested that the increase in base rates, if approved by the Florida PSC, become effective in July 2017. The ultimate outcome of this matter cannot be determined at this time.

Southern Company Gas

Natural Gas Cost Recovery

Southern Company Gas has established natural gas cost recovery rates that are approved by the applicable state regulatory agencies in the states in which it serves. Natural gas cost recovery revenues are adjusted for differences in actual recoverable natural gas costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on Southern Company's revenues or net income, but will affect cash flow.

Regulatory Infrastructure Programs

Six of Southern Company Gas' seven natural gas distribution utilities are involved in ongoing capital projects associated with infrastructure improvement programs that have been previously approved by their applicable state regulatory agencies and provide an appropriate return on invested capital. These infrastructure improvement programs are designed to update or expand the natural gas distribution systems of the natural gas distribution utilities to improve reliability and meet operational flexibility and growth. Initial program lengths range from four to 10 years, with the longest set to expire in 2025.

On February 21, 2017, the Georgia PSC approved a rate adjustment mechanism for Atlanta Gas Light that included the 2017 capital investment associated with a four-year extension of one of its existing infrastructure programs, with a total additional investment of $177 million through 2020. In addition, Elizabethtown Gas currently has a proposed infrastructure improvement program pending approval by the New Jersey Board of Public Utilities requesting to invest more than $1.1 billion through 2027.

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

Integrated Coal Gasification Combined Cycle

Kemper IGCC Overview

The Kemper IGCC utilizes IGCC technology with an expected output capacity of 582 MWs. The Kemper IGCC is fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by Mississippi Power and situated adjacent to the Kemper IGCC. The mine, operated by North American Coal Corporation, started commercial operation in 2013. In connection with the Kemper IGCC, Mississippi Power constructed and plans to operate approximately 61 miles of CO_2 pipeline infrastructure for the transport of captured CO_2 for use in enhanced oil recovery.

Kemper IGCC Schedule and Cost Estimate

In 2012, the Mississippi PSC issued the 2012 MPSC CPCN Order, a detailed order confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing the acquisition, construction, and operation of the Kemper IGCC. The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC CPCN Order was $2.4 billion, net of $245 million of grants awarded to the Kemper IGCC project by the DOE under the Clean Coal Power Initiative Round 2 (Initial DOE Grants) and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and AFUDC related to the Kemper IGCC. The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion, with recovery of prudently-incurred costs subject to approval by the Mississippi PSC. The Kemper IGCC was originally projected to be placed in service in May 2014. Mississippi Power placed the combined cycle and the associated common facilities portion of the Kemper IGCC in service in August 2014. The remainder of the plant, including the gasifiers and the gas clean-up facilities, represents first-of-a-kind technology. The initial production of syngas began on July 14, 2016 for gasifier "B" and on September 13, 2016 for gasifier "A." Mississippi Power achieved integrated operation of both gasifiers on January 29, 2017, including the production of electricity from syngas in both combustion turbines. Mississippi Power subsequently completed a brief outage to repair and make modifications to further improve the plant's ability to achieve sustained operations sufficient to support placing the plant in service for customers. Efforts to reach sustained operation of both gasifiers and production of electricity from syngas in both combustion turbines are in process. The plant has produced and captured CO_2, and has produced sulfuric acid and ammonia, all of acceptable quality under

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the related off-take agreements. On February 20, 2017, Mississippi Power determined gasifier "B," which has been producing syngas over 60% of the time since early November 2016, requires an outage to remove ash deposits from its ash removal system. Gasifier "A" and combustion turbine "A" are expected to remain in operation, producing electricity from syngas, as well as producing chemical by-products. As a result, Mississippi Power currently expects the remainder of the Kemper IGCC, including both gasifiers, will be placed in service by mid-March 2017.
Mississippi Power's Kemper IGCC 2010 project estimate, current cost estimate (which includes the impacts of the Mississippi Supreme Court's (Court) decision discussed herein under "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order"), and actual costs incurred as of December 31, 2016, all of which include 100% of the costs for the Kemper IGCC, are as follows:

Cost Category	2010 Project Estimate[a]	Current Cost Estimate[b]	Actual Costs
	(in billions)		
Plant Subject to Cost Cap[c][e]	$2.40	$ 5.64	$5.44
Lignite Mine and Equipment	0.21	0.23	0.23
CO_2 Pipeline Facilities	0.14	0.11	0.11
AFUDC[d]	0.17	0.79	0.75
Combined Cycle and Related Assets Placed in Service – Incremental[e]	—	0.04	0.04
General Exceptions	0.05	0.10	0.09
Deferred Costs[e]	—	0.22	0.21
Additional DOE Grants[f]	—	(0.14)	(0.14)
Total Kemper IGCC[g]	$2.97	$ 6.99	$6.73

(a) The 2010 Project Estimate is the certificated cost estimate adjusted to include the certificated estimate for the CO_2 pipeline facilities approved in 2011 by the Mississippi PSC, as well as the lignite mine and equipment, AFUDC, and general exceptions.

(b) Amounts in the Current Cost Estimate include certain estimated post-in-service costs which are expected to be subject to the cost cap.

(c) The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion, net of the Initial DOE Grants and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, AFUDC, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when Mississippi Power demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on customers relative to the original proposal for the CPCN) (Cost Cap Exceptions). The Current Cost Estimate and the Actual Costs include non-incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service in August 2014 that are subject to the $2.88 billion cost cap and exclude post-in-service costs for the lignite mine. See "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" herein for additional information.

(d) Mississippi Power's 2010 Project Estimate included recovery of financing costs during construction rather than the accrual of AFUDC. This approach was not approved by the Mississippi PSC as described in "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order." The Current Cost Estimate also reflects the impact of a settlement agreement with the wholesale customers for cost-based rates under FERC's jurisdiction.

(e) Non-capital Kemper IGCC-related costs incurred during construction were initially deferred as regulatory assets. Some of these costs are now included in rates and are being recognized through income; however, such costs continue to be included in the Current Cost Estimate and the Actual Costs at December 31, 2016. The wholesale portion of debt carrying costs, whether deferred or recognized through income, is not included in the Current Cost Estimate and the Actual Costs at December 31, 2016. See "Rate Recovery of Kemper IGCC Costs – Regulatory

Assets and Liabilities" herein for additional information.

(f) On April 8, 2016, Mississippi Power received approximately $137 million in additional grants from the DOE for the Kemper IGCC (Additional DOE Grants), which are expected to be used to reduce future rate impacts for customers.

(g) The Current Cost Estimate and the Actual Costs include $2.76 billion that will not be recovered for costs above the cost cap, $0.83 billion of investment costs included in current rates for the combined cycle and related assets in service, and $0.08 billion of costs that were previously expensed for the combined cycle and related assets in service. The Current Cost Estimate and the Actual Costs exclude $0.25 billion of costs not included in current rates for post-June 2013 mine operations, the lignite fuel inventory, and the nitrogen plant capital lease, which will be included in the 2017 Rate Case to be filed by June 3, 2017. See Note 6 under "Capital Leases" and "Rate Recovery of Kemper IGCC Costs – 2017 Rate Case" herein for additional information.

Of the total costs, including post-in-service costs for the lignite mine, incurred as of December 31, 2016, $3.67 billion was included in property, plant, and equipment (which is net of the Initial DOE Grants, the Additional DOE Grants, and estimated probable losses of $2.84 billion), $6 million in other property and investments, $75 million in fossil fuel stock, $47 million in materials and supplies, $29 million in other regulatory assets, current, $172 million in other regulatory assets, deferred, $3 million in other current assets, and $14 million in other deferred charges and assets in the balance sheet.

Mississippi Power does not intend to seek rate recovery for any costs related to the construction of the Kemper IGCC that exceed the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions. Southern Company recorded pre-tax charges to income for revisions to the cost estimate of $348 million ($215 million after tax), $365 million ($226 million after tax), and $868 million ($536 million after tax) in 2016, 2015, and 2014, respectively. Since 2013, in the aggregate, Southern Company has incurred charges of $2.76 billion ($1.71 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through December 31, 2016. The increases to the cost estimate in 2016 primarily reflect $186 million for the extension of the Kemper IGCC's projected in-service date from August 31, 2016 to March 15, 2017 and $162 million for increased efforts related to operational readiness and challenges in start-up and commissioning activities, including the cost of repairs and modifications to both gasifiers, mechanical improvements to coal feed and ash management systems, and outage work, as well as certain post-in-service costs expected to be subject to the cost cap.

In addition to the current construction cost estimate, Mississippi Power is identifying potential improvement projects that ultimately may be completed subsequent to placing the remainder of the Kemper IGCC in service. If completed, such improvement projects would be expected to enhance plant performance, safety, and/or operations. As of December 31, 2016, approximately $12 million of related potential costs has been included in the estimated loss on the Kemper IGCC. Other projects have yet to be fully evaluated, have not been included in the current cost estimate, and may be subject to the $2.88 billion cost cap.

Any extension of the in-service date beyond mid-March 2017 is currently estimated to result in additional base costs of approximately $25 million to $35 million per month, which includes maintaining necessary levels of start-up labor, materials, and fuel, as well as operational resources required to execute start-up and commissioning activities. Additional costs may be required for remediation of any further equipment and/or design issues identified. Any extension of the in-service date with respect to the Kemper IGCC beyond mid-March 2017 would also increase costs for the Cost Cap Exceptions, which are not subject to the $2.88 billion cost cap established by the Mississippi PSC. These costs include AFUDC, which is currently estimated to total approximately $16 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting and legal fees of approximately $3 million per month. For additional information, see "2015 Rate Case" herein.

Further cost increases and/or extensions of the expected in-service date may result from factors including, but not limited to, difficulties integrating the systems required for sustained operations, sustaining nitrogen supply, major equipment failure, unforeseen engineering or design problems including any repairs and/or modifications to systems, and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC). Any further changes in the estimated costs of the Kemper IGCC subject to the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions, will be reflected in Southern Company's statements of income and these changes could be material.

Rate Recovery of Kemper IGCC Costs

Given the variety of potential scenarios and the uncertainty of the outcome of future regulatory proceedings with the Mississippi PSC (and any subsequent related legal challenges), the ultimate outcome of the rate recovery matters discussed herein, including the resolution of legal challenges, cannot now be determined but could result in further material charges that could have a material impact on Southern Company's results of operations, financial condition, and liquidity.

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As of December 31, 2016, in addition to the $2.76 billion of costs above the Mississippi PSC's $2.88 billion cost cap that have been recognized as a charge to income, Mississippi Power had incurred approximately $1.99 billion in costs subject to the cost cap and approximately $1.46 billion in Cost Cap Exceptions related to the construction and start-up of the Kemper IGCC that are not included in current rates. These costs primarily relate to the following:

Cost Category	Actual Costs (in billions)
Gasifiers and Gas Clean-up Facilities	$ 1.88
Lignite Mine Facility	0.31
CO_2 Pipeline Facilities	0.11
Combined Cycle and Common Facilities	0.16
AFUDC	0.69
General exceptions	0.07
Plant inventory	0.03
Lignite inventory	0.08
Regulatory and other deferred assets	0.12
Subtotal	3.45
Additional DOE Grants	(0.14)
Total	$ 3.31

Of these amounts, approximately 29% is related to wholesale and approximately 71% is related to retail, including the 15% portion that was previously contracted to be sold to SMEPA. Mississippi Power and its wholesale customers have generally agreed to the similar regulatory treatment for wholesale tariff purposes as approved by the Mississippi PSC for retail for Kemper IGCC-related costs. See "Termination of Proposed Sale of Undivided Interest" herein for further information.

Prudence

On August 17, 2016, the Mississippi PSC issued an order establishing a discovery docket to manage all filings related to the prudence of the Kemper IGCC. On October 3, 2016, Mississippi Power made a required compliance filing, which included a review and explanation of differences between the Kemper IGCC project estimate set forth in the 2010 CPCN proceedings and the most recent Kemper IGCC project estimate, as well as comparisons of current cost estimates and current expected plant operational parameters to the estimates presented in the 2010 CPCN proceedings for the first five years after the Kemper IGCC is placed in service. Compared to amounts presented in the 2010 CPCN proceedings, operations and maintenance expenses have increased an average of $105 million annually and maintenance capital has increased an average of $44 million annually for the first full five years of operations for the Kemper IGCC. Additionally, while the current estimated operational availability estimates reflect ultimate results similar to those presented in the 2010 CPCN proceedings, the ramp up period for the current estimates reflects a lower starting point and a slower escalation rate. On November 17, 2016, Mississippi Power submitted a supplemental filing to the October 3, 2016 compliance filing to present revised non-fuel operations and maintenance expense projections for the first year after the Kemper IGCC is placed in service. This supplemental filing included approximately $68 million in additional estimated operations and maintenance costs expected to be required to support the operations of the Kemper IGCC during that period. Mississippi Power will not seek recovery of the $68 million in additional estimated costs from customers if incurred.

Mississippi Power expects the Mississippi PSC to address these matters in connection with the 2017 Rate Case.

Economic Viability Analysis

In the fourth quarter 2016, as a part of its Integrated Resource Plan process, the Southern Company system completed its regular annual updated fuel forecast, the 2017 Annual Fuel Forecast. This updated fuel forecast reflected

significantly lower long-term estimated costs for natural gas than were previously projected.
As a result of the updated long-term natural gas forecast, as well as the revised operating expense projections reflected in the discovery docket filings discussed above, on February 21, 2017, Mississippi Power filed an updated project economic viability analysis of the Kemper IGCC as required under the 2012 MPSC CPCN Order confirming authorization of the Kemper IGCC. The project economic viability analysis measures the life cycle economics of the Kemper IGCC compared to feasible alternatives, natural gas combined cycle generating units, under a variety of scenarios and considering fuel, operating and capital costs, and

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operating characteristics, as well as federal and state taxes and incentives. The reduction in the projected long-term natural gas prices in the 2017 Annual Fuel Forecast and, to a lesser extent, the increase in the estimated Kemper IGCC operating costs, negatively impact the updated project economic viability analysis.
Mississippi Power expects the Mississippi PSC to address this matter in connection with the 2017 Rate Case.
2017 Accounting Order Request
After the remainder of the plant is placed in service, AFUDC equity of approximately $11 million per month will no longer be recorded in income, and Mississippi Power expects to incur approximately $25 million per month in depreciation, taxes, operations and maintenance expenses, interest expense, and regulatory costs in excess of current rates. Mississippi Power expects to file a request for authority from the Mississippi PSC and the FERC to defer all Kemper IGCC costs incurred after the in-service date that cannot be capitalized, are not included in current rates, and are not required to be charged against earnings as a result of the $2.88 billion cost cap until such time as the Mississippi PSC completes its review and includes the resulting allowable costs in rates. In the event that the Mississippi PSC does not grant Mississippi Power's request, these monthly expenses will be charged to income as incurred and will not be recoverable through rates.
2017 Rate Case
Mississippi Power continues to believe that all costs related to the Kemper IGCC have been prudently incurred in accordance with the requirements of the 2012 MPSC CPCN Order. Mississippi Power also recognizes significant areas of potential challenge during future regulatory proceedings (and any subsequent, related legal challenges) exist. As described further herein and under "Prudence," "Lignite Mine and CO2 Pipeline Facilities," "Termination of Proposed Sale of Undivided Interest," "Bonus Depreciation," "Investment Tax Credits," and "Section 174 Research and Experimental Deduction," these challenges include, but are not limited to, prudence issues associated with capital costs, financing costs (AFUDC), and future operating costs net of chemical revenues; potential operating parameters; income tax issues; costs deferred as regulatory assets; and the 15% portion of the project previously contracted to SMEPA.
Legislation to authorize a multi-year rate plan and legislation to provide for alternate financing through securitization of up to $1.0 billion of prudently-incurred costs was enacted into law in 2013. Mississippi Power expects to utilize this legislation to securitize prudently-incurred qualifying facility costs in excess of the certificated cost estimate of $2.4 billion. Qualifying facility costs include, but are not limited to, pre-construction costs, construction costs, regulatory costs, and accrued AFUDC. The Court's decision regarding the 2013 MPSC Rate Order did not impact Mississippi Power's ability to utilize alternate financing through securitization or the February 2013 legislation.
Although the 2017 Rate Case has not yet been filed and is subject to future developments with either the Kemper IGCC or the Mississippi PSC, consistent with its approach in the 2013 and 2015 rate proceedings in accordance with the law passed in 2013 authorizing multi-year rate plans, Mississippi Power is developing both a traditional rate case requesting full cost recovery of the amounts not currently in rates and a rate mitigation plan that together represent Mississippi Power's probable filing strategy. Mississippi Power also expects that timely resolution of the 2017 Rate Case will likely require a negotiated settlement agreement. In the event an agreement acceptable to both Mississippi Power and the Mississippi Public Utilities Staff (MPUS) (and other parties) can be negotiated and ultimately approved by the Mississippi PSC, it is reasonably possible that full regulatory recovery of all Kemper IGCC costs will not occur. The impact of such an agreement on Mississippi Power's financial statements would depend on the method, amount, and type of cost recovery ultimately excluded. Certain costs, including operating costs, would be recorded to income in the period incurred, while other costs, including investment-related costs, would be charged to income when it is probable they will not be recovered and the amounts can be reasonably estimated. In the event an agreement acceptable to the parties cannot be reached, Mississippi Power intends to fully litigate its request for full recovery through the Mississippi PSC regulatory process and any subsequent legal challenges.
Mississippi Power has evaluated various scenarios in connection with its processes to prepare the 2017 Rate Case and has recognized an additional $80 million charge to income, which is the estimated minimum probable amount of the

$3.31 billion of Kemper IGCC costs not currently in rates that would not be recovered under the probable rate mitigation plan to be filed by June 3, 2017.

2015 Rate Case

On August 13, 2015, the Mississippi PSC approved Mississippi Power's request for interim rates, which presented an alternative rate proposal (In-Service Asset Proposal) designed to recover Mississippi Power's costs associated with the Kemper IGCC assets that are commercially operational and currently providing service to customers (the transmission facilities, combined cycle, natural gas pipeline, and water pipeline) and other related costs. The interim rates were designed to collect approximately $159 million annually and became effective in September 2015, subject to refund and certain other conditions.

On December 3, 2015, the Mississippi PSC issued an order (In-Service Asset Rate Order) adopting in full a stipulation (2015 Stipulation) entered into between Mississippi Power and the MPUS regarding the In-Service Asset Proposal. The In-Service Asset Rate Order provided for retail rate recovery of an annual revenue requirement of approximately $126 million, based on Mississippi Power's actual average capital structure, with a maximum common equity percentage of 49.733%, a 9.225% return on common equity, and actual embedded interest costs. The In-Service Asset Rate Order also included a prudence finding of all costs in the stipulated revenue requirement calculation for the in-service assets. The stipulated revenue requirement excluded the costs of the Kemper IGCC related to the 15% undivided interest that was previously projected to be purchased by SMEPA but reserved Mississippi Power's right to seek recovery in a future proceeding. See "Termination of Proposed Sale of Undivided Interest" herein for additional information. Mississippi Power is required to file the 2017 Rate Case by June 3, 2017.

With implementation of the new rates on December 17, 2015, the interim rates were terminated and, in March 2016, Mississippi Power completed customer refunds of approximately $11 million for the difference between the interim rates collected and the permanent rates.

2013 MPSC Rate Order

In January 2013, Mississippi Power entered into a settlement agreement with the Mississippi PSC that was intended to establish the process for resolving matters regarding cost recovery related to the Kemper IGCC (2013 Settlement Agreement). Under the 2013 Settlement Agreement, Mississippi Power agreed to limit the portion of prudently-incurred Kemper IGCC costs to be included in retail rate base to the $2.4 billion certificated cost estimate, plus the Cost Cap Exceptions, but excluding AFUDC, and any other costs permitted or determined to be excluded from the $2.88 billion cost cap by the Mississippi PSC. In March 2013, the Mississippi PSC issued a rate order approving retail rate increases of 15% effective March 19, 2013 and 3% effective January 1, 2014, which collectively were designed to collect $156 million annually beginning in 2014 (2013 MPSC Rate Order) to be used to mitigate customer rate impacts after the Kemper IGCC is placed in service, based on a mirror CWIP methodology (Mirror CWIP rate).

On February 12, 2015, the Court reversed the 2013 MPSC Rate Order based on, among other things, its findings that (1) the Mirror CWIP rate treatment was not provided for under the Baseload Act and (2) the Mississippi PSC should have determined the prudence of Kemper IGCC costs before approving rate recovery through the 2013 MPSC Rate Order. The Court also found the 2013 Settlement Agreement unenforceable due to a lack of public notice for the related proceedings. On July 7, 2015, the Mississippi PSC ordered that the Mirror CWIP rate be terminated effective July 20, 2015 and required the fourth quarter 2015 refund of the $342 million collected under the 2013 MPSC Rate Order, along with associated carrying costs of $29 million. The Court's decision did not impact the 2012 MPSC CPCN Order or the February 2013 legislation described above.

Because the 2013 MPSC Rate Order did not provide for the inclusion of CWIP in rate base as permitted by the Baseload Act, Mississippi Power continues to record AFUDC on the Kemper IGCC. Through December 31, 2016, AFUDC recorded since the original May 2014 estimated in-service date for the Kemper IGCC has totaled $398 million, which will continue to accrue at approximately $16 million per month until the remainder of the plant is placed in service. Mississippi Power has not recorded any AFUDC on Kemper IGCC costs in excess of the $2.88 billion cost cap, except for Cost Cap Exception amounts.

2012 MPSC CPCN Order

The 2012 MPSC CPCN Order included provisions relating to both Mississippi Power's recovery of financing costs during the course of construction of the Kemper IGCC and Mississippi Power's recovery of costs following the date the Kemper IGCC is placed in service. With respect to recovery of costs following the in-service date of the Kemper IGCC, the 2012 MPSC CPCN Order provided for the establishment of operational cost and revenue parameters including availability factor, heat rate, lignite heat content, and chemical revenue based upon assumptions in Mississippi Power's petition for the CPCN. Mississippi Power expects the Mississippi PSC to apply operational parameters in connection with the 2017 Rate Case and future proceedings related to the operation of the Kemper IGCC. To the extent the Mississippi PSC determines the Kemper IGCC does not meet the operational parameters ultimately adopted by the Mississippi PSC or Mississippi Power incurs additional costs to satisfy such parameters, there could be a material adverse impact on the financial statements. See "Prudence" herein for additional information.

Regulatory Assets and Liabilities

Consistent with the treatment of non-capital costs incurred during the pre-construction period, the Mississippi PSC issued an accounting order in 2011 granting Mississippi Power the authority to defer all non-capital Kemper IGCC-related costs to a

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regulatory asset through the in-service date, subject to review of such costs by the Mississippi PSC. Such costs include, but are not limited to, carrying costs on Kemper IGCC assets currently placed in service, costs associated with Mississippi PSC and MPUS consultants, prudence costs, legal fees, and operating expenses associated with assets placed in service.

In August 2014, Mississippi Power requested confirmation by the Mississippi PSC of Mississippi Power's authority to defer all operating expenses associated with the operation of the combined cycle subject to review of such costs by the Mississippi PSC. In addition, Mississippi Power is authorized to accrue carrying costs on the unamortized balance of such regulatory assets at a rate and in a manner to be determined by the Mississippi PSC in future cost recovery mechanism proceedings. Beginning in the third quarter 2015 and the second quarter 2016, in connection with the implementation of retail and wholesale rates, respectively, Mississippi Power began expensing certain ongoing project costs and certain retail debt carrying costs (associated with assets placed in service and other non-CWIP accounts) that previously were deferred as regulatory assets and began amortizing certain regulatory assets associated with assets placed in service and consulting and legal fees. The amortization periods for these regulatory assets vary from two years to 10 years as set forth in the In-Service Asset Rate Order and the settlement agreement with wholesale customers. As of December 31, 2016, the balance associated with these regulatory assets was $97 million, of which $29 million is included in current assets. Other regulatory assets associated with the remainder of the Kemper IGCC totaled $104 million as of December 31, 2016. The amortization period for these assets is expected to be determined by the Mississippi PSC in the 2017 Rate Case.

The In-Service Asset Rate Order requires Mississippi Power to submit an annual true-up calculation of its actual cost of capital, compared to the stipulated total cost of capital, with the first occurring as of May 31, 2016. At December 31, 2016, Mississippi Power's related regulatory liability included in its balance sheet totaled approximately $7 million. See "2015 Rate Case" herein for additional information.

Lignite Mine and CO_2 Pipeline Facilities

In conjunction with the Kemper IGCC, Mississippi Power owns the lignite mine and equipment and has acquired and will continue to acquire mineral reserves located around the Kemper IGCC site. The mine started commercial operation in June 2013.

In 2010, Mississippi Power executed a 40-year management fee contract with Liberty Fuels Company, LLC (Liberty Fuels), a wholly-owned subsidiary of The North American Coal Corporation, which developed, constructed, and is operating and managing the mining operations. The contract with Liberty Fuels is effective through the end of the mine reclamation. As the mining permit holder, Liberty Fuels has a legal obligation to perform mine reclamation and Mississippi Power has a contractual obligation to fund all reclamation activities. In addition to the obligation to fund the reclamation activities, Mississippi Power currently provides working capital support to Liberty Fuels through cash advances for capital purchases, payroll, and other operating expenses.

In addition, Mississippi Power has constructed and will operate the CO_2 pipeline for the planned transport of captured CO_2 for use in enhanced oil recovery. Mississippi Power entered into agreements with Denbury Onshore (Denbury) and Treetop Midstream Services, LLC (Treetop), pursuant to which Denbury would purchase 70% of the CO_2 captured from the Kemper IGCC and Treetop would purchase 30% of the CO_2 captured from the Kemper IGCC. On June 3, 2016, Mississippi Power cancelled its contract with Treetop and amended its contract with Denbury to reflect, among other things, Denbury's agreement to purchase 100% of the CO_2 captured from the Kemper IGCC, an initial contract term of 16 years, and termination rights if Mississippi Power has not satisfied its contractual obligation to deliver captured CO_2 by July 1, 2017, in addition to Denbury's existing termination rights in the event of a change in law, force majeure, or an event of default by Mississippi Power. Any termination or material modification of the agreement with Denbury could impact the operations of the Kemper IGCC and result in a material reduction in Mississippi Power's revenues to the extent Mississippi Power is not able to enter into other similar contractual arrangements or otherwise sequester the CO_2 produced. Additionally, sustained oil price reductions could result in significantly lower revenues than Mississippi Power originally forecasted to be available to offset customer rate

impacts, which could have a material impact on Mississippi Power's financial statements.
The ultimate outcome of these matters cannot be determined at this time.
Termination of Proposed Sale of Undivided Interest
In 2010 and as amended in 2012, Mississippi Power and SMEPA entered into an agreement whereby SMEPA agreed to purchase a 15% undivided interest in the Kemper IGCC (15% Undivided Interest). On May 20, 2015, SMEPA notified Mississippi Power of its termination of the agreement. Mississippi Power previously received a total of $275 million of deposits from SMEPA that were required to be returned to SMEPA with interest. On June 3, 2015, Southern Company, pursuant to its guarantee obligation, returned approximately $301 million to SMEPA. Subsequently, Mississippi Power issued a promissory note in the aggregate principal amount of approximately $301 million to Southern Company, which matures on December 1, 2017.

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Litigation
On April 26, 2016, a complaint against Mississippi Power was filed in Harrison County Circuit Court (Circuit Court) by Biloxi Freezing & Processing Inc., Gulfside Casino Partnership, and John Carlton Dean, which was amended and refiled on July 11, 2016 to include, among other things, Southern Company as a defendant. On August 12, 2016, Southern Company and Mississippi Power removed the case to the U.S. District Court for the Southern District of Mississippi. The plaintiffs filed a request to remand the case back to state court, which was granted on November 17, 2016. The individual plaintiff, John Carlton Dean, alleges that Mississippi Power and Southern Company violated the Mississippi Unfair Trade Practices Act. All plaintiffs have alleged that Mississippi Power and Southern Company concealed, falsely represented, and failed to fully disclose important facts concerning the cost and schedule of the Kemper IGCC and that these alleged breaches have unjustly enriched Mississippi Power and Southern Company. The plaintiffs seek unspecified actual damages and punitive damages; ask the Circuit Court to appoint a receiver to oversee, operate, manage, and otherwise control all affairs relating to the Kemper IGCC; ask the Circuit Court to revoke any licenses or certificates authorizing Mississippi Power or Southern Company to engage in any business related to the Kemper IGCC in Mississippi; and seek attorney's fees, costs, and interest. The plaintiffs also seek an injunction to prevent any Kemper IGCC costs from being charged to customers through electric rates. On December 7, 2016, Southern Company and Mississippi Power filed motions to dismiss.
On June 9, 2016, Treetop, Greenleaf, Tenrgys, LLC, Tellus Energy, LLC, WCOA, LLC, and Tellus Operating Group filed a complaint against Mississippi Power, Southern Company, and SCS in the state court in Gwinnett County, Georgia. The complaint relates to the cancelled CO_2 contract with Treetop and alleges fraudulent misrepresentation, fraudulent concealment, civil conspiracy, and breach of contract on the part of Mississippi Power, Southern Company, and SCS and seeks compensatory damages of $100 million, as well as unspecified punitive damages. Southern Company, Mississippi Power, and SCS have moved to compel arbitration pursuant to the terms of the CO_2 contract. Southern Company believes these legal challenges have no merit; however, an adverse outcome in these proceedings could have an impact on Southern Company's results of operations, financial condition, and liquidity. Southern Company will vigorously defend itself in these matters, and the ultimate outcome of these matters cannot be determined at this time.
Baseload Act
In 2008, the Baseload Act was signed by the Governor of Mississippi. The Baseload Act authorizes, but does not require, the Mississippi PSC to adopt a cost recovery mechanism that includes in retail base rates, prior to and during construction, all or a portion of the prudently-incurred pre-construction and construction costs incurred by a utility in constructing a base load electric generating plant. Prior to the passage of the Baseload Act, such costs would traditionally be recovered only after the plant was placed in service. The Baseload Act also provides for periodic prudence reviews by the Mississippi PSC and prohibits the cancellation of any such generating plant without the approval of the Mississippi PSC. In the event of cancellation of the construction of the plant without approval of the Mississippi PSC, the Baseload Act authorizes the Mississippi PSC to make a public interest determination as to whether and to what extent the utility will be afforded rate recovery for costs incurred in connection with such cancelled generating plant. See "Rate Recovery of Kemper IGCC Costs" herein for additional information.
Bonus Depreciation
In December 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. Bonus depreciation was extended for qualified property placed in service through 2020. The PATH Act allows for 50% bonus depreciation for 2015 through 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 bonus depreciation included in the PATH Act is expected to result in approximately $20 million of positive cash flows for the 2016 tax year, which was not all realized in 2016 due to a projected consolidated net operating loss (NOL) for Southern Company. Dependent upon placing the remainder of the Kemper IGCC in service by December 31, 2017, Mississippi Power expects approximately $370 million of positive cash flows from bonus depreciation for the 2017 tax year, which may not all be realized in 2017

due to additional NOL projections for the 2017 tax year. See "Kemper IGCC Schedule and Cost Estimate" herein and Note 5 under "Current and Deferred Income Taxes – Net Operating Loss" for additional information. The ultimate outcome of this matter cannot be determined at this time.

Investment Tax Credits

The IRS allocated $133 million (Phase I) and $279 million (Phase II) of Internal Revenue Code Section 48A tax credits to Mississippi Power in connection with the Kemper IGCC. These tax credits were dependent upon meeting the IRS certification requirements, including an in-service date no later than May 11, 2014 for the Phase I credits and April 19, 2016 for the Phase II credits. In addition, the capture and sequestration (via enhanced oil recovery) of at least 65% of the CO_2 produced by the Kemper IGCC during operations in accordance with the Internal Revenue Code was also a requirement of the Phase II credits. As a result

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of schedule extensions for the Kemper IGCC, the Phase I tax credits were recaptured in 2013 and the Phase II tax credits were recaptured in 2015.

Section 174 Research and Experimental Deduction

Southern Company reflected deductions for research and experimental (R&E) expenditures related to the Kemper IGCC in its federal income tax calculations since 2013 and has filed amended federal income tax returns for 2008 through 2013 to also include such deductions. The Kemper IGCC is based on first-of-a-kind technology, and Southern Company believes that a significant portion of the plant costs qualify as deductible R&E expenditures under Internal Revenue Code Section 174. In December 2016, Southern Company and the IRS reached a proposed settlement, subject to approval of the U.S. Congress Joint Committee on Taxation, resolving a methodology for these deductions. Due to the uncertainty related to this tax position, Southern Company had unrecognized tax benefits associated with these R&E deductions totaling approximately $464 million as of December 31, 2016. See Note 5 under "Unrecognized Tax Benefits" for additional information. This matter is expected to be resolved in the next 12 months; however, the ultimate outcome of this matter cannot be determined at this time.

4. JOINT OWNERSHIP AGREEMENTS

Alabama Power owns an undivided interest in Units 1 and 2 at Plant Miller and related facilities jointly with PowerSouth Energy Cooperative, Inc. Georgia Power owns undivided interests in Plants Vogtle, Hatch, Wansley, and Scherer in varying amounts jointly with one or more of the following entities: OPC, MEAG Power, the City of Dalton, Georgia, Florida Power & Light Company, and Jacksonville Electric Authority. In addition, Georgia Power has joint ownership agreements with OPC for the Rocky Mountain facilities. On August 31, 2016, Georgia Power sold its 33% ownership interest in the Intercession City combustion turbine unit to Duke Energy Florida, LLC. Southern Power owns an undivided interest in Plant Stanton Unit A and related facilities jointly with the Orlando Utilities Commission, Kissimmee Utility Authority, and Florida Municipal Power Agency.

At December 31, 2016, Alabama Power's, Georgia Power's, and Southern Power's percentage ownership and investment (exclusive of nuclear fuel) in jointly-owned facilities in commercial operation with the above entities were as follows:

Facility (Type)	Percent Ownership	Plant in Service	Accumulated Depreciation	CWIP
		(in millions)		
Plant Vogtle (nuclear) Units 1 and 2	45.7 %	$3,545	$ 2,111	$ 74
Plant Hatch (nuclear)	50.1	1,297	585	81
Plant Miller (coal) Units 1 and 2	91.8	1,657	587	23
Plant Scherer (coal) Units 1 and 2	8.4	258	90	3
Plant Wansley (coal)	53.5	1,046	308	12
Rocky Mountain (pumped storage)	25.4	181	129	—
Plant Stanton (combined cycle) Unit A	65.0	155	58	—

Georgia Power also owns 45.7% of Plant Vogtle Units 3 and 4, which are currently under construction and had a CWIP balance of approximately $3.9 billion as of December 31, 2016. See Note 3 under "Regulatory Matters – Georgia Power – Nuclear Construction" for additional information.

Alabama Power and Georgia Power have contracted to operate and maintain their jointly-owned facilities, except for Rocky Mountain, as agents for their respective co-owners. Southern Power has a service agreement with SCS whereby SCS is responsible for the operation and maintenance of Plant Stanton Unit A. The companies' proportionate share of their plant operating expenses is included in the corresponding operating expenses in the statements of income and each company is responsible for providing its own financing.

Southern Company Gas has a 50% undivided ownership interest with The Williams Companies, Inc. in a 115-mile pipeline facility being constructed in northwest Georgia. The CWIP balance representing Southern Company Gas' share of construction costs was approximately $124 million as of December 31, 2016. Southern Company Gas also has an agreement to lease its 50% undivided ownership in the pipeline facility once it is placed in service, which is currently expected to be later in 2017. Under the lease, Southern Company Gas will receive approximately $26 million annually for an initial term of 25 years. The lessee will be responsible for maintaining the pipeline during the lease term and for providing service to transportation customers under its FERC-regulated tariff.

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5. INCOME TAXES

Southern Company files a consolidated federal income tax return and various state income tax returns, some of which are combined or unitary. 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. PowerSecure and Southern Company Gas became participants in the income tax allocation agreement as of May 9, 2016 and July 1, 2016, respectively. 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:

	2016	2015	2014
	(in millions)		
Federal —			
Current	$1,184	$(177)	$175
Deferred	(342)	1,266	695
	842	1,089	870
State —			
Current	(108)	(33)	93
Deferred	217	138	14
	109	105	107
Total	$951	$1,194	$977

Net cash payments (refunds) for income taxes in 2016, 2015, and 2014 were $(148) million, $(9) million, and $272 million, respectively.

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The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2016	2015
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation	$15,392	$12,767
Property basis differences	2,708	1,603
Leveraged lease basis differences	314	308
Employee benefit obligations	737	579
Premium on reacquired debt	89	95
Regulatory assets associated with employee benefit obligations	1,584	1,378
Regulatory assets associated with AROs	1,781	1,422
Other	907	793
Total	23,512	18,945
Deferred tax assets —		
Federal effect of state deferred taxes	597	479
Employee benefit obligations	1,868	1,720
Over recovered fuel clause	66	104
Other property basis differences	401	695
Deferred costs	100	83
ITC carryforward	1,974	770
Federal NOL carryforward	1,084	38
Unbilled revenue	92	111
Other comprehensive losses	152	85
AROs	1,732	1,482
Estimated Loss on Kemper IGCC	484	451
Deferred state tax assets	266	222
Other	679	443
Total	9,495	6,683
Valuation allowance	(23)	(4)
Total deferred income taxes	14,040	12,266
Portion included in accumulated deferred tax assets	(52)	(56)
Accumulated deferred income taxes	$14,092	$12,322

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

At December 31, 2016, the tax-related regulatory assets to be recovered from customers were $1.6 billion. 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, 2016, the tax-related regulatory liabilities to be credited to customers were $219 million. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized ITCs.

In accordance with regulatory requirements, deferred federal ITCs for the traditional electric operating companies are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $22 million in 2016, $21 million in 2015, and $22 million in 2014. Southern Power's deferred federal ITCs are amortized to income tax expense over the life of the asset. Credits amortized in this manner amounted to $37 million in 2016, $19 million in 2015, and

$11 million in 2014. Also, Southern Power received cash related to federal ITCs under the renewable energy incentives of $162 million and $74 million for the years ended December 31, 2015 and 2014, respectively. No cash was received related to these incentives in 2016. Furthermore, the tax basis of the asset is reduced by 50% of the ITCs received, resulting in a net deferred tax asset. Southern Power has elected to recognize the tax benefit of this basis difference as a reduction to income tax expense in the year in which the plant reaches commercial operation. The tax benefit of the related basis differences reduced income tax expense by $173 million in 2016, $54 million in 2015, and $48 million in 2014. See "Unrecognized Tax Benefits" below for further information.

Tax Credit Carryforwards

At December 31, 2016, Southern Company had federal ITC and PTC carryforwards (primarily related to Southern Power) which are expected to result in $1.8 billion of federal income tax benefits. The federal ITC carryforwards begin expiring in 2032 but are expected to be fully utilized by 2022. The PTC carryforwards begin expiring in 2036 but are expected to be fully utilized by 2022. The acquisition of additional renewable projects and carrying back the federal NOL, as well as potential tax reform legislation on existing renewable incentives, could further delay existing tax credit carryforwards. The ultimate outcome of these matters cannot be determined at this time.

Additionally, Southern Company had state ITC carryforwards for the state of Georgia totaling $202 million, which begin expiring in 2020 but are expected to be fully utilized.

Net Operating Loss

At December 31, 2016, Southern Company had a consolidated federal NOL carryforward of $3 billion, of which $2.8 billion is projected for the 2016 tax year. The federal NOL will begin expiring in 2033. However, portions of the NOL are expected to be carried back to prior tax years and forward to future tax years. The ultimate outcome of this matter cannot be determined at this time.

At December 31, 2016, the state NOL carryforwards for Southern Company's subsidiaries were as follows:

Jurisdiction	NOL Carryforwards	Net State Income Tax Benefit	Tax Year NOL Begins Expiring
	(in millions)		
Mississippi	$ 3,448	$ 112	2032
Oklahoma	839	31	2036
Georgia	685	25	2019
New York	229	11	2036
New York City	209	12	2036
Florida	198	7	2034
Other states	146	5	Various
Total	$ 5,754	$ 203	

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Effective Tax Rate

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

	2016	2015	2014
Federal statutory rate	35.0 %	35.0 %	35.0 %
State income tax, net of federal deduction	2.1	1.9	2.3
Employee stock plans dividend deduction	(1.2)	(1.2)	(1.4)
Non-deductible book depreciation	0.9	1.2	1.4
AFUDC-Equity	(2.0)	(2.2)	(2.9)
ITC basis difference	(5.0)	(1.5)	(1.6)
Federal PTCs	(1.2)	—	—
Amortization of ITC	(0.9)	(0.5)	(0.5)
Other	(0.4)	0.2	0.2
Effective income tax rate	27.3 %	32.9 %	32.5 %

Southern Company's effective tax rate is typically lower than the statutory rate due to employee stock plans' dividend deduction, non-taxable AFUDC equity, and federal income tax benefits from ITCs and PTCs.

On March 30, 2016, the FASB issued ASU 2016-09, which changes the accounting for income taxes for share-based payment award transactions. Entities are required to recognize all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation as income tax expense or benefit in the income statement. The adoption of ASU 2016-09 did not have a material impact on Southern Company's overall effective tax rate. See Note 1 under "Recently Issued Accounting Standards" for additional information.

Unrecognized Tax Benefits

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

	2016	2015	2014
	(in millions)		
Unrecognized tax benefits at beginning of year	$433	$170	$7
Tax positions increase from current periods	45	43	64
Tax positions increase from prior periods	21	240	102
Tax positions decrease from prior periods	(15)	(20)	(3)
Balance at end of year	$484	$433	$170

The tax positions increase from current and prior periods for 2016 and 2015 relate primarily to deductions for R&E expenditures associated with the Kemper IGCC and federal income tax benefits from deferred ITCs. See Note 3 under "Integrated Coal Gasification Combined Cycle" and "Section 174 Research and Experimental Deduction" herein for more information. The tax positions decrease from prior periods for 2016 and 2015 relates to federal income tax benefits from deferred ITCs.

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

	2016	2015	2014
	(in millions)		
Tax positions impacting the effective tax rate	$20	$10	$10
Tax positions not impacting the effective tax rate	464	423	160
Balance of unrecognized tax benefits	$484	$433	$170

The tax positions impacting the effective tax rate primarily relate to federal deferred income tax credits and Southern Company's estimate of the uncertainty related to the amount of those benefits. If these tax positions are not able to be recognized due to a federal audit adjustment in the amount that has been estimated, the amount of tax credit carryforwards discussed above would be reduced by approximately $92 million. The tax positions not impacting the effective tax rate for 2016, 2015, and 2014 relate to deductions for R&E expenditures associated with the Kemper IGCC. See "Section 174 Research and Experimental Deduction"

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herein for more information. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

Accrued interest for all tax positions other than the Section 174 R&E deductions was immaterial for all years presented.

Southern Company classifies interest on tax uncertainties as interest expense. Southern 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 and the U.S. Congress Joint Committee on Taxation approval of the R&E expenditures associated with the Kemper IGCC could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined. See "Section 174 Research and Experimental Deduction" herein for more information.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013, 2014, and 2015 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 Southern Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2011.

Section 174 Research and Experimental Deduction

Southern Company reflected deductions for R&E expenditures related to the Kemper IGCC in its federal income tax calculations since 2013 and filed amended federal income tax returns for 2008 through 2013 to also include such deductions.

The Kemper IGCC is based on first-of-a-kind technology, and Southern Company believes that a significant portion of the plant costs qualify as deductible R&E expenditures under Internal Revenue Code Section 174. In December 2016, Southern Company and the IRS reached a proposed settlement, subject to approval of the U.S. Congress Joint Committee on Taxation, resolving a methodology for these deductions. Due to the uncertainty related to this tax position, Southern Company had unrecognized tax benefits associated with these R&E deductions totaling approximately $464 million and associated interest of $28 million as of December 31, 2016. This matter is expected to be resolved in the next 12 months; however, the ultimate outcome of this matter cannot be determined at this time. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

6. FINANCING

Long-Term Debt Payable to an Affiliated Trust

Alabama Power 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 Alabama Power through the issuance of junior subordinated notes totaling $206 million as of December 31, 2016 and 2015, which constitute substantially all of the assets of this trust and are reflected in the balance sheets as long-term debt payable. Alabama Power 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, 2016 and 2015, trust preferred securities of $200 million were outstanding.

Securities Due Within One Year

A summary of scheduled maturities and redemptions of securities due within one year at December 31 was as follows:

	2016	2015
	(in millions)	
Senior notes	$1,995	$1,810
Other long-term debt	485	829
Pollution control revenue bonds(*)	76	4
Capitalized leases	32	32
Unamortized debt issuance expense	(1)	(1)

Total	$2,587	$2,674

(*) Includes $40 million of pollution control revenue bonds classified as short-term since they are variable rate demand obligations that are supported by short-term credit facilities; however, the final maturity date is in 2028.

Maturities through 2021 applicable to total long-term debt are as follows: $2.6 billion in 2017; $3.9 billion in 2018; $3.2 billion in 2019; $1.4 billion in 2020; and $3.1 billion in 2021.

Bank Term Loans

Southern Company and certain of its subsidiaries have entered into various bank term loan agreements. At December 31, 2016, Southern Company, Alabama Power, Gulf Power, Mississippi Power, and Southern Power Company had outstanding bank term loans totaling $400 million, $45 million, $100 million, $1.2 billion, and $380 million, respectively, of which $2.0 billion are reflected in the statements of capitalization as long-term debt and $100 million are reflected in the balance sheet as notes payable. At December 31, 2015, Southern Company, Mississippi Power, and Southern Power Company had outstanding bank term loans totaling $400 million, $900 million, and $400 million, respectively.

In March 2016, Alabama Power entered into three bank term loan agreements with maturity dates of March 2021, in an aggregate principal amount of $45 million, one of which bears interest at 2.38% per annum and two of which bear interest based on three-month LIBOR.

In March 2016, Mississippi Power entered into an unsecured term loan agreement with a syndicate of financial institutions for an aggregate amount of $1.2 billion. Mississippi Power borrowed $900 million in March 2016 under the term loan agreement and the remaining $300 million in October 2016. Mississippi Power used the initial proceeds to repay $900 million in maturing bank loans in March 2016 and the remaining $300 million to repay at maturity Mississippi Power's Series 2011A 2.35% Senior Notes due October 15, 2016. This loan matures on April 1, 2018 and bears interest based on one-month LIBOR.

In May 2016, Gulf Power entered into an 11-month floating rate bank loan bearing interest based on one-month LIBOR. This short-term loan was for $100 million aggregate principal amount and the proceeds were used to repay existing indebtedness and for working capital and other general corporate purposes.

In September 2016, Southern Power Company repaid $80 million of an outstanding $400 million floating rate bank loan and extended the maturity date of the remaining $320 million from September 2016 to September 2018. In addition, Southern Power Company entered into a $60 million aggregate principal amount floating rate bank loan bearing interest based on one-month LIBOR due September 2017. The proceeds were used to repay existing indebtedness and for other general corporate purposes.

The outstanding bank loans as of December 31, 2016 have covenants that limit debt levels to a percentage of total capitalization. The percentage is 70% for Southern Company and 65% for Alabama Power, Gulf Power, Mississippi Power, and Southern Power Company, as defined in the agreements. For purposes of these definitions, debt excludes any long-term debt payable to affiliated trusts, other hybrid securities, and, for Southern Company and Mississippi Power, any securitized debt relating to the securitization of certain costs of the Kemper IGCC. Additionally, for Southern Company and Southern Power Company, for purposes of these definitions, debt excludes any project debt incurred by certain subsidiaries of Southern Power Company to the extent such debt is non-recourse to Southern Power Company and capitalization excludes the capital stock or other equity attributable to such subsidiary. At December 31, 2016, each of Southern Company, Alabama Power, Gulf Power, Mississippi Power, and Southern Power Company was in compliance with its debt limits.

DOE Loan Guarantee Borrowings

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

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

All borrowings under the FFB Credit Facility are full recourse to Georgia Power, and Georgia Power is obligated to reimburse the DOE for any payments the DOE is required to make to the FFB under the guarantee. Georgia Power's reimbursement obligations to the DOE are full recourse and secured by a first priority lien on (i) Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor core) and (ii) Georgia Power's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. There are no restrictions on Georgia Power's ability to grant liens on other property.

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Advances may be requested under the FFB Credit Facility on a quarterly basis through 2020. The final maturity date for each advance under the FFB Credit Facility is February 20, 2044. Interest is payable quarterly and principal payments will begin on February 20, 2020. Borrowings under the FFB Credit Facility will bear interest at the applicable U.S. Treasury rate plus a spread equal to 0.375%.
In connection with its entry into the agreements with the DOE and the FFB, Georgia Power incurred issuance costs of approximately $66 million, which are being amortized over the life of the borrowings under the FFB Credit Facility.
In June and December 2016, Georgia Power made borrowings under the FFB Credit Facility in an aggregate principal amount of $300 million and $125 million, respectively. The interest rate applicable to the $300 million principal amount is 2.571% and the interest rate applicable to the $125 million principal amount is 3.142%, both for an interest period that extends to the final maturity date of February 20, 2044.
At December 31, 2016 and 2015, Georgia Power had $2.6 billion and $2.2 billion of borrowings outstanding under the FFB Credit Facility, respectively. Future advances are subject to satisfaction of customary conditions, as well as certification of compliance with the requirements of the Title XVII Loan Guarantee Program, including accuracy of project-related representations and warranties, delivery of updated project-related information, and evidence of compliance with the prevailing wage requirements of the Davis-Bacon Act of 1931, as amended, and certification from the DOE's consulting engineer that proceeds of the advances are used to reimburse Eligible Project Costs.
Under the Loan Guarantee Agreement, Georgia Power is subject to customary borrower affirmative and negative covenants and events of default. In addition, Georgia Power is subject to project-related reporting requirements and other project-specific covenants and events of default.
In the event certain mandatory prepayment events occur, the FFB's commitment to make further advances under the FFB Credit Facility will terminate and Georgia Power will be required to prepay the outstanding principal amount of all borrowings under the FFB Credit Facility over a period of five years (with level principal amortization). Among other things, these mandatory prepayment events include (i) the termination of the Vogtle 3 and 4 Agreement; (ii) cancellation of Plant Vogtle Units 3 and 4 by the Georgia PSC, or by Georgia Power if authorized by the Georgia PSC; and (iii) cost disallowances by the Georgia PSC that could have a material adverse effect on completion of Plant Vogtle Units 3 and 4 or Georgia Power's ability to repay the outstanding borrowings under the FFB Credit Facility. Under certain circumstances, insurance proceeds and any proceeds from an event of taking must be applied to immediately prepay outstanding borrowings under the FFB Credit Facility. Georgia Power also may voluntarily prepay outstanding borrowings under the FFB Credit Facility. Under the FFB Promissory Note, any prepayment (whether mandatory or optional) will be made with a make-whole premium or discount, as applicable.
In connection with any cancellation of Plant Vogtle Units 3 and 4 that results in a mandatory prepayment event, the DOE may elect to continue construction of Plant Vogtle Units 3 and 4. In such an event, the DOE will have the right to assume Georgia Power's rights and obligations under the principal agreements relating to Plant Vogtle Units 3 and 4 and to acquire all or a portion of Georgia Power's ownership interest in Plant Vogtle Units 3 and 4.
Senior Notes
Southern Company and its subsidiaries issued a total of $13.3 billion of senior notes in 2016. Southern Company issued $8.5 billion and its subsidiaries issued a total of $4.8 billion. These amounts include senior notes issued by Southern Company Gas subsequent to the Merger. The proceeds of Southern Company's issuances were used to fund a portion of the consideration for the Merger and related transaction costs and for general corporate purposes. Except as described below, the proceeds of Southern Company's subsidiaries' issuances were used to repay long-term indebtedness, to repay short-term indebtedness, and for other general corporate purposes, including the applicable subsidiaries' continuous construction programs, and, for Southern Power, its growth strategy. Certain of Georgia Power's and Southern Power's issuances were allocated to eligible renewable energy expenditures. The proceeds of Southern Company Gas' issuances were primarily used to repay a $360 million promissory note issued to Southern Company for the purpose of funding a portion of the purchase price for a 50% equity interest in Southern Natural Gas Company, L.L.C. (SNG), to fund the purchase of Piedmont Natural Gas Company, Inc.'s (Piedmont) interest in

SouthStar Energy Services, LLC (SouthStar), and to make a voluntary contribution to Southern Company Gas' pension plan. See Note 12 under "Southern Company – Investment in Southern Natural Gas" and " – Acquisition of Remaining Interest in SouthStar" for additional information.

At December 31, 2016 and 2015, Southern Company and its subsidiaries had a total of $33.0 billion and $19.1 billion, respectively, of senior notes outstanding. At December 31, 2016 and 2015, Southern Company had a total of $10.3 billion and $2.4 billion, respectively, of senior notes outstanding. These amounts include senior notes due within one year.

Subsequent to December 31, 2016, Alabama Power repaid at maturity $200 million aggregate principal amount of its Series 2007A 5.55% Senior Notes due February 1, 2017.

Since Southern Company is a holding company, the right of Southern Company and, hence, the right of creditors of Southern Company (including holders of Southern Company senior notes) to participate in any distribution of the assets of any subsidiary of Southern Company, whether upon liquidation, reorganization or otherwise, is subject to prior claims of creditors and preferred and preference stockholders of such subsidiary.

Junior Subordinated Notes

At December 31, 2016 and 2015, Southern Company had a total of $2.4 billion and $1.0 billion, respectively, of junior subordinated notes outstanding.

In September 2016, Southern Company issued $800 million aggregate principal amount of Series 2016A 5.25% Junior Subordinated Notes due October 1, 2076. The proceeds were used to repay short-term indebtedness that was incurred to repay at maturity $500 million aggregate principal amount of Southern Company's Series 2011A 1.95% Senior Notes due September 1, 2016 and for other general corporate purposes.

In December 2016, Southern Company issued $550 million aggregate principal amount of Series 2016B Junior Subordinated Notes due March 15, 2057, which bear interest at a fixed rate of 5.50% per year up to, but not including, March 15, 2022. From, and including, March 15, 2022, the Series 2016B Junior Subordinated Notes will bear interest at a floating rate based on three-month LIBOR. The proceeds were used for general corporate purposes.

Pollution Control Revenue Bonds

Pollution control revenue bond obligations represent loans to the traditional electric operating companies from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. In some cases, the pollution control revenue bond obligations represent obligations under installment sales agreements with respect to facilities constructed with the proceeds of revenue bonds issued by public authorities. The traditional electric operating companies had $3.3 billion of outstanding pollution control revenue bond obligations at December 31, 2016 and 2015, which includes pollution control revenue bonds due within one year. The traditional electric operating companies are required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

Plant Daniel Revenue Bonds

In 2011, in connection with Mississippi Power's election under its operating lease of Plant Daniel Units 3 and 4 to purchase the assets, Mississippi Power assumed the obligations of the lessor related to $270 million aggregate principal amount of Mississippi Business Finance Corporation Taxable Revenue Bonds, 7.13% Series 1999A due October 20, 2021, issued for the benefit of the lessor. See "Assets Subject to Lien" herein for additional information.

Gas Facility Revenue Bonds

Pivotal Utility Holdings, Inc., a subsidiary of Southern Company Gas, is party to a series of loan agreements with the New Jersey Economic Development Authority and Brevard County, Florida under which five series of gas facility revenue bonds have been issued with maturities ranging from 2022 to 2033. These revenue bonds are issued by state agencies or counties to investors, and proceeds from the issuance then are loaned to Southern Company Gas. The amount of gas facility revenue bonds outstanding at December 31, 2016 was $200 million.

Other Revenue Bonds

Other revenue bond obligations represent loans to Mississippi Power from a public authority of funds derived from the sale by such authority of revenue bonds issued to finance a portion of the costs of constructing the Kemper IGCC and related facilities.

Mississippi Power had $50 million of such obligations outstanding related to tax-exempt revenue bonds at December 31, 2016 and 2015. Such amounts are reflected in the statements of capitalization as long-term senior notes and debt.

First Mortgage Bonds

Nicor Gas, a subsidiary of Southern Company Gas, had $625 million of first mortgage bonds outstanding at December 31, 2016. These bonds have been issued with maturities ranging from 2019 to 2038. Substantially all of Nicor Gas' properties are subject to the lien of the indenture securing these first mortgage bonds. See "Assets Subject to Lien" herein for additional information.

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Capital Leases

Assets acquired under capital leases are recorded in the balance sheets as property, plant, and equipment and the related obligations are classified as long-term debt.

In 2013, Mississippi Power entered into a nitrogen supply agreement for the air separation unit of the Kemper IGCC, which resulted in a capital lease obligation at December 31, 2016 and 2015 of approximately $74 million and $77 million, respectively, with an annual interest rate of 4.9% for both years. Amortization of the capital lease asset for the air separation unit will begin when the Kemper IGCC is placed in service. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

At December 31, 2016 and 2015, the capitalized lease obligations for Georgia Power's corporate headquarters building were $28 million and $35 million, respectively, with an annual interest rate of 7.9% for both years.

At December 31, 2016 and 2015, Alabama Power had capitalized lease obligations of $4 million and $5 million, respectively, for a natural gas pipeline with an annual interest rate of 6.9%.

At December 31, 2016 and 2015, a subsidiary of Southern Company had capital lease obligations of approximately $29 million and $30 million, respectively, for certain computer equipment including desktops, laptops, servers, printers, and storage devices with annual interest rates that range from 1.4% to 3.4%.

Assets Subject to Lien

Each of Southern Company's subsidiaries is organized as a legal entity, separate and apart from Southern Company and its other subsidiaries. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its other subsidiaries.

Gulf Power has granted one or more liens on certain of its property in connection with the issuance of certain series of pollution control revenue bonds with an aggregate outstanding principal amount of $41 million as of December 31, 2016.

The revenue bonds assumed in conjunction with Mississippi Power's purchase of Plant Daniel Units 3 and 4 are secured by Plant Daniel Units 3 and 4 and certain related personal property. See "Plant Daniel Revenue Bonds" herein for additional information.

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

The first mortgage bonds issued by Nicor Gas are secured by substantially all of Nicor Gas' properties. See "First Mortgage Bonds" herein for additional information.

During 2016, in accordance with its overall growth strategy, Southern Power acquired the Mankato project. Under the terms of the remaining 10-year PPA and the 20-year expansion PPA, approximately $408 million of assets, primarily related to property, plant, and equipment, are subject to lien at December 31, 2016. See Note 12 under "Southern Power" for additional information.

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Bank Credit Arrangements

At December 31, 2016, committed credit arrangements with banks were as follows:

Company	Expires					Executable Term Loans		Expires Within One Year	
	2017	2018	2020	Total	Unused	One Year	Two Years	Term Out	No Term Out
	(in millions)			(in millions)		(in millions)		(in millions)	
Southern Company[(a)]	$—	$1,000	$1,250	$2,250	$2,250	$—	$ —	$ —	$ —
Alabama Power	35	500	800	1,335	1,335	—	—	—	35
Georgia Power	—	—	1,750	1,750	1,732	—	—	—	—
Gulf Power	85	195	—	280	280	45	—	25	60
Mississippi Power	173	—	—	173	150	—	13	13	160
Southern Power Company[(b)]	—	—	600	600	522	—	—	—	—
Southern Company Gas[(c)]	75	1,925	—	2,000	1,949	—	—	—	75
Other	55	—	—	55	55	20	—	20	35
Southern Company Consolidated	$423	$3,620	$4,400	$8,443	$8,273	$ 65	$ 13	$ 58	$ 365

(a) Represents the Southern Company parent entity.

(b) Excludes credit agreements (Project Credit Facilities) assumed with the acquisition of certain solar facilities, which were non-recourse to Southern Power Company, the proceeds of which were used to finance project costs related to such solar facilities. See Note 12 under "Southern Power" for additional information. Also excludes a $120 million continuing letter of credit facility entered into by Southern Power in December 2016 for standby letters of credit expiring in 2019. At December 31, 2016, the total amount available under the letter of credit facility was $82 million.

(c) Southern Company Gas, as the parent entity, guarantees the obligations of Southern Company Gas Capital, which is the borrower of $1.3 billion of these arrangements. Southern Company Gas' committed credit arrangements also include $700 million for which Nicor Gas is the borrower and which is restricted for working capital needs of Nicor Gas.

Most of the bank credit arrangements require payment of commitment fees based on the unused portion of the commitments or the maintenance of compensating balances with the banks. Commitment fees average less than 1/4 of 1% for Southern Company, the traditional electric operating companies, Southern Power Company, Southern Company Gas, and Nicor Gas. Compensating balances are not legally restricted from withdrawal.

Subject to applicable market conditions, Southern Company and its subsidiaries expect to renew or replace their bank credit arrangements as needed, prior to expiration. In connection therewith, Southern Company and its subsidiaries may extend the maturity dates and/or increase or decrease the lending commitments thereunder.

Southern Company's, Southern Company Gas', and Nicor Gas' credit arrangements contain covenants that limit debt levels to 70% of total capitalization, as defined in the agreements, and most of these other bank credit arrangements contain covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes the long-term debt payable to affiliated trusts and, in certain arrangements, other hybrid securities, and, for Southern Company and Mississippi Power, any securitized debt relating to the securitization of certain costs of the Kemper IGCC. Additionally, for Southern Company and Southern Power Company, for purposes of these definitions, debt excludes any project debt incurred by certain subsidiaries of Southern Power Company to the extent such debt is non-recourse to Southern Power Company and capitalization excludes the capital stock or other equity attributable to such subsidiaries. At December 31, 2016, Southern Company, the traditional electric operating companies, Southern Power Company, Southern Company Gas, and Nicor Gas were each in compliance with their respective debt limit covenants.

A portion of the $8.3 billion unused credit with banks is allocated to provide liquidity support to the pollution control revenue bonds of the traditional electric operating companies and the commercial paper programs of Southern Company, the traditional electric operating companies, Southern Power Company, Southern Company Gas, and Nicor Gas. The amount of variable rate pollution control revenue bonds of the traditional electric operating companies outstanding requiring liquidity support as of December 31, 2016 was approximately $1.9 billion. In addition, at December 31, 2016, the traditional electric operating companies had approximately $0.4 billion of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

Southern Company, the traditional electric operating companies, Southern Power Company, Southern Company Gas, and Nicor Gas make short-term borrowings primarily through commercial paper programs that have the liquidity support of the committed

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bank credit arrangements described above. Commercial paper and short-term bank term loans are included in notes payable in the balance sheets.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		
	Amount Outstanding	Weighted Average Interest Rate	
	(in millions)		
December 31, 2016:			
Commercial paper	$ 1,909	1.1	%
Short-term bank debt	123	1.7	%
Total	$ 2,032	1.1	%
December 31, 2015:			
Commercial paper	$ 740	0.7	%
Short-term bank debt	500	1.4	%
Total	$ 1,240	0.9	%

In addition to the short-term borrowings in the table above, Southern Power's subsidiary Project Credit Facilities had total amounts outstanding of $209 million and $137 million at a weighted average interest rate of 2.1% and 2.0% as of December 31, 2016 and 2015, respectively. The amounts outstanding as of December 31, 2016 under the Project Credit Facilities were fully repaid subsequent to December 31, 2016.

Redeemable Preferred Stock of Subsidiaries

Each of the traditional electric operating companies has issued preferred and/or preference stock. The preferred stock of Alabama Power and Mississippi Power contains a feature that allows the holders to elect a majority of such subsidiary'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 Alabama Power and Mississippi Power, this preferred stock is presented as "Redeemable Preferred Stock of Subsidiaries" in a manner consistent with temporary equity under applicable accounting standards. The preferred and preference stock at Georgia Power and the preference stock at Alabama Power and Gulf Power do not contain such a provision. As a result, under applicable accounting standards, the preferred and preference stock at Georgia Power and the preference stock at Alabama Power and Gulf Power are presented as "Preferred and Preference Stock of Subsidiaries," a separate component of "Stockholders' Equity," on Southern Company's balance sheets, statements of capitalization, and statements of stockholders' equity.

The following table presents changes during the year in redeemable preferred stock of subsidiaries for Southern Company:

	Redeemable Preferred Stock of Subsidiaries (in millions)
Balance at December 31, 2013	$ 375
Issued	—
Redeemed	—
Balance at December 31, 2014	375

Issued	—
Redeemed	(262)
Other	5
Balance at December 31, 2015	118
Issued	—
Redeemed	—
Balance at December 31, 2016	$ 118

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7. COMMITMENTS
Fuel and Purchased Power Agreements
To supply a portion of the fuel requirements of the generating plants, the Southern Company system 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 2016, 2015, and 2014, the traditional electric operating companies and Southern Power incurred fuel expense of $4.4 billion, $4.8 billion, and $6.0 billion, respectively, the majority of which was purchased under long-term commitments. Southern Company expects that a substantial amount of the Southern Company system's future fuel needs will continue to be purchased under long-term commitments.
In addition, the Southern Company system has entered into various long-term commitments for the purchase of capacity and electricity, some of which are accounted for as operating leases or have been used by a third party to secure financing. Total capacity expense under PPAs accounted for as operating leases was $232 million, $227 million, and $198 million for 2016, 2015, and 2014, respectively.
Estimated total obligations under these commitments at December 31, 2016 were as follows:

	Operating Leases (*)	Other
	(in millions)	
2017	$242	$ 8
2018	246	7
2019	249	6
2020	246	5
2021	249	5
2022 and thereafter	1,041	43
Total	$2,273	$ 74

(*) A total of $197 million of biomass PPAs included under operating leases is contingent upon the counterparties meeting specified contract dates for commercial operation. Subsequent to December 31, 2016, the specified contract dates for commercial operation were extended from 2017 to 2019 and may change further as a result of regulatory action.

Pipeline Charges, Storage Capacity, and Gas Supply
Pipeline charges, storage capacity, and gas supply include charges recoverable through a natural gas cost recovery mechanism, or alternatively, billed to marketers selling retail natural gas, as well as demand charges associated with Southern Company Gas' wholesale gas services. The gas supply balance includes amounts for gas commodity purchase commitments associated with Southern Company Gas' gas marketing services of 33 million mmBtu at floating gas prices calculated using forward natural gas prices at December 31, 2016 and valued at $106 million. Southern Company Gas provides guarantees to certain gas suppliers for certain of its subsidiaries in support of payment obligations.
Expected future contractual obligations for pipeline charges, storage capacity, and gas supply that are not recognized on the balance sheets as of December 31, 2016 were as follows:

	Pipeline Charges, Storage Capacity, and Gas Supply
	(in millions)

2017	$ 822
2018	602
2019	447
2020	394
2021	352
2022 and thereafter	2,591
Total	$ 5,208

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Operating Leases
The Southern Company system has operating lease agreements with various terms and expiration dates. Total rent expense was $169 million, $130 million, and $118 million for 2016, 2015, and 2014, respectively. Southern Company includes any step rents, escalations, and lease concessions in its computation of minimum lease payments, which are recognized on a straight-line basis over the minimum lease term.
As of December 31, 2016, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Barges & Railcars	Other	Total
	(in millions)		
2017	$ 31	$ 121	$ 152
2018	19	115	134
2019	10	103	113
2020	10	90	100
2021	8	82	90
2022 and thereafter	11	1,184	1,195
Total	$ 89	$ 1,695	$ 1,784

For the traditional electric operating companies, a majority of the barge and railcar lease expenses are recoverable through fuel cost recovery provisions.
In addition to the above rental commitments, Alabama Power and Georgia Power have obligations upon expiration of certain railcar leases with respect to the residual value of the leased property. These leases have terms expiring through 2024 with maximum obligations under these leases of $44 million. At the termination of the leases, the lessee may renew the lease, exercise its purchase option, or the property can be sold to a third party. Alabama Power and Georgia Power expect that the fair market value of the leased property would substantially reduce or eliminate the payments under the residual value obligations.
Guarantees
In 2013, Georgia Power entered into an agreement that requires Georgia Power to guarantee certain payments of a gas supplier for Plant McIntosh for a period up to 15 years. The guarantee is expected to be terminated if certain events occur within one year of the initial gas deliveries in 2018. In the event the gas supplier defaults on payments, the maximum potential exposure under the guarantee is approximately $43 million.
As discussed above under "Operating Leases," Alabama Power and Georgia Power have entered into certain residual value guarantees.
8. COMMON STOCK
Stock Issued
In May and August 2016, Southern Company issued an aggregate of 50.8 million shares of common stock in underwritten offerings for an aggregate purchase price of approximately $2.5 billion. Of the 50.8 million shares, approximately 2.6 million were issued from treasury and the remainder were newly issued shares. The proceeds were used to fund a portion of the consideration for the Merger and related transaction costs, to fund a portion of the purchase price for the SNG investment and related transaction costs, and for other general corporate purposes.
During the fourth quarter 2016, Southern Company issued approximately 8.0 million shares of common stock through at-the-market issuances pursuant to sales agency agreements related to Southern Company's continuous equity offering program and received cash proceeds of approximately $381 million, net of $3 million in fees and commissions.
In addition, during 2016, Southern Company issued approximately 20 million shares of common stock primarily through employee equity compensation plans and received proceeds of approximately $874 million.
Shares Reserved

At December 31, 2016, a total of 94 million shares were reserved for issuance pursuant to the Southern Investment Plan, the Employee Savings Plan, the Outside Directors Stock Plan, and the Omnibus Incentive Compensation Plan (which includes stock

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options and performance share units as discussed below). Of the total 94 million shares reserved, there were 14 million shares of common stock remaining available for awards under the Omnibus Incentive Compensation Plan as of December 31, 2016.

Stock-Based Compensation

Stock-based compensation primarily in the form of performance share units may be granted through the Omnibus Incentive Compensation Plan to a large segment of Southern Company system employees ranging from line management to executives. As of December 31, 2016, there were 5,229 current and former employees participating in the stock option and performance share unit programs.

In conjunction with the Merger, stock-based compensation in the form of Southern Company restricted stock and performance share units was also granted to certain executives of Southern Company Gas through the Southern Company Omnibus Incentive Compensation Plan.

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.

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

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

Year Ended December 31	2014
Expected volatility	14.6%
Expected term (in years)	5
Interest rate	1.5%
Dividend yield	4.9%
Weighted average grant-date fair value	$2.20

Southern Company's activity in the stock option program for 2016 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2015	35,749,906	$ 40.96
Exercised	11,120,613	40.26
Cancelled	43,429	41.38
Outstanding at December 31, 2016	24,585,864	$ 41.28
Exercisable at December 31, 2016	21,133,320	$ 41.26

The number of stock options vested, and expected to vest in the future, as of December 31, 2016 was not significantly different from the number of stock options outstanding at December 31, 2016 as stated above. As of December 31, 2016, the weighted average remaining contractual term for the options outstanding and options exercisable was approximately six years and five years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $195 million and $168 million, respectively.

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For the years ended December 31, 2016, 2015, and 2014, total compensation cost for stock option awards recognized in income was $3 million, $6 million, and $27 million, respectively, with the related tax benefit also recognized in income of $1 million, $2 million, and $10 million, respectively. As of December 31, 2016, the total 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, 2016, 2015, and 2014 was $120 million, $48 million, and $125 million, respectively. The actual tax benefit for the tax deductions from stock option exercises totaled $46 million, $19 million, and $48 million for the years ended December 31, 2016, 2015, and 2014, respectively. Prior to the adoption of ASU 2016-09, the excess tax benefits related to the exercise of stock options were recognized in Southern Company's financial statements with a credit to equity. Upon the adoption of ASU 2016-09, beginning in 2016, all tax benefits related to the exercise of stock options are recognized in income.

Southern Company has a policy of issuing shares to satisfy share option exercises. Cash received from issuances related to option exercises under the share-based payment arrangements for the years ended December 31, 2016, 2015, and 2014 was $448 million, $154 million, and $400 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. 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. Southern 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, 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.

In determining the fair value of the TSR-based awards issued to employees, the expected volatility was based on the historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the performance period of the awards. The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of performance share award units granted:

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Year Ended December 31	2016	2015	2014
Expected volatility	15.0%	12.9%	12.6%
Expected term (in years)	3	3	3
Interest rate	0.8%	1.0%	0.6%
Annualized dividend rate(*)	N/A	N/A	$2.03
Weighted average grant-date fair value	$45.06	$46.38	$37.54

N/A - Not applicable

(*) Beginning in 2015, cash dividends paid on Southern Company's common stock are accumulated and payable in additional shares of Southern Company's common stock at the end of the three-year performance period and are embedded in the grant date fair value which equates to the grant date stock price.

The weighted average grant-date fair value of both EPS-based and ROE-based performance share units granted during 2016 and 2015 was $48.87 and $47.75, respectively.

Total unvested performance share units outstanding as of December 31, 2015 were 2,480,392. During 2016, 1,717,167 performance share units were granted, 937,121 performance share units were vested, and 35,899 performance share units were forfeited, resulting in 3,224,539 unvested performance share units outstanding at December 31, 2016. No shares were issued in January 2017 for the three-year performance and vesting period ended December 31, 2016.

For the years ended December 31, 2016, 2015, and 2014, total compensation cost for performance share units recognized in income was $96 million, $88 million, and $33 million, respectively, with the related tax benefit also recognized in income of $37 million, $34 million, and $13 million, respectively. As of December 31, 2016, $32 million of total unrecognized compensation cost related to performance share award units will be recognized over a weighted-average period of approximately 22 months.

Southern Company Gas Restricted Stock Awards

At the effective time of the Merger, each outstanding award of existing Southern Company Gas performance share units was converted into an award of Southern Company's restricted stock units (RSU). Under the terms of the RSU awards, the employees received Southern Company stock when they satisfy the requisite service period by being continuously employed through the original three-year vesting schedule of the award being replaced. Southern Company issued 742,461 RSUs with a grant-date fair value of $53.83, based on the closing stock price of Southern Company common stock on the date of the grant. As a portion of the fair value of the award related to pre-combination service, the grant date fair value was allocated to pre- or post-combination service and accounted for as Merger consideration or compensation cost, respectively. Approximately $13 million of the grant date fair value was allocated to Merger consideration.

As of December 31, 2016, total compensation cost and related tax benefit for RSUs recognized in income was $13 million and $4 million, respectively. As of December 31, 2016, $12 million of total unrecognized compensation cost related to RSUs is expected to be recognized over a weighted-average period of approximately 20 months.

Southern Company Gas Change in Control Awards

Southern Company awarded performance share units to certain Southern Company Gas employees who continued their employment with the Southern Company in lieu of certain change in control benefits the employee was entitled to receive following the Merger (change in control awards). Shares of Southern Company common stock and/or cash equal to the dollar value of the change in control benefit will vest and be issued one-third each year as long as the employee remains in service with Southern Company or its subsidiaries at each vest date. In addition to the change in control benefit, Southern Company common stock could be issued to the employees at the end of a performance period based on achievement of certain Southern Company common stock price metrics, as well performance goals established by the Compensation Committee of the Southern Company Board of Directors (achievement shares).

The change in control benefits are accounted for as a liability award with the fair value equal to the guaranteed dollar value of the change in control benefit. The grant-date fair value of the achievement portion of the award was determined using a Monte Carlo simulation model to estimate the number of achievement shares expected to vest based on the Southern Company common stock price. The expected payout is reevaluated annually with expense recognized to date increased or decreased proportionately based on the expected performance. The compensation expense ultimately recognized for the achievement shares will be based on the actual performance.

As of December 31, 2016, total compensation cost and related tax benefit for the change in control awards recognized in income was immaterial. As of December 31, 2016, approximately $20 million of total unrecognized compensation cost related to change in control awards is expected to be recognized over a weighted-average period of approximately 23 months.

NOTES (continued)
Southern Company and Subsidiary Companies 2016 Annual Report

Diluted Earnings Per Share

For Southern Company, the only difference in computing basic and diluted EPS is attributable to awards outstanding under the stock option and performance share plans. The effect of both stock options and performance share award units was determined using the treasury stock method. Shares used to compute diluted EPS were as follows:

	Average Common Stock Shares		
	2016	2015	2014
	(in millions)		
As reported shares	951	910	897
Effect of options and performance share award units	7	4	4
Diluted shares	958	914	901

Prior to the adoption of ASU 2016-09, the effect of options and performance share award units included the assumed impacts of any excess tax benefits from the exercise of all "in the money" outstanding share based awards. In accordance with the new guidance, no prior year information was adjusted. Stock options and performance share award units that were not included in the diluted EPS calculation because they were anti-dilutive were immaterial as of December 31, 2016 and 2015.

Common Stock Dividend Restrictions

The income of Southern Company is derived primarily from equity in earnings of its subsidiaries. At December 31, 2016, consolidated retained earnings included $7.0 billion of undistributed retained earnings of the subsidiaries.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), Alabama Power and Georgia Power maintain agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the companies' nuclear power plants. The Act provides funds up to $13.4 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. A 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 Alabama Power and Georgia Power, based on its ownership and buyback interests in all licensed reactors, is $255 million and $247 million, respectively, per incident, but not more than an aggregate of $38 million and $37 million, respectively, per company to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due no later than September 10, 2018. See Note 4 for additional information on joint ownership agreements.

Alabama Power and Georgia Power are members 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, both companies have 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 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. Alabama Power and Georgia Power each purchase limits based on the projected full cost of replacement power, subject to ownership limitations. Each facility has elected a 12-week deductible waiting period.

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

Under each of the NEIL policies, members are subject to assessments each year if losses exceed the accumulated funds available to the insurer. The maximum annual assessments for Alabama Power and Georgia Power as of December 31, 2016 under the NEIL policies would be $53 million and $82 million, respectively.

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 applicable 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 Alabama Power or Georgia Power, as applicable, and could have a material effect on Southern 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.

NOTES (continued)
Southern Company and Subsidiary Companies 2016 Annual Report

As of December 31, 2016, 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, 2016:	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[(a)(b)]	$338	$ 333	$ —	$ —	$671
Interest rate derivatives	—	14	—	—	14
Nuclear decommissioning trusts:[(c)]					
Domestic equity	589	73	—	—	662
Foreign equity	48	168	—	—	216
U.S. Treasury and government agency securities	—	92	—	—	92
Municipal bonds	—	73	—	—	73
Corporate bonds	22	310	—	—	332
Mortgage and asset backed securities	—	183	—	—	183
Private equity	—	—	—	20	20
Other	11	15	—	—	26
Cash equivalents	1,172	—	—	—	1,172
Other investments	9	—	1	—	10
Total	$2,189	$ 1,261	$ 1	$ 20	$3,471
Liabilities:					
Energy-related derivatives[(a)(b)]	$345	$ 285	$ —	$ —	$630
Interest rate derivatives	—	29	—	—	29
Foreign currency derivatives	—	58	—	—	58
Contingent consideration	—	—	18	—	18
Total	$345	$ 372	$ 18	$ —	$735

(a) Energy-related derivatives exclude $4 million associated with certain weather derivatives accounted for based on intrinsic value rather than fair value.
(b) Energy-related derivatives exclude cash collateral of $62 million.
(c) Includes the investment securities pledged to creditors and collateral received, and excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases and the lending pool. See Note 1 under "Nuclear Decommissioning" for additional information.

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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				
	Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs	Net Asset Value as a Practical Expedient	
As of December 31, 2015:	(Level 1)	(Level 2)	(Level 3)	(NAV)	Total
	(in millions)				
Assets:					
Energy-related derivatives	$—	$ 7	$ —	$ —	$7
Interest rate derivatives	—	22	—	—	22
Nuclear decommissioning trusts:(*)					
Domestic equity	541	69	—	—	610
Foreign equity	47	160	—	—	207
U.S. Treasury and government agency securities	—	152	—	—	152
Municipal bonds	—	64	—	—	64
Corporate bonds	11	278	—	—	289
Mortgage and asset backed securities	—	145	—	—	145
Private equity	—	—	—	17	17
Other	16	9	—	—	25
Cash equivalents	790	—	—	—	790
Other investments	9	—	1	—	10
Total	$1,414	$ 906	$ 1	$ 17	$2,338
Liabilities:					
Energy-related derivatives	$—	$ 220	$ —	$ —	$220
Interest rate derivatives	—	30	—	—	30
Total	$—	$ 250	$ —	$ —	$250

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

Valuation Methodologies

The energy-related derivatives primarily consist of exchange-traded and 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 reflects 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 fair value of cross-currency swaps reflects the net present value of expected payments and receipts under the swap agreement based on the market's expectation of future foreign currency exchange rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk, and discount rates. The interest rate derivatives and cross-currency swaps are categorized as Level 2 under Fair Value Measurements as these inputs are based on observable data and valuations of similar instruments. See Note 11 for additional information on how these derivatives are used.

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. For fair value measurements of the investments within the nuclear decommissioning trusts, external pricing vendors are designated for each asset class with each security specifically assigned a primary pricing source. For investments held within commingled funds, fair value is determined at the end of each business day through the net asset value, which is established by obtaining the underlying securities' individual prices from the primary pricing source. A market price secured from the primary source vendor is then evaluated by management in its valuation of the assets within the trusts. As a general approach, fixed income market pricing vendors gather market data (including indices and market research reports) and integrate relative credit information, observed market movements, and sector news into proprietary pricing models, pricing systems, and mathematical tools. Dealer quotes and other market information, including live trading levels and pricing analysts' judgments, are also obtained when available. See Note 1 under "Nuclear Decommissioning" for additional information.

Southern Power has contingent payment obligations related to certain acquisitions whereby Southern Power is obligated to pay generation-based payments to the seller over a 10-year period beginning at the commercial operation date. The obligation is measured at fair value using significant inputs such as forecasted facility generation in MW-hours, a fixed dollar amount per MW-hour, and a discount rate, and is evaluated periodically. The fair value of contingent consideration reflects the net present value of expected payments and any change arising from forecasted generation is expected to be immaterial.

"Other investments" include investments that are not traded in the open market. The fair value of these investments have been determined based on market factors including comparable multiples and the expectations regarding cash flows and business plan executions.

As of December 31, 2016 and 2015, the fair value measurements of private equity investments held in the nuclear decommissioning trust 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, 2016	$ 20	$ 25	Not Applicable	Not Applicable
As of December 31, 2015	$ 17	$ 28	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 are expected to occur at various times over the next 10 years.

As of December 31, 2016 and 2015, 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:		
2016	$45,080	$46,286
2015	$27,216	$27,913

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 Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, Southern Company Gas, and Nicor Gas.

11. DERIVATIVES

The Southern Company system is exposed to market risks, including commodity price risk, interest rate risk, weather risk, and occasionally foreign currency exchange rate risk. To manage the volatility attributable to these exposures, each company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to each company's policies in areas such as counterparty exposure and risk management practices. Each 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 net 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. The cash impacts of settled foreign currency derivatives are classified as operating or financing activities to correspond with classification of the hedged interest or principal, respectively. See Note 1 under "Financial Instruments" for additional information.

Energy-Related Derivatives

Southern Company and certain subsidiaries enter into energy-related derivatives to hedge exposures to electricity, natural gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the traditional electric operating companies and natural gas distribution utilities have limited exposure to market volatility in energy-related commodity prices. Each of the traditional electric operating companies and certain of the natural gas distribution utilities manage fuel-hedging programs, implemented per the guidelines of their respective state PSCs or other applicable state regulatory agencies, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility. The traditional electric operating companies (with respect to wholesale generating capacity) and Southern Power have limited exposure to market volatility in energy-related commodity prices because their long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, the traditional electric operating companies and Southern Power may be exposed to market volatility in energy-related commodity prices to the extent any uncontracted capacity is used to sell electricity.

Southern Company Gas uses storage and transportation capacity contracts to manage market price risks. Southern Company Gas purchases natural gas for storage when the current market price paid to buy and transport natural gas plus the cost to store and finance the natural gas is less than the market price Southern Company Gas will receive in the future, resulting in a positive net adjusted operating margin. Southern Company Gas uses New York Mercantile Exchange (NYMEX) futures and over-the-counter (OTC) contracts to sell natural gas at that future price to substantially protect the adjusted operating margin ultimately realized when the stored natural gas is sold. Southern Company Gas also enters into transactions to secure transportation capacity between delivery points in order to serve its customers and various markets. Southern Company Gas uses NYMEX futures and OTC contracts to capture the price differential between the locations served by the capacity in order to substantially protect the adjusted operating margin ultimately realized when natural gas is physically flowed between the delivery points. These contracts generally meet the definition of derivatives, but are not designated as hedges for accounting purposes.

Southern Company Gas also enters into weather derivative contracts as economic hedges of adjusted operating margins in the event of warmer-than-normal weather. Exchange-traded options are carried at fair value, with changes reflected in operating revenues. Non-exchange-traded options are accounted for using the intrinsic value method. Changes in the intrinsic value for non-exchange-traded contracts are reflected in the statements of income.

Energy-related derivative contracts are accounted for under one of three methods:

- Regulatory Hedges – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the traditional electric operating companies' and natural gas distribution utilities' 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 respective fuel cost recovery clauses.
- Cash Flow Hedges – Gains and losses on energy-related derivatives designated as cash flow hedges (which are mainly used to hedge anticipated purchases and sales) are initially deferred in OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- Not Designated – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric and natural gas industries. 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, 2016, the net volume of energy-related derivative contracts for natural gas positions totaled 500 million mmBtu for the Southern Company system, with the longest hedge date of 2020 over which the respective entity is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest non-hedge date of 2022 for derivatives not designated as hedges.

In addition to the volumes discussed above, the traditional electric operating companies and Southern Power enter into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The maximum expected volume of natural gas subject to such a feature is 9 million mmBtu.

For cash flow hedges, the amounts expected to be reclassified from accumulated OCI to earnings for the next 12-month period ending December 31, 2017 are $17 million for Southern Company.

NOTES (continued)
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Interest Rate Derivatives
Southern Company and certain subsidiaries may also enter into interest rate derivatives to hedge exposure to changes in interest rates. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings, with any ineffectiveness recorded directly to earnings. Derivatives related to existing fixed rate securities are accounted for as fair value hedges, where the derivatives' fair value gains or losses and hedged items' fair value gains or losses are both recorded directly to earnings, providing an offset, with any difference representing ineffectiveness. Fair value gains or losses on derivatives that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred. At December 31, 2016, the following interest rate derivatives were outstanding:

	Notional Amount (in millions)	Interest Rate Received	Weighted Average Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2016 (in millions)
Cash Flow Hedges of Forecasted Debt					
	$ 80	3-month LIBOR	2.32%	December 2026	$ —
Cash Flow Hedges of Existing Debt					
	900	1-month LIBOR	0.79%	March 2018	3
Fair Value Hedges of Existing Debt					
	250	1.30%	3-month LIBOR + 0.17%	August 2017	—
	250	5.40%	3-month LIBOR + 4.02%	June 2018	—
	500	1.95%	3-month LIBOR + 0.76%	December 2018	(2)
	200	4.25%	3-month LIBOR + 2.46%	December 2019	1
	300	2.75%	3-month LIBOR + 0.92%	June 2020	1
	1,500	2.35%	1-month LIBOR + 0.87%	July 2021	(18)
Derivatives not Designated as Hedges					
	47 (a,b)	3-month LIBOR	2.21%	January 2017 (c)	1
Total	$ 4,027				$ (14)

(a) Swaption at RE Roserock LLC. See Note 12 for additional information.
(b) Amortizing notional amount.
(c) Represents the mandatory settlement date. Settlement amount was based on a 15-year amortizing swap.

The estimated pre-tax gains (losses) expected to be reclassified from accumulated OCI to interest expense for the next 12-month period ending December 31, 2017 total $(21) million. Deferred gains and losses are expected to be amortized into earnings through 2046.

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Foreign Currency Derivatives

Southern Company and certain subsidiaries may also enter into foreign currency derivatives to hedge exposure to changes in foreign currency exchange rates, such as that arising from the issuance of debt denominated in a currency other than U.S. dollars. Derivatives related to 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 that the hedged transactions affect earnings, including foreign currency gains or losses arising from changes in the U.S. currency exchange rates. Any ineffectiveness is recorded directly to earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness.

At December 31, 2016, the following foreign currency derivatives were outstanding:

	Pay Notional	Pay Rate	Receive Notional	Receive Rate	Hedge Maturity Date	Fair Value Gain (Loss) at December 31, 2016
	(in millions)		(in millions)			(in millions)
Cash Flow Hedges of Existing Debt						
	$ 677	2.95%	€600	1.00%	June 2022	$ (34)
	564	3.78%	500	1.85%	June 2026	(24)
Total	$ 1,241		€1,100			$ (58)

The estimated pre-tax gains (losses) that will be reclassified from accumulated OCI to earnings for the next 12-month period ending December 31, 2017 total $(25) million.

Derivative Financial Statement Presentation and Amounts

Southern Company and its subsidiaries enter into derivative contracts that may contain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Southern Company and certain subsidiaries also utilize master netting agreements to mitigate exposure to counterparty credit risk. These agreements may contain provisions that permit netting across product lines and against cash collateral.

At December 31, 2016, fair value amounts of derivative assets and liabilities on the balance sheets are presented net to the extent that there are netting arrangements or similar agreements with the counterparties. At December 31, 2015, the fair value amounts of derivative instruments were presented gross on the balance sheets.

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At December 31, 2016 and 2015, the fair value of energy-related derivatives, interest rate derivatives, and foreign currency derivatives was reflected in the balance sheets as follows:

Derivative Category and Balance Sheet Location	2016 Assets	2016 Liabilities	2015 Assets	2015 Liabilities
	(in millions)			
Derivatives designated as hedging instruments for regulatory purposes				
Energy-related derivatives:				
Other current assets/Liabilities from risk management activities, net of collateral	$73	$ 27	$3	$ 130
Other deferred charges and assets/Other deferred credits and liabilities	25	33	—	87
Total derivatives designated as hedging instruments for regulatory purposes	$98	$ 60	$3	$ 217
Derivatives designated as hedging instruments in cash flow and fair value hedges				
Energy-related derivatives:				
Other current assets/Liabilities from risk management activities, net of collateral	$23	$ 7	$3	$ 2
Interest rate derivatives:				
Other current assets/Liabilities from risk management activities, net of collateral	12	1	19	23
Other deferred charges and assets/Other deferred credits and liabilities	1	28	—	7
Foreign currency derivatives:				
Other current assets/Liabilities from risk management activities, net of collateral	—	25	—	—
Other deferred charges and assets/Other deferred credits and liabilities	—	33	—	—
Total derivatives designated as hedging instruments in cash flow and fair value hedges	$36	$ 94	$22	$ 32
Derivatives not designated as hedging instruments				
Energy-related derivatives:				
Other current assets/Liabilities from risk management activities, net of collateral	$489	$ 483	$1	$ 1
Other deferred charges and assets/Other deferred credits and liabilities	66	81	—	—
Interest rate derivatives:				
Other current assets/Liabilities from risk management activities, net of collateral	1	—	3	—
Total derivatives not designated as hedging instruments	$556	$ 564	$4	$ 1
Gross amounts recognized	$690	$ 718	$29	$ 250
Gross amounts offset[(a)]	$(462)	$ (524)	$(15)	$ (15)
Net amounts recognized in the Balance Sheets[(b)]	$228	$ 194	$14	$ 235

(a) Gross amounts offset include cash collateral held on deposit in broker margin accounts of $62 million as of December 31, 2016.

(b) At December 31, 2015, the fair value amounts for derivative contracts subject to netting arrangements were presented gross on the balance sheet.

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At December 31, 2016 and 2015, the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivatives designated as regulatory hedging instruments and deferred were as follows:

Derivative Category	Unrealized Losses Balance Sheet Location	2016	2015	Unrealized Gains Balance Sheet Location	2016	2015
		(in millions)			(in millions)	
Energy-related derivatives:[a]	Other regulatory assets, current	$(16)	$(130)	Other regulatory liabilities, current	$ 56	$ 3
	Other regulatory assets, deferred	(19)	(87)	Other regulatory liabilities, deferred	12	—
Total energy-related derivative gains (losses)[b]		$(35)	$(217)		$ 68	$ 3

(a) At December 31, 2016, the unrealized gains and losses for derivative contracts subject to netting arrangements were presented net on the balance sheet. At December 31, 2015, the unrealized gains and losses for derivative contracts were presented gross on the balance sheet.

(b) Fair value gains and losses recorded in regulatory assets and liabilities include cash collateral held on deposit in broker margin accounts of $8 million as of December 31, 2016.

For the years ended December 31, 2016, 2015, and 2014, the pre-tax effects of energy-related derivatives, interest rate derivatives, and foreign currency derivatives designated as cash flow hedging instruments on the statements of income were as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)			Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
	Amount				Amount		
Derivative Category	2016	2015	2014	Statements of Income Location	2016	2015	2014
	(in millions)				(in millions)		
Energy-related derivatives	$ 18	$ —	$ —	Depreciation and amortization	$ 2	$ —	$ —
				Cost of natural gas	(1)	—	—
Interest rate derivatives	(180)	(22)	(16)	Interest expense, net of amounts capitalized	(18)	(9)	(8)
Foreign currency derivatives	(58)	—	—	Interest expense, net of amounts capitalized	(13)	—	—
				Other income (expense), net[*]	(82)	—	—
Total	$ (220)	$ (22)	$ (16)		$(112)	$(9)	$(8)

(*) The reclassification from accumulated OCI into other income (expense), net completely offsets currency gains and losses arising from changes in the U.S. currency exchange rates used to record the euro-denominated notes.

For the years ended December 31, 2016, 2015, and 2014, the pre-tax effects of interest rate derivatives designated as fair value hedging instruments were as follows:

Derivatives in Fair Value Hedging Relationships		Gain (Loss)		
Derivative Category	Statements of Income Location	2016	2015	2014
		(in millions)		
Interest rate derivatives:	Interest expense, net of amounts capitalized	$(21)	$ 2	$(3)

For all years presented, the pre-tax effects of interest rate derivatives designated as fair value hedging instruments were offset by changes to the carrying value of long-term debt.

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

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For the years ended December 31, 2016, 2015, and 2014, the pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of income were as follows:

Derivatives Not Designated as Hedging Instruments		Unrealized Gain (Loss) Recognized in Income		
		Amount		
Derivative Category	Statements of Income Location	2016	2015	2014
		(in millions)		
Energy-related derivatives	Wholesale electric revenues	$2	$(5)	$6
	Fuel	—	3	(4)
	Natural gas revenues(*)	33	—	—
	Cost of natural gas	3	—	—
Total		$38	$(2)	$2

(*) Excludes gains (losses) recorded in cost of natural gas associated with weather derivatives of $6 million for the period ended December 31, 2016.

For the years ended December 31, 2016, 2015, and 2014, the pre-tax effects of interest rate derivatives not designated as hedging instruments were immaterial.

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 Southern Company subsidiaries. At December 31, 2016, the fair value of derivative liabilities with contingent features was immaterial. The maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were immaterial 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.

Southern Company maintains accounts with brokers or the clearing houses of certain exchanges to facilitate financial derivative transactions. Based on the value of the positions in these accounts and the associated margin requirements, Southern Company may be required to deposit cash into these accounts. At December 31, 2016, cash collateral held on deposit in broker margin accounts was $62 million.

Southern Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. Southern 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. Southern Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate Southern Company's exposure to counterparty credit risk. Southern Company may require counterparties to pledge additional collateral when deemed necessary. Therefore, Southern Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

12. ACQUISITIONS

Southern Company

Merger with Southern Company Gas

Southern Company Gas is an energy services holding company whose primary business is the distribution of natural gas through the natural gas distribution utilities. On July 1, 2016, Southern Company completed the Merger for a total purchase price of approximately $8.0 billion and Southern Company Gas became a wholly-owned, direct subsidiary of Southern Company.

The Merger was accounted for using the acquisition method of accounting with the assets acquired and liabilities assumed recognized at fair value as of the acquisition date. The following table presents the purchase price allocation:

Southern Company Gas Purchase Price	December 31, 2016
	(in millions)
Current assets	$ 1,557
Property, plant, and equipment	10,108
Goodwill	5,967
Intangible assets	400
Regulatory assets	1,118
Other assets	229
Current liabilities	(2,201)
Other liabilities	(4,742)
Long-term debt	(4,261)
Noncontrolling interests	(174)
Total purchase price	$ 8,001

The excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed of $6.0 billion is recognized as goodwill, which is primarily attributable to positioning the Southern Company system to provide natural gas infrastructure to meet customers' growing energy needs and to compete for growth across the energy value chain. Southern Company anticipates that much of the value assigned to goodwill will not be deductible for tax purposes.

The valuation of identifiable intangible assets included customer relationships, trade names, and storage and transportation contracts with estimated lives of one to 28 years. The estimated fair value measurements of identifiable intangible assets were primarily based on significant unobservable inputs (Level 3).

The results of operations for Southern Company Gas have been included in the consolidated financial statements from the date of acquisition and consist of operating revenues of $1.7 billion and net income of $114 million.

The following summarized unaudited pro forma consolidated statement of earnings information assumes that the acquisition of Southern Company Gas was completed on January 1, 2015. The summarized unaudited pro forma consolidated statement of earnings information includes adjustments for (i) intercompany sales, (ii) amortization of intangible assets, (iii) adjustments to interest expense to reflect current interest rates on Southern Company Gas debt and additional interest expense associated with borrowings by Southern Company to fund the Merger, and (iv) the elimination of nonrecurring expenses associated with the Merger.

	2016	2015
Operating revenues (in millions)	$21,791	$21,430
Net income attributable to Southern Company (in millions)	$2,591	$2,665
Basic EPS	$2.70	$2.85
Diluted EPS	$2.68	$2.84

These unaudited pro forma results are for comparative purposes only and may not be indicative of the results that would have occurred had this acquisition been completed on January 1, 2015 or the results that would be attained in the future.

During 2016 and 2015, Southern Company recorded in its statements of income costs associated with the Merger of approximately $111 million and $41 million, respectively, of which $80 million and $27 million is included in operating expenses and $31 million and $14 million is included in other income and (expense), respectively. These costs include external transaction costs for financing, legal, and consulting services, as well as customer rate credits

and additional compensation-related expenses.
Acquisition of PowerSecure
On May 9, 2016, Southern Company acquired all of the outstanding stock of PowerSecure, a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure, for $18.75 per common share in cash, resulting in an aggregate purchase price of $429 million. As a result, PowerSecure became a wholly-owned subsidiary of Southern Company.

NOTES (continued)
Southern Company and Subsidiary Companies 2016 Annual Report

The acquisition of PowerSecure was accounted for using the acquisition method of accounting with the assets acquired and liabilities assumed recognized at fair value as of the acquisition date. The allocation of the purchase price is as follows:

PowerSecure Purchase Price	December 31, 2016
	(in millions)
Current assets	$ 172
Property, plant, and equipment	46
Intangible assets	101
Goodwill	282
Other assets	4
Current liabilities	(114)
Long-term debt, including current portion	(48)
Deferred credits and other liabilities	(14)
Total purchase price	$ 429

The excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed of $282 million was recognized as goodwill, which is primarily attributable to expected business expansion opportunities for PowerSecure. Southern Company anticipates that the majority of the value assigned to goodwill will not be deductible for tax purposes.

The valuation of identifiable intangible assets included customer relationships, trade names, patents, backlog, and software with estimated lives of one to 26 years. The estimated fair value measurements of identifiable intangible assets were primarily based on significant unobservable inputs (Level 3).

The results of operations for PowerSecure have been included in the consolidated financial statements from the date of acquisition and are immaterial to the consolidated financial results of Southern Company. Pro forma results of operations have not been presented for the acquisition because the effects of the acquisition were immaterial to Southern Company's consolidated financial results for all periods presented.

Alliance with Bloom Energy Corporation

On October 24, 2016, a subsidiary of Southern Company acquired from an affiliate of Bloom Energy Corporation (Bloom) all of the equity interests of 2016 ESA HoldCo, LLC and its subsidiary, 2016 ESA Project Company, LLC. 2016 ESA Project Company, LLC expects to acquire 50 MWs of Bloom fuel cell systems to serve commercial and industrial customers under long-term PPAs. In connection with this transaction, PowerSecure and Bloom agreed to pursue a strategic alliance to develop technology for behind-the-meter energy solutions.

Investment in Southern Natural Gas

On July 10, 2016, Southern Company and Kinder Morgan, Inc. entered into a definitive agreement for Southern Company to acquire a 50% equity interest in SNG, which is the owner of a 7,000-mile pipeline system connecting natural gas supply basins in Texas, Louisiana, Mississippi, and Alabama to markets in Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina, and Tennessee. On August 31, 2016, Southern Company assigned its rights and obligations under the definitive agreement to a wholly-owned, indirect subsidiary of Southern Company Gas. On September 1, 2016, Southern Company Gas completed the acquisition for a purchase price of approximately $1.4 billion. The investment in SNG is accounted for using the equity method.

Acquisition of Remaining Interest in SouthStar

SouthStar is a retail natural gas marketer and markets natural gas to residential, commercial, and industrial customers, primarily in Georgia and Illinois. Southern Company Gas previously had an 85% ownership interest in SouthStar, with Piedmont owning the remaining 15%. In October 2016, Southern Company Gas purchased Piedmont's 15% interest in SouthStar for $160 million.

Southern Power

During 2016 and 2015, in accordance with its overall growth strategy, Southern Power or one of its wholly-owned subsidiaries, Southern Renewable Partnerships, LLC (SRP) or Southern Renewable Energy, Inc. (SRE), acquired or contracted to acquire the projects discussed below. Also, on March 29, 2016, Southern Power acquired an additional 15% interest in Desert Stateline, 51% of which was initially acquired in August 2015. As a result, Southern Power and the class B member are now entitled to 66% and

34%, respectively, of all cash distributions from Desert Stateline. In addition, Southern Power will continue to be entitled to substantially all of the federal tax benefits with respect to the transaction.

NOTES (continued)
Southern Company and Subsidiary Companies 2016 Annual Report

The following table presents Southern Power's acquisitions during and subsequent to the year ended December 31, 2016.

Project Facility	Resource	Seller; Acquisition Date	Approximate Nameplate Capacity (MW)	Location	Southern Power Percentage Ownership		Actual/Expected COD	PPA Contract Period
Acquisitions During the Year Ended December 31, 2016								
Boulder 1	Solar	SunPower Corp. November 16, 2016	100	Clark County, NV	51	% (a)	December 2016	20 years
Calipatria	Solar	Solar Frontier Americas Holding LLC February 11, 2016	20	Imperial County, CA	90	% (b)	February 2016	20 years
East Pecos	Solar	First Solar, Inc. March 4, 2016	120	Pecos County, TX	100	%	March 2017	15 years
Grant Plains	Wind	Apex Clean Energy Holdings, LLC August 26, 2016	147	Grant County, OK	100	%	December 2016	20 years and 12 years (c)
Grant Wind	Wind	Apex Clean Energy Holdings, LLC April 7, 2016	151	Grant County, OK	100	%	April 2016	20 years
Henrietta	Solar	SunPower Corp. July 1, 2016	102	Kings County, CA	51	% (a)	July 2016	20 years
Lamesa	Solar	RES America Developments Inc. July 1, 2016	102	Dawson County, TX	100	%	Second quarter 2017	15 years
Mankato(d)	Natural Gas	Calpine Corporation October 26, 2016	375	Mankato, MN	100	%	N/A (e)	10 years
Passadumkeag	Wind	Quantum Utility Generation, LLC June 30, 2016	42	Penobscot County, ME	100	%	July 2016	15 years
Rutherford	Solar	Cypress Creek Renewables, LLC July 1, 2016	74	Rutherford County, NC	90	% (b)	December 2016	15 years
Salt Fork	Wind	EDF Renewable Energy, Inc. December 1, 2016	174	Donley and Gray Counties, TX	100	%	December 2016	14 years and 12 years
Tyler Bluff	Wind	EDF Renewable Energy, Inc. December 21, 2016	125	Cooke County, TX	100	%	December 2016	12 years
Wake Wind	Wind	Invenergy Wind	257	Floyd and Crosby	90.1	% (f)	October 2016	12 years

		Global LLC October 26, 2016		Counties, TX				
Acquisitions Subsequent to December 31, 2016								
Bethel	Wind	Invenergy Wind Global LLC January 6, 2017	276	Castro County, TX	100	%	January 2017	12 years

NOTES (continued)
Southern Company and Subsidiary Companies 2016 Annual Report

(a) Southern Power owns 100% of the class A membership interests and a wholly-owned subsidiary of the seller owns 100% of the class B membership interests. Southern Power and the class B member are entitled to 51% and 49%, respectively, of all cash distributions from the project. In addition, Southern Power is entitled to substantially all of the federal tax benefits with respect to the transaction.
(b) Southern Power owns 90%, with the minority owner, Turner Renewable Energy, LLC (TRE), owning 10%.
(c) In addition to the 20-year and 12-year PPAs, the facility has a 10-year contract with Allianz Risk Transfer (Bermuda) Ltd.
(d) Under the terms of the remaining 10-year PPA and the 20-year expansion PPA, approximately $408 million of assets, primarily related to property, plant, and equipment, are subject to lien at December 31, 2016.
(e) The acquisition included a fully operational 375-MW natural gas-fired combined-cycle facility.
(f) Southern Power owns 90.1%, with the minority owner, Invenergy Wind Global LLC, owning 9.9%.

Acquisitions During the Year Ended December 31, 2016

Southern Power's aggregate purchase price for acquisitions during the year ended December 31, 2016 was approximately $2.3 billion. Including the minority owner TRE's 10% ownership interest in Calipatria and Rutherford, SunPower Corp's 49% ownership interest in Boulder 1 and Henrietta, along with the assumption of $217 million in construction debt (non-recourse to Southern Power), and Invenergy Wind Global LLC's 9.9% ownership interest in Wake Wind, the total aggregate purchase price is approximately $2.6 billion for the project facilities acquired during the year ended December 31, 2016. The allocations of the purchase price to individual assets have not been finalized, except for Calipatria, East Pecos, Lamesa, and Rutherford, which were finalized with no changes to amounts originally reported. The fair values of the assets and liabilities acquired through the business combinations were recorded as follows:

	2016 (in millions)
CWIP	$ 2,354
Property, plant, and equipment	302
Intangible assets [(a)]	128
Other assets	52
Accounts payable	(16)
Debt	(217)
Total purchase price	$ 2,603
Funded by:	
Southern Power [(b)(c)]	$ 2,345
Noncontrolling interests [(d)(e)]	258
Total purchase price	$ 2,603

(a) Intangible assets consist of acquired PPAs that will be amortized over 10 and 20-year terms. The estimated amortization for future periods is approximately $9 million per year.
(b) At December 31, 2016, $461 million is included in acquisitions payable on the balance sheets.
(c) Includes approximately $281 million of contingent consideration, of which $67 million remains payable at December 31, 2016.
(d) Includes approximately $51 million of non-cash contributions recorded as capital contributions from noncontrolling interests in the statements of stockholders' equity.
(e) Includes approximately $142 million of contingent consideration, all of which had been paid at December 31, 2016 by the noncontrolling interests.

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NOTES (continued)
Southern Company and Subsidiary Companies 2016 Annual Report

The following table presents Southern Power's acquisitions for the year ended December 31, 2015. During the year ended December 31, 2016, the fair values of assets and liabilities acquired for all projects listed below were finalized with no changes to amounts originally reported.

Project Facility	Resource	Seller; Acquisition Date	Approximate Nameplate Capacity (MW)	Location	Southern Power Percentage Ownership			Actual COD	PPA Contract Period
Acquisitions for the Year Ended December 31, 2015									
Desert Stateline	Solar	First Solar Inc. August 31, 2015	299[(a)]	San Bernardino County, CA	51	%	(b)	From December 2015 to July 2016	20 years
Garland and Garland A	Solar	Recurrent Energy, LLC December 17, 2015	205	Kern County, CA	51	%	(b)	October and August 2016	15 years and 20 years
Kay Wind	Wind	Apex Clean Energy Holdings, LLC December 11, 2015	299	Kay County, OK	100	%		December 2015	20 years
Lost Hills Blackwell	Solar	First Solar Inc. April 15, 2015	33	Kern County, CA	51	%	(b)	April 2015	29 years
Morelos	Solar	Solar Frontier Americas Holding, LLC October 22, 2015	15	Kern County, CA	90	%	(c)	November 2015	20 years
North Star	Solar	First Solar Inc. April 30, 2015	61	Fresno County, CA	51	%	(b)	June 2015	20 years
Roserock	Solar	Recurrent Energy, LLC November 23, 2015	160	Pecos County, TX	51	%	(b)	November 2016	20 years
Tranquillity	Solar	Recurrent Energy, LLC August 28, 2015	205	Fresno County, CA	51	%	(b)	July 2016	18 years

(a) The facility has a total of 299 MWs, of which 110 MWs were placed in service in the fourth quarter 2015 and the remainder by July 2016.

(b) Southern Power owns 100% of the class A membership interests and a wholly-owned subsidiary of the seller owns 100% of the class B membership interests. Southern Power and the class B member are entitled to 51% and 49%, respectively, of all cash distributions from the project. In addition, Southern Power is entitled to substantially all of the federal tax benefits with respect to the transaction.

(c) Southern Power owns 90%, with the minority owner, TRE, owning 10%.

Acquisitions During the Year Ended December 31, 2015

Southern Power's aggregate purchase price for the project facilities acquired during the year ended December 31, 2015 was approximately $1.4 billion. Including the minority owner TRE's 10% ownership interest in Morelos, First Solar Inc.'s 49% ownership interest in Desert Stateline, Lost Hills Blackwell, and North Star, and Recurrent Energy, LLC's 49% ownership interest in Garland, Garland A, Roserock, and Tranquillity, the total aggregate purchase price was approximately $1.9 billion for the project facilities acquired during the year ended December 31, 2015.

NOTES (continued)
Southern Company and Subsidiary Companies 2016 Annual Report

The fair values of the assets and liabilities acquired through the business combinations were recorded as follows:

	2015
	(in millions)
CWIP	$ 1,367
Property, plant, and equipment	315
Intangible assets [(a)]	274
Other assets	64
Accounts payable	(89)
Total purchase price	$ 1,931
Funded by:	
Southern Power [(b)]	$ 1,440
Noncontrolling interests [(c)] [(d)]	491
Total purchase price	$ 1,931

(a) Intangible assets consist of acquired PPAs that will be amortized over 20-year terms. The estimated amortization for future periods is approximately $14 million per year.

(b) Includes approximately $195 million of contingent consideration, all of which has been paid at December 31, 2016.

(c) Includes approximately $227 million of non-cash contributions recorded as capital contributions from noncontrolling interests in the statements of stockholders' equity.

(d) Includes approximately $76 million of contingent consideration, all of which had been paid at December 31, 2016 by the noncontrolling interests.

Construction Projects

Construction Projects Completed

During 2016, in accordance with Southern Power's overall growth strategy, Southern Power completed construction of, and placed in service, the projects set forth in the table below. Total costs of construction incurred for these projects were $3.2 billion.

Solar Facility	Seller	Approximate Nameplate Capacity (MW)	Location	Actual COD	PPA Contract Period
Butler	CERSM, LLC and Community Energy, Inc.	103	Taylor County, GA	December 2016	30 years [(a)]
Butler Solar Farm	Strata Solar Development, LLC	22	Taylor County, GA	February 2016	20 years [(a)]
Desert Stateline	First Solar Development, LLC	299[(b)]	San Bernardino County, CA	From December 2015 to July 2016	20 years
Garland	Recurrent Energy, LLC	185	Kern County, CA	October 2016	15 years
Garland A	Recurrent Energy, LLC	20	Kern County, CA	August 2016	20 years
Pawpaw	Longview Solar, LLC	30	Taylor County, GA	March 2016	30 years
Roserock [(c)]	Recurrent Energy, LLC	160	Pecos County, TX	November 2016	20 years
Sandhills	N/A	146	Taylor County, GA	October 2016	25 years
Tranquillity	Recurrent Energy, LLC	205	Fresno County, CA	July 2016	18 years

(a) Affiliate PPA approved by the FERC.

(b) The facility has a total of 299 MWs, of which 110 MWs were placed in service in the fourth quarter 2015 and the remainder by July 2016.

(c) Prior to placing the Roserock facility in service, certain solar panels were damaged. While the facility is currently generating energy as expected, Southern Power is pursuing remedies under its insurance policies and other contracts to repair or replace these solar panels.

Construction Projects in Progress

At December 31, 2016, Southern Power continued construction of the East Pecos and Lamesa solar facilities that were acquired in 2016. In addition, as part of Southern Power's acquisition of Mankato in 2016, Southern Power commenced construction of an additional 345-MW expansion, which is fully contracted under a new 20-year PPA. Total aggregate construction costs, excluding the acquisition costs, are expected to be $530 million to $590 million for East Pecos, Lamesa, and Mankato. At December 31,

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2016, the construction costs totaled $386 million and are included in CWIP. The ultimate outcome of these matters cannot be determined at this time.

The following table presents Southern Power's construction projects in progress as of December 31, 2016:

Project Facility	Resource	Approximate Nameplate Capacity (MW)	Location	Actual/Expected COD	PPA Contract Period
East Pecos	Solar	120	Pecos County, TX	March 2017	15 years
Lamesa	Solar	102	Dawson County, TX	Second quarter 2017	15 years
Mankato	Natural Gas	345	Mankato, MN	Second quarter 2019	20 years

Development Projects

In December 2016, as part of Southern Power's renewable development strategy, SRP entered into a joint development agreement with Renewable Energy Systems Americas, Inc. to develop and construct approximately 3,000 MWs across 10 wind projects expected to be placed in service between 2018 and 2020. Also in December 2016, Southern Power signed agreements and made payments to purchase wind turbine equipment from Siemens Wind Power, Inc. and Vestas-American Wind Technology, Inc. to be used for construction of the facilities. Once these wind projects reach commercial operations, they are expected to qualify for 100% PTCs. The ultimate outcome of these matters cannot be determined at this time.

13. SEGMENT AND RELATED INFORMATION

The primary business of the Southern Company system is electricity sales by the traditional electric operating companies and Southern Power and, as a result of closing the Merger, the distribution of natural gas by Southern Company Gas. The four traditional electric operating companies – Alabama Power, Georgia Power, Gulf Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. Southern Power constructs, acquires, owns, and manages power generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. Southern Company Gas distributes natural gas through the natural gas distribution utilities in seven states and is involved in several other complementary businesses including gas marketing services, wholesale gas services, and gas midstream operations.

Southern Company's reportable business segments are the sale of electricity by the four traditional electric operating companies, the sale of electricity in the competitive wholesale market by Southern Power, and the sale of natural gas and other complementary products and services by Southern Company Gas. Revenues from sales by Southern Power to the traditional electric operating companies were $419 million, $417 million, and $383 million in 2016, 2015, and 2014, respectively. The "All Other" column includes the Southern Company parent entity, which does not allocate operating expenses to business segments. Also, this category includes segments below the quantitative threshold for separate disclosure. These segments include providing energy technologies and services to electric utilities and large industrial, commercial, institutional, and municipal customers; as well as investments in telecommunications and leveraged lease projects. All other inter-segment revenues are not material. Financial data for business segments and products and services for the years ended December 31, 2016, 2015, and 2014 was as follows:

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NOTES (continued)
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	Electric Utilities Traditional Electric Operating Companies (in millions)	Southern Power	Eliminations	Total	Southern Company Gas	All Other	Eliminations	Consolidated
2016								
Operating revenues	$16,803	$1,577	$ (439)	$17,941	$ 1,652	$463	$ (160)	$ 19,896
Depreciation and amortization	1,881	352	—	2,233	238	31	—	2,502
Interest income	6	7	—	13	2	20	(15)	20
Earnings from equity method investments	2	—	—	2	60	(3)	—	59
Interest expense	814	117	—	931	81	317	(12)	1,317
Income taxes	1,286	(195)	—	1,091	76	(216)	—	951
Segment net income (loss)[(a) (b)]	2,233	338	—	2,571	114	(230)	(7)	2,448
Total assets	72,141	15,169	(316)	86,994	21,853	2,474	(1,624)	109,697
Gross property additions	4,852	2,114	—	6,966	618	41	(1)	7,624
2015								
Operating revenues	$16,491	$1,390	$ (439)	$17,442	$ —	$152	$ (105)	$ 17,489
Depreciation and amortization	1,772	248	—	2,020	—	14	—	2,034
Interest income	19	2	1	22	—	6	(5)	23
Earnings from equity method investments	1	—	—	1	—	(1)	—	—
Interest expense	697	77	—	774	—	69	(3)	840
Income taxes	1,305	21	—	1,326	—	(132)	—	1,194
Segment net income (loss)[(a) (b)]	2,186	215	—	2,401	—	(32)	(2)	2,367
Total assets	69,052	8,905	(397)	77,560	—	1,819	(1,061)	78,318
Gross property additions	5,124	1,005	—	6,129	—	40	—	6,169
2014								
Operating revenues	$17,354	$1,501	$ (449)	$18,406	$ —	$159	$ (98)	$ 18,467
Depreciation and amortization	1,709	220	—	1,929	—	16	—	1,945
Interest income	17	1	—	18	—	3	(2)	19
Earnings from equity method investments	1	—	—	1	—	(1)	—	—
Interest expense	705	89	—	794	—	43	(2)	835
Income taxes	1,056	(3)	—	1,053	—	(76)	—	977
Segment net income (loss)[(a) (b)]	1,797	172	—	1,969	—	(3)	(3)	1,963
Total assets[(c)]	64,300	5,233	(131)	69,402	—	1,143	(312)	70,233
Gross property additions	5,568	942	—	6,510	—	11	1	6,522

(a) Attributable to Southern Company.

(b) Segment net income (loss) for the traditional electric operating companies includes pre-tax charges for estimated probable losses on the Kemper IGCC of $428 million ($264 million after tax) in 2016, $365 million ($226 million after tax) in 2015, and $868 million ($536 million after tax) in 2014. See Note 3 under "Integrated Coal Gasification Combined Cycle – Kemper IGCC Schedule and Cost Estimate" for additional information.

(c) Net of $202 million of unamortized debt issuance costs as of December 31, 2014. Also net of $488 million of deferred tax assets as of December 31, 2014.

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Products and Services

Electric Utilities' Revenues

Year	Retail	Wholesale	Other	Total
	(in millions)			
2016	$15,234	$ 1,926	$781	$17,941
2015	14,987	1,798	657	17,442
2014	15,550	2,184	672	18,406

Southern Company Gas' Revenues

Year	Gas Distribution Operations	Gas Marketing Services	All Other	Total
	(in millions)			
2016	$1,266	$ 354	$ 32	$1,652

NOTES (continued)
Southern Company and Subsidiary Companies 2016 Annual Report

14. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)
Summarized quarterly financial information for 2016 and 2015 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Consolidated Net Income Attributable to Southern Company	Per Common Share Basic Earnings	Diluted Earnings	Dividends	Trading Price Range High	Low
	(in millions)							
March 2016	$3,992	$ 940	$ 489	$0.53	$ 0.53	$ 0.5425	$51.73	$46.00
June 2016	4,459	1,185	623	0.67	0.66	0.5600	53.64	47.62
September 2016	6,264	1,917	1,139	1.18	1.17	0.5600	54.64	50.00
December 2016	5,181	587	197	0.20	0.20	0.5600	52.23	46.20
March 2015	$4,183	$ 957	$ 508	$0.56	$ 0.56	$ 0.5250	$53.16	$43.55
June 2015	4,337	1,098	629	0.69	0.69	0.5425	45.44	41.40
September 2015	5,401	1,649	959	1.05	1.05	0.5425	46.84	41.81
December 2015	3,568	578	271	0.30	0.30	0.5425	47.50	43.38

In accordance with the adoption of ASU 2016-09 (see Note 1 under "Recently Issued Accounting Standards"), previously reported amounts for income tax expense were reduced by $9 million in the third quarter 2016, $11 million in the second quarter 2016, and $5 million in the first quarter 2016. In addition, basic and diluted EPS increased from previously reported amounts of $1.17 and $1.16 in the third quarter 2016, respectively, $0.65 and $0.65 in the second quarter 2016, respectively, and $0.53 and $0.53 in the first quarter 2016, respectively.

As a result of the revisions to the cost estimate for the Kemper IGCC, Southern Company recorded total pre-tax charges to income for the estimated probable losses on the Kemper IGCC of $206 million ($127 million after tax) in the fourth quarter 2016, $88 million ($54 million after tax) in the third quarter 2016, $81 million ($50 million after tax) in the second quarter 2016, $53 million ($33 million after tax) in the first quarter 2016, $183 million ($113 million after tax) in the fourth quarter 2015, $150 million ($93 million after tax) in the third quarter 2015, $23 million ($14 million after tax) in the second quarter 2015, and $9 million ($6 million after tax) in the first quarter 2015. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information.

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

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SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA
For the Periods Ended December 2012 through 2016
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	2016[(a)]	2015	2014	2013	2012
Operating Revenues (in millions)	$19,896	$17,489	$18,467	$17,087	$16,537
Total Assets (in millions)[(b)(c)]	$109,697	$78,318	$70,233	$64,264	$62,814
Gross Property Additions (in millions)	$7,624	$6,169	$6,522	$5,868	$5,059
Return on Average Common Equity (percent)	10.80	11.68	10.08	8.82	13.10
Cash Dividends Paid Per Share of Common Stock	$2.2225	$2.1525	$2.0825	$2.0125	$1.9425
Consolidated Net Income Attributable to Southern Company (in millions)	$2,448	$2,367	$1,963	$1,644	$2,350
Earnings Per Share —					
Basic	$2.57	$2.60	$2.19	$1.88	$2.70
Diluted	2.55	2.59	2.18	1.87	2.67
Capitalization (in millions):					
Common stock equity	$24,758	$20,592	$19,949	$19,008	$18,297
Preferred and preference stock of subsidiaries and noncontrolling interests	1,854	1,390	977	756	707
Redeemable preferred stock of subsidiaries	118	118	375	375	375
Redeemable noncontrolling interests	164	43	39	—	—
Long-term debt[(b)]	42,629	24,688	20,644	21,205	19,143
Total (excluding amounts due within one year)	$69,523	$46,831	$41,984	$41,344	$38,522
Capitalization Ratios (percent):					
Common stock equity	35.6	44.0	47.5	46.0	47.5
Preferred and preference stock of subsidiaries and noncontrolling interests	2.7	3.0	2.3	1.8	1.8
Redeemable preferred stock of subsidiaries	0.2	0.3	0.9	0.9	1.0
Redeemable noncontrolling interests	0.2	0.1	0.1	—	—
Long-term debt[(b)]	61.3	52.6	49.2	51.3	49.7
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0
Other Common Stock Data:					
Book value per share	$25.00	$22.59	$21.98	$21.43	$21.09
Market price per share:					
High	$54.64	$53.16	$51.28	$48.74	$48.59
Low	46.00	41.40	40.27	40.03	41.75
Close (year-end)	49.19	46.79	49.11	41.11	42.81
Market-to-book ratio (year-end) (percent)	196.8	207.2	223.4	191.8	203.0
Price-earnings ratio (year-end) (times)	19.1	18.0	22.4	21.9	15.9
Dividends paid (in millions)	$2,104	$1,959	$1,866	$1,762	$1,693
Dividend yield (year-end) (percent)	4.5	4.6	4.2	4.9	4.5
Dividend payout ratio (percent)	86.0	82.7	95.0	107.1	72.0
Shares outstanding (in thousands):					
Average	951,332	910,024	897,194	876,755	871,388
Year-end	990,394	911,721	907,777	887,086	867,768
Stockholders of record (year-end)	126,338	131,771	137,369	143,800	149,628

(a) The 2016 selected financial and operating data includes the operations of Southern Company Gas from the date of the Merger, July 1, 2016, through December 31, 2016. See Note 12 under "Merger with Southern Company Gas" for additional information.

(b) A reclassification of debt issuance costs from Total Assets to Long-term debt of $202 million, $139 million, and $133 million is reflected for years 2014, 2013, and 2012, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(c) A reclassification of deferred tax assets from Total Assets of $488 million, $143 million, and $202 million is reflected for years 2014, 2013, and 2012, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

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SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA (continued)
For the Periods Ended December 2012 through 2016
Southern Company and Subsidiary Companies 2016 Annual Report

	2016[(a)]	2015	2014	2013	2012
Operating Revenues (in millions):					
Residential	$6,614	$6,383	$6,499	$6,011	$5,891
Commercial	5,394	5,317	5,469	5,214	5,097
Industrial	3,171	3,172	3,449	3,188	3,071
Other	55	115	133	128	128
Total retail	15,234	14,987	15,550	14,541	14,187
Wholesale	1,926	1,798	2,184	1,855	1,675
Total revenues from sales of electricity	17,160	16,785	17,734	16,396	15,862
Natural gas revenues	1,596	—	—	—	—
Other revenues	1,140	704	733	691	675
Total	$19,896	$17,489	$18,467	$17,087	$16,537
Kilowatt-Hour Sales (in millions):					
Residential	53,337	52,121	53,347	50,575	50,454
Commercial	53,733	53,525	53,243	52,551	53,007
Industrial	52,792	53,941	54,140	52,429	51,674
Other	883	897	909	902	919
Total retail	160,745	160,484	161,639	156,457	156,054
Wholesale sales	34,896	30,505	32,786	26,944	27,563
Total	195,641	190,989	194,425	183,401	183,617
Average Revenue Per Kilowatt-Hour (cents):					
Residential	12.40	12.25	12.18	11.89	11.68
Commercial	10.04	9.93	10.27	9.92	9.62
Industrial	6.01	5.88	6.37	6.08	5.94
Total retail	9.48	9.34	9.62	9.29	9.09
Wholesale	5.52	5.89	6.66	6.88	6.08
Total sales	8.77	8.79	9.12	8.94	8.64
Average Annual Kilowatt-Hour Use Per Residential Customer	12,387	13,318	13,765	13,144	13,187
Average Annual Revenue Per Residential Customer	$1,541	$1,630	$1,679	$1,562	$1,540
Plant Nameplate Capacity Ratings (year-end) (megawatts)	46,291	44,223	46,549	45,502	45,740
Maximum Peak-Hour Demand (megawatts):					
Winter	32,272	36,794	37,234	27,555	31,705
Summer	35,781	36,195	35,396	33,557	35,479
System Reserve Margin (at peak) (percent)[(b)]	34.2	33.2	19.8	21.5	20.8
Annual Load Factor (percent)	61.5	59.9	59.6	63.2	59.5
Plant Availability (percent):					
Fossil-steam	86.4	86.1	85.8	87.7	89.4
Nuclear	93.3	93.5	91.5	91.5	94.2

(a) The 2016 selected financial and operating data includes the operations of Southern Company Gas from the date of the Merger, July 1, 2016, through December 31, 2016. See Note 12 under "Merger with Southern Company Gas" for additional information.
(b) Beginning in 2014, system reserve margin is calculated to include unrecognized capacity.

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SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA (continued)
For the Periods Ended December 2012 through 2016
Southern Company and Subsidiary Companies 2016 Annual Report

	2016[(a)]	2015	2014	2013	2012
Source of Energy Supply (percent):					
Coal	30.6	32.3	39.3	36.9	35.2
Nuclear	14.7	15.2	14.8	15.5	16.2
Oil and gas	42.2	42.7	37.0	37.2	38.2
Hydro	2.1	2.6	2.5	3.9	1.7
Other renewables	2.4	0.8	0.4	0.1	0.1
Purchased power	8.0	6.4	6.0	6.4	8.6
Total	100.0	100.0	100.0	100.0	100.0
Gas Sales Volumes (mmBtu in millions):					
Firm	296	—	—	—	—
Interruptible	53	—	—	—	—
Total	349	—	—	—	—
Traditional Electric Operating Company Customers (year-end) (in thousands):					
Residential	3,970	3,928	3,890	3,859	3,832
Commercial[(b)]	595	590	586	582	579
Industrial[(b)]	17	17	17	17	17
Other	11	11	11	9	8
Total electric customers	4,593	4,546	4,504	4,467	4,436
Gas distribution operations customers	4,586	—	—	—	—
Total utility customers	9,179	4,546	4,504	4,467	4,436
Employees (year-end)	32,020	26,703	26,369	26,300	26,439

(a) The 2016 selected financial and operating data includes the operations of Southern Company Gas from the date of the Merger, July 1, 2016, through December 31, 2016. See Note 12 under "Merger with Southern Company Gas" for additional information.

(b) A reclassification of customers from commercial to industrial is reflected for years 2012-2015 to be consistent with the rate structure approved by the Georgia PSC. The impact to operating revenues, kilowatt-hour sales, and average revenue per kilowatt-hour by class is not material.

ALABAMA POWER COMPANY
FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Alabama Power Company 2016 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, 2016.

/s/ Mark A. Crosswhite
Mark A. Crosswhite
Chairman, President, and Chief Executive Officer
/s/ Philip C. Raymond
Philip C. Raymond
Executive Vice President, Chief Financial Officer, and Treasurer
February 21, 2017

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, 2016 and 2015, 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, 2016. 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 II-182 to II-226) present fairly, in all material respects, the financial position of Alabama Power Company as of December 31, 2016 and 2015, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.
/s/ Deloitte & Touche LLP
Birmingham, Alabama
February 21, 2017

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DEFINITIONS

Term	Meaning
AFUDC	Allowance for funds used during construction
ARO	Asset retirement obligation
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
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
FASB	Financial Accounting Standards Board
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 electric operating companies and Southern Power (excluding subsidiaries) 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 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	S&P Global Ratings, a division of S&P Global 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 Gas	Southern Company Gas (formerly known as AGL Resources Inc.) and its subsidiaries

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DEFINITIONS
(continued)

Term	Meaning
Southern Company system	Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), SEGCO, Southern Nuclear, SCS, Southern LINC, PowerSecure, Inc. (as of May 9, 2016), and other subsidiaries
Southern LINC	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
traditional electric 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 2016 Annual Report
OVERVIEW
Business Activities
Alabama Power Company (the Company) operates as a vertically integrated utility providing electric service 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 providing electric service. 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, 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.
The Company continues to focus on several key performance indicators including, but not limited to, 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.
See RESULTS OF OPERATIONS herein for information on the Company's financial performance.
Earnings
The Company's 2016 net income after dividends on preferred and preference stock was $822 million, representing a $37 million, or 4.7%, increase over the previous year. The increase was due primarily to an increase in retail revenues under Rate CNP Compliance, an increase in weather-related revenues, and a decrease in operations and maintenance expenses not related to fuel or Rate CNP Compliance. These increases to income were partially offset by an accrual for an expected Rate RSE refund, a decrease in AFUDC equity, and an increase in depreciation. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Rate RSE" herein for additional information.
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.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2016 Annual Report

RESULTS OF OPERATIONS
A condensed income statement for the Company follows:

	Amount	Increase (Decrease) from Prior Year	
	2016	2016	2015
	(in millions)		
Operating revenues	$5,889	$ 121	$ (174)
Fuel	1,297	(45)	(263)
Purchased power	334	(17)	(34)
Other operations and maintenance	1,510	9	33
Depreciation and amortization	703	60	40
Taxes other than income taxes	380	12	12
Total operating expenses	4,224	19	(212)
Operating income	1,665	102	38
Allowance for equity funds used during construction	28	(32)	11
Interest income	16	1	—
Interest expense, net of amounts capitalized	302	28	19
Other income (expense), net	(37)	10	(25)
Income taxes	531	25	(6)
Net income	839	28	11
Dividends on preferred and preference stock	17	(9)	(13)
Net income after dividends on preferred and preference stock	$822	$ 37	$ 24

Operating Revenues
Operating revenues for 2016 were $5.9 billion, reflecting a $121 million increase from 2015. Details of operating revenues were as follows:

	Amount	
	2016	2015
	(in millions)	
Retail — prior year	$5,234	$5,249
Estimated change resulting from —		
Rates and pricing	147	204
Sales decline	(20)	(11)
Weather	31	(43)
Fuel and other cost recovery	(70)	(165)
Retail — current year	5,322	5,234
Wholesale revenues —		
Non-affiliates	283	241
Affiliates	69	84
Total wholesale revenues	352	325
Other operating revenues	215	209
Total operating revenues	$5,889	$5,768
Percent change	2.1 %	(2.9)%

Retail revenues in 2016 were $5.3 billion. These revenues increased $88 million, or 1.7%, in 2016 and decreased $15 million, or 0.3%, in 2015, each as compared to the prior year. The increase in 2016 was due to an increase in revenues under Rate CNP

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2016 Annual Report

Compliance as a result of increased net investments, partially offset by a decrease in fuel revenues and an accrual for an expected Rate RSE refund. The decrease in 2015 was due to a decrease in fuel revenues and milder weather in 2015 as compared to 2014, partially offset by an increase in revenues due to a Rate RSE increase effective January 1, 2015. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate RSE" 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:

	2016	2015	2014
	(in millions)		
Capacity and other	$154	$140	$154
Energy	129	101	127
Total non-affiliated	$283	$241	$281

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 electric 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 affect 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 2016, wholesale revenues from sales to non-affiliates increased $42 million, or 17.4%, as compared to the prior year primarily due to a $28 million increase in revenues from energy sales and a $14 million increase in capacity revenues. In 2016, KWH sales increased 33.3% primarily due to a new wholesale contract in the first quarter 2016 partially offset by a 12.1% decrease in the price of energy due to lower natural gas prices. 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.

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 2016, wholesale revenues from sales to affiliates decreased $15 million, or 17.9%, as compared to the prior year. In 2016, KWH sales decreased 15.7% as a result of lower-cost generation available in the Southern Company system and a 2.6% decrease in the price of energy primarily due to lower natural gas prices. 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 available in the Southern Company system and a 32.8% decrease in the price of energy primarily due to lower 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.

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Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2016 and the percent change from the prior year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2016	2016	2015	2016	2015
	(in billions)				
Residential	18.4	1.4 %	(3.4)%	(0.5)%	0.1 %
Commercial	14.1	(0.1)	(0.1)	(0.5)	0.1
Industrial	22.3	(4.6)	(1.8)	(4.6)	(1.8)
Other	0.2	3.8	(4.9)	3.8	(4.9)
Total retail	55.0	(1.5)	(1.9)	(2.2)%	(0.7)%
Wholesale					
Non-affiliates	5.9	37.1	(6.3)		
Affiliates	3.2	(15.7)	(33.8)		
Total wholesale	9.1	12.5	(21.5)		
Total energy sales	64.1	0.3 %	(4.9)%		

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 2016 were 1.5% lower than in 2015. Residential sales increased 1.4% primarily due to warmer weather in the third quarter 2016 as compared to the corresponding period in 2015. Commercial sales remained flat in 2016. Weather-adjusted residential sales were flat in 2016 due to lower customer usage primarily resulting from an increase in efficiency improvements in residential appliances and lighting, partially offset by customer growth. Industrial sales decreased 4.6% in 2016 compared to 2015 as a result of a decrease in demand resulting from changes in production levels primarily in the primary metals, chemical, pipelines, paper, and stone, clay, and glass sectors. A strong dollar, low oil prices, and weak global growth conditions constrained growth in the industrial sector in 2016.

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 constrained growth in the industrial sector in 2015.

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.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2016 Annual Report

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

	2016	2015	2014
Total generation (in billions of KWHs)	60.2	60.9	63.6
Total purchased power (in billions of KWHs)	7.1	6.3	6.6
Sources of generation (percent) —			
Coal	53	54	54
Nuclear	23	24	23
Gas	19	16	17
Hydro	5	6	6
Cost of fuel, generated (in cents per net KWH) —			
Coal	2.75	2.83	3.14
Nuclear	0.78	0.81	0.84
Gas	2.67	2.94	3.69
Average cost of fuel, generated (in cents per net KWH)[(a)]	2.26	2.34	2.68
Average cost of purchased power (in cents per net KWH)[(b)]	4.80	5.66	5.92

(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 $1.6 billion in 2016, a decrease of $62 million, or 3.7%, compared to 2015. The decrease was primarily due to a $61 million decrease in the average cost of purchased power, and a $59 million decrease in the average cost of fuel, partially offset by a $49 million increase related to the volume of KWHs purchased.

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 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 2016, a decrease of $45 million, or 3.4%, compared to 2015. The decrease was primarily due to a 9.2% decrease in the average cost of KWHs generated by natural gas, which excludes tolling agreements, a 4.2% and 3.9% decrease in the volume of KWHs generated by nuclear fuel and coal, respectively, and a 3.7% decrease in the average cost of KWHs generated by nuclear fuel, partially offset by a 17.4% increase in the volume of KWHs generated by natural gas. 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.

Purchased Power – Non-Affiliates

In 2016, purchased power expense from non-affiliates was $166 million, a decrease of $5 million, or 2.9%, compared to 2015. This decrease is immaterial. 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.
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 electric service territory, and the availability of the Southern Company system's generation.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2016 Annual Report

Purchased Power – Affiliates

Purchased power expense from affiliates was $168 million in 2016, a decrease of $12 million, or 6.7%, compared to 2015. This decrease was primarily due to a 20.7% decrease in the average cost per KWH purchased due to lower gas prices, partially offset by a 17.5% increase in the amount of energy purchased due to the availability of lower-cost generation compared to the Company's owned generation. 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.

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 2016, other operations and maintenance expenses increased $9 million, or 0.6%, as compared to the prior year. Steam production costs increased $28 million primarily due to the timing of generation operating expenses. Transmission and distribution expenses increased $10 million and $7 million, respectively, primarily due to additional vegetation management and other maintenance expenses. These increases were partially offset by a decrease of $32 million in employee benefit costs, including pension costs. The increases in operations and maintenance expenses were primarily Rate CNP compliance-related costs and therefore had no significant impact to net income. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Rate CNP Compliance" herein for additional information.

In 2015, other operations and maintenance expenses increased $33 million, or 2.2%, as compared to the prior year. Employee benefit costs, including pension costs, increased $40 million. Nuclear production expenses increased $19 million primarily due to outage amortization costs. These increases were partially offset by decreases in steam production expenses of $21 million primarily due to the timing of outages and distribution expenses of $12 million primarily related to overhead line maintenance expenses.

See Note 2 to the financial statements under "Pension Plans" for additional information.

Depreciation and Amortization

Depreciation and amortization increased $60 million, or 9.3%, in 2016 as compared to the prior year primarily due to compliance related steam projects placed in service. Depreciation and amortization increased $40 million, or 6.6%, in 2015 as compared to the prior year. The increase was primarily due to the amortization of $120 million of a 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. 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 3.3%, in 2016 and $12 million, or 3.4%, in 2015 as compared to prior years. These increases were 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 decreased $32 million, or 53.3%, in 2016 as compared to the prior year. The decrease was primarily associated with environmental compliance and steam generation capital projects being placed in service in 2016. AFUDC equity increased $11 million, or 22.4%, in 2015 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 $28 million, or 10.2%, in 2016 as compared to the prior year primarily due to an increase in debt outstanding and a reduction in the 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.

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Other Income (Expense), Net
Other income (expense), net increased $10 million, or 21.3%, in 2016 as compared to the prior year primarily due to a decrease in donations, partially offset by a decrease in sales of non-utility property. Other income (expense), net decreased $25 million, or 113.6%, in 2015 as compared to the prior year primarily due to an increase in donations and a decrease in sales of non-utility property.
Income Taxes
Income taxes increased $25 million, or 4.9%, in 2016 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 $9 million, or 34.6%, in 2016 and $13 million, or 33.3%, in 2015 as compared to the prior years. The decreases were 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 and Preference 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 electric service to retail and wholesale customers within its traditional service territory located in the State of Alabama and 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 – 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 and limited projected demand growth over the next several years. Future earnings will be driven primarily by customer growth. Earnings will also depend upon maintaining and growing sales, considering, among other things, the adoption and/or penetration rates of increasingly energy-efficient technologies and increasing volumes of electronic commerce transactions. Earnings are subject to a variety of other 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 primarily 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. Current proposals related to potential tax reform legislation are primarily focused on reducing the corporate income tax rate, allowing 100% of capital expenditures to be deducted, and eliminating the interest deduction. The ultimate impact of any tax reform proposals is dependent on the final form of any legislation enacted and the related transition rules and cannot be determined at this time, but could have a material impact on the Company's financial statements.

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 Compliance" 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 2016, the Company had invested approximately $4.2 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $260 million, $349 million, and $355 million for 2016, 2015, and 2014, respectively. The Company expects that capital expenditures to comply with environmental statutes and regulations will total approximately $1.3 billion from 2017 through 2021, with annual totals of approximately $471 million, $349 million, $115 million, $142 million, and $196 million for 2017, 2018, 2019, 2020, and 2021, respectively. These estimated expenditures do not include any potential capital expenditures that may arise from the EPA's final rules and guidelines or future state plans that would limit CO_2 emissions from existing, new, modified, or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" herein for additional information. The Company also anticipates costs associated with ash pond closure and ground water monitoring under the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), which are reflected in the Company's ARO liabilities. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" and Note 1 to the financial statements under "Asset Retirement Obligations and Other Cost of Removal" 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 time periods over which compliance with regulations is required; individual state implementation of regulations, as applicable; the outcome of any legal challenges to the environmental rules; any additional rulemaking activities in response to legal challenges and court decisions; the cost, availability, and existing inventory of emissions allowances; the impact of future changes in generation and emissions-related technology; the Company's fuel mix; and environmental remediation requirements. 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.

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.

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 implementation strategy for the MATS rule included emission controls, retirements, and fuel conversions at affected units. All of the Company's units that are subject to the MATS rule completed the measures necessary to achieve compliance with this rule or were retired prior to or during 2016.

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. In October 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

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facilities. States were required to recommend area designations by October 2016, and no areas within the Company's service territory were proposed for designation as nonattainment.

The EPA regulates fine particulate matter concentrations through an annual and 24-hour average NAAQS, based on standards promulgated in 1997, 2006, and 2012. All areas in which the Company's generating units are located have been determined by the EPA to be in attainment with those standards.

In 2010, the EPA revised the NAAQS for sulfur dioxide (SO_2), establishing a new one-hour standard. No areas within the Company's service territory have been designated as nonattainment under this standard. However, in 2015, the EPA finalized a data requirements rule to support final EPA designation decisions for all remaining areas under the SO_2 standard, which could result in nonattainment designations for areas within the Company's service territory. Nonattainment designations could require additional reductions in SO_2 emissions and increased compliance and operational costs.

In 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 owned by SEGCO, which is jointly owned with Georgia Power.

On July 6, 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide (NO_x) emissions from power plants in two phases – Phase 1 in 2015 and Phase 2 in 2017. On October 26, 2016, the EPA published a final rule that updates the CSAPR ozone season NO_x program, beginning in 2017, and establishes more stringent ozone-season emissions budgets in Alabama. Alabama is also in the CSAPR annual SO_2 and NO_x programs.

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. On December 14, 2016, the EPA finalized revisions to the regional haze regulations. These regulations establish a deadline of July 31, 2021 for states to submit revised SIPs to the EPA demonstrating reasonable progress toward the statutory goal of achieving natural background conditions by 2064. State implementation of the reasonable progress requirements defined in this final rule could require further reductions in SO_2 or NO_x emissions.

In June 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).

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. 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. The ultimate impact of the eight-hour ozone and SO_2 NAAQS, Alabama opacity rule, CSAPR, regional haze regulations, and SSM rule will depend on various factors, such as implementation, adoption, or other action at the state level, and the outcome of pending and/or future legal challenges, and cannot be determined at this time.

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

2014. The effect of this final rule will depend on the results of additional studies that are currently underway and implementation of the rule by regulators based on site-specific factors. National Pollutant Discharge Elimination System (NPDES) permits issued after July 14, 2018 must include conditions to implement and ensure compliance with the standards and protective measures required by the rule.

In November 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 NPDES 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.

In 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 in August 2015 but, in October 2015, the U.S. Court of Appeals for the Sixth Circuit issued an order staying implementation of the final rule. The case is held in abeyance pending review by the U.S. Supreme Court of challenges to the U.S. Court of Appeals for the Sixth Circuit's jurisdiction in the case.

These water quality regulations could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions and decisions on infrastructure expansion and improvements. 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. The ultimate impact of these final rules will depend on various factors, such as pending and/or future legal challenges, compliance dates, and implementation of the rules, and cannot be determined at this time.

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.

The CCR Rule became effective in October 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. On December 16, 2016, President Obama signed the Water Infrastructure Improvements for the Nation Act (WIIN Act). The WIIN Act allows states to establish permit programs for implementing the CCR Rule, if the EPA approves the program, and allows for federal permits and EPA enforcement where a state permitting program does not exist.

Based on current cost estimates for closure in place and monitoring primarily related to ash ponds pursuant to the CCR Rule, the Company has 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 with respect to compliance activities, the Company expects to continue to periodically update these estimates. The Company has posted closure and post-closure care plans to its public website as required by the CCR Rule; however, the ultimate impact of the CCR Rule will depend on the results of initial and ongoing minimum criteria assessments and the implementation of state or federal permit programs. 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, 2016.

Global Climate Issues

In October 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 review with the courts. The stay will remain in effect through the resolution of the litigation, including any review by 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 and decisions on infrastructure expansion and improvements. 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 outcome of pending legal challenges, including legal challenges filed by the traditional electric operating companies, and any individual state implementation of the EPA's final guidelines in the event the rule is upheld and implemented.
In December 2015, parties to the United Nations Framework Convention on Climate Change – including the United States – adopted 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 tracking progress toward the goals every five years. The ultimate impact of this agreement depends on its implementation by participating countries and cannot be determined at this time.
The EPA's greenhouse gas reporting rule requires annual reporting of greenhouse gas emissions expressed in terms of metric tons of CO_2 equivalent emissions for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2015 greenhouse gas emissions were approximately 39 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2016 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 electric operating companies (including the Company) and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In April 2015, the FERC issued an order finding that the traditional electric 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 electric operating companies and in some adjacent areas. The FERC directed the traditional electric 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 electric operating companies (including the Company) and Southern Power filed a request for rehearing in May 2015 and in June 2015 filed their response with the FERC.
On December 9, 2016, the traditional electric operating companies (including the Company) and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' (including the Company's) and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies (including the Company) and in some adjacent areas. The traditional electric operating companies (including the Company) and Southern Power expect to make a compliance filing within 30 days accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.
The ultimate outcome of these matters 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, the excess will be refunded to customers unless otherwise directed by the Alabama PSC; however, there is no provision for additional customer billings should the actual retail return fall below the WCE range.

On December 1, 2016, the Company made its required annual Rate RSE submission to the Alabama PSC of projected data for calendar year 2017. The Rate RSE adjustment was an increase of 4.48%, or $245 million annually, effective January 1, 2017 and includes the performance based adder of 0.07%. Under the terms of Rate RSE, the maximum increase for 2018 cannot exceed 3.52%.

As of December 31, 2016, the 2016 retail return exceeded the allowed WCE range; therefore, the Company established a $73 million Rate RSE refund liability. In accordance with an order issued on February 14, 2017 by the Alabama PSC, the Company was directed to apply the full amount of the refund to reduce the under recovered balance of Rate CNP PPA.

Rate CNP PPA

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 8, 2016, 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, 2016 through March 31, 2017. No adjustment to Rate CNP PPA is expected in 2017.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, the Company was authorized to eliminate the under recovered balance in Rate CNP PPA at December 31, 2016, which totaled approximately $142 million. As discussed herein under "Rate RSE," the Company will utilize the full amount of its $73 million Rate RSE refund liability to reduce the amount of the Rate CNP PPA under recovery and will reclassify the remaining $69 million to a separate regulatory asset. The amortization of the new regulatory asset through Rate RSE will begin concurrently with the effective date of the Company's next depreciation study, which is expected to occur within the next three to five years. The Company's current depreciation study became effective January 1, 2017.

Rate CNP Compliance

Rate CNP Compliance allows for the recovery of the Company's retail costs associated with laws, regulations, and other such mandates directed at the utility industry involving the environment, security, reliability, safety, sustainability, or similar considerations impacting the Company's facilities or operations. 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. Revenues for Rate CNP Compliance, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in Rate CNP Compliance related operations and maintenance expenses and depreciation generally will have no effect on net income.

On December 6, 2016, the Alabama PSC issued a consent order that the Company leave in effect for 2017 the factors associated with the Company's compliance costs for the year 2016. As stated in the consent order, any under-collected amount for prior years will be deemed recovered before the recovery of any current year amounts. Any under recovered amounts associated with 2017 will be reflected in the 2018 filing.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, the Company is authorized to classify any under recovered balance in Rate CNP Compliance up to approximately $36 million to a separate regulatory asset. The amortization of the new regulatory asset through Rate RSE will begin concurrently with the effective date of the Company's next depreciation study, which is expected to occur within the next three to five years. The Company's current depreciation study became effective January 1, 2017.

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 6, 2016, the Alabama PSC approved a decrease in the Company's Rate ECR factor from 2.030 to 2.015 cents per KWH, equal to 0.15%, or $8 million annually, based upon projected billings, effective January 1, 2017. 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 2017. The rate will return to 5.910 cents per KWH in 2018, absent a further order from the Alabama PSC.

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In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, the Company is authorized to classify any under recovered balance in Rate ECR up to approximately $36 million to a separate regulatory asset. The amortization of the new regulatory asset through Rate RSE will begin concurrently with the effective date of the Company's next depreciation study, which is expected to occur within the next three to five years. The Company's current depreciation study became effective January 1, 2017.

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 2016, as part of its environmental compliance strategy, the Company ceased using coal at Plant Greene County Units 1 and 2 (300 MWs representing the Company's ownership interest) and began operating Units 1 and 2 solely on natural gas in June 2016 and July 2016, respectively. As a result, 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 units' remaining useful lives, as established prior to the decision for retirement; therefore, these decisions associated with coal operations had no significant impact on the Company's financial statements.

Renewables

In accordance with the September 2015 Alabama PSC order approving up to 500 MWs of renewable projects, the Company has entered into agreements to purchase power from and to build 89 MWs of renewable generation sources. The terms of the agreements permit the Company to use the energy and retire the associated renewable energy credits (REC) in service of its customers or to sell RECs, separately or bundled with energy.

Income Tax Matters

Bonus Depreciation

In December 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. Bonus depreciation was extended for qualified property placed in service through 2020. The PATH Act allows for 50% bonus depreciation for 2015 through 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 bonus depreciation included in the PATH Act is expected to result in approximately $230 million of positive cash flows for the 2016 tax year and approximately $180 million for the 2017 tax year. See Note 5 to the financial statements under "Current and Deferred Income Taxes" for additional information.

Other Matters

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters.

The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

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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.

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 other 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 related to ongoing repair and maintenance, 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, asbestos containing material within long-term assets not subject to ongoing repair and maintenance activities, 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 cost estimates for AROs related to the disposal of CCR 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 with respect to compliance activities, 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. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Coal Combustion Residuals" herein for additional information. Given the significant judgment involved in estimating AROs, the Company considers the liabilities for AROs to be critical accounting estimates.

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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 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 decreased 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 an $8 million or less change in total annual benefit expense and a $105 million or less change in projected obligations.

The Company recorded pension costs of $11 million in 2016, $48 million in 2015, and $23 million in 2014. Postretirement benefit costs for the Company were $4 million, $5 million, and $4 million in 2016, 2015, and 2014, respectively. Such amounts are dependent on several factors including trust earnings and changes to the plans. A portion of pension and other postretirement benefit costs is capitalized based on construction-related labor charges. Pension and other postretirement benefit costs are a component of the regulated rates and generally do not have a long-term effect on net income.

See Note 2 to the financial statements for additional information regarding pension and other postretirement benefits.

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

In 2014, the FASB issued ASC 606, Revenue from Contracts with Customers, replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the guidance is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

While the Company expects most of its revenue to be included in the scope of ASC 606, it has not fully completed its evaluation of such arrangements. The majority of the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term. For such arrangements, the Company generally expects that the revenue from contracts with these customers will continue to be equivalent to the electricity supplied and billed in that period (including unbilled revenues) and the adoption of ASC 606 will not result in a significant shift in the timing of revenue recognition for such sales.

The Company's ongoing evaluation of other revenue streams and related contracts includes longer term contractual commitments and unregulated sales to customers. Some revenue arrangements, such as certain PPAs and alternative revenue programs, are expected to be excluded from the scope of ASC 606 and therefore, be accounted for and presented separately from revenues under ASC 606 on the Company's financial statements. In addition, the power and utilities industry is currently addressing other specific industry issues, including the applicability of ASC 606 to contributions in aid of construction (CIAC). If final implementation guidance indicates CIAC will be accounted for under ASC 606 and offsetting regulatory treatment is not permitted, it could have a material impact on the Company's financial statements.

The new standard is effective for interim and annual reporting periods beginning after December 15, 2017. The Company must select a transition method to be applied either retrospectively to each prior reporting period presented or retrospectively with a cumulative effect adjustment to retained earnings at the date of initial adoption. As the ultimate impact of the new standard has not yet been determined, the Company has not elected its transition method.

On February 25, 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842) (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company is currently evaluating the new standard and has not yet determined its ultimate impact; however, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

On March 30, 2016, the FASB issued ASU No. 2016-09, Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting (ASU 2016-09). ASU 2016-09 changes the accounting for income taxes and the cash flow presentation for share-based payment award transactions effective for fiscal years beginning after December 15, 2016. The new guidance requires all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation to be recognized as income tax expense or benefit in the income statement. Previously, the Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities rather than net cash provided from financing activities on the statement of cash flows. The Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. The Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of the Company. See Notes 5, 8, and 12 to the financial statements for disclosures impacted by ASU 2016-09.

On October 24, 2016, the FASB issued ASU No. 2016-16, Income Taxes (Topic 740), Intra-Entity Transfers of Assets Other Than Inventory (ASU 2016-16). Current GAAP prohibits the recognition of current and deferred income taxes for an affiliate asset transfer until the asset has been sold to an outside party. ASU 2016-16 requires an entity to recognize the income tax consequences of an affiliate transfer of an asset other than inventory when the transfer occurs. ASU 2016-16 is effective for annual reporting periods beginning after December 15, 2017 and interim periods within those annual periods. The amendments will be applied on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. The Company is currently assessing the impact of the standard on its financial statements and has not yet determined its ultimate impact.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2016. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to maintain existing generation facilities, to comply with environmental regulations including adding environmental modifications to certain existing generating units, to expand and improve transmission and distribution facilities, 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 2017 through 2019, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt issuances, borrowings from financial institutions, preferred and preference stock issuances, or capital contributions from Southern Company. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit

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arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan and the nuclear decommissioning trust funds increased in value as of December 31, 2016 as compared to December 31, 2015. On December 19, 2016, the Company voluntarily contributed $129 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated during 2017. The Company's funding obligations for the nuclear decommissioning trust fund are based on the most recent 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 $1.9 billion for 2016, a decrease of $193 million as compared to 2015. The decrease in cash provided from operating activities was primarily due to the collection of fuel cost recovery revenues and the voluntary contribution to the qualified pension plan, partially offset by the timing of income tax payments and refunds associated with bonus depreciation. 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 and collection of fuel cost recovery revenues, partially offset by the timing of payment of accounts payable.

Net cash used for investing activities totaled $1.4 billion for 2016, $1.5 billion for 2015, and $1.6 billion for 2014. These activities were primarily related to gross property additions for distribution, environmental, transmission, and steam generation assets. In 2014, these activities also related to gross property additions for nuclear fuel assets.

Net cash used for financing activities totaled $285 million in 2016 primarily due to the payment of common stock dividends and a redemption of long-term debt, partially offset by issuances of long-term debt and additional capital contributions from Southern Company. 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. 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 2016 included an increase of $905 million in property, plant, and equipment primarily due to additions to environmental, steam generation, distribution, and transmission facilities, an increase of $413 million in accumulated deferred income taxes primarily as a result of bonus depreciation, and an increase of $361 million in securities due within one year. Other significant changes include a decrease of $310 million in construction work in progress primarily due to environmental equipment related to steam generation facilities being placed in service.

The Company's ratio of common equity to total capitalization plus short-term debt was 46.2% and 45.6% at December 31, 2016 and 2015, 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 from sources similar to those used in the past, which were primarily from 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, will depend upon prevailing market conditions, regulatory approval, and other factors.

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

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.

At December 31, 2016, the Company's current liabilities exceeded current assets by $0.1 billion. The Company's current liabilities sometimes exceed current assets because of long-term debt maturities and the periodic use of short-term debt as a funding source, as well as significant seasonal fluctuations in cash needs.

At December 31, 2016, the Company had approximately $420 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2016 were as follows:

Expires					Expires Within One Year	
2017	2018	2020	Total	Unused	Term Out	No Term Out
(in millions)			(in millions)		(in millions)	
$35	$500	$800	$1,335	$1,335	$ —	$ 35

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

Most of these bank credit arrangements, as well as the Company's term loan 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. At December 31, 2016, the Company was 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 programs. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support was $890 million as of December 31, 2016. In addition, at December 31, 2016, the Company had $87 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

The Company also 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 electric operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each traditional electric operating company under these arrangements are several and there is no cross-affiliate credit support.

The Company had no short-term borrowings outstanding at December 31, 2016, 2015, and 2014. Details of commercial paper borrowings were as follows:

	Short-term Debt During the Period (*)		
	Average Amount Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		(in millions)
December 31, 2016	$ 16	0.6 %	$ 200
December 31, 2015	$ 14	0.2 %	$ 100
December 31, 2014	$ 13	0.2 %	$ 300

(*) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2016, 2015, and 2014.

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 January 2016, 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 corporate purposes, including the Company's continuous construction program.

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In March 2016, the Company entered into three bank term loan agreements with maturity dates of March 2021, in an aggregate principal amount of $45 million, one of which bears interest at 2.38% per annum and two of which bear interest based on three-month LIBOR.

Subsequent to December 31, 2016, the Company repaid at maturity $200 million aggregate principal amount of its Series 2007A 5.55% Senior Notes due February 1, 2017.

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

At December 31, 2016, the Company did 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, 2016 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	$ 332

Included in these amounts are certain agreements that could require collateral in the event that either the Company or Georgia Power 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 January 10, 2017, S&P revised its consolidated credit rating outlook for Southern Company (including the Company) from negative to stable.

Market Price Risk

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

To mitigate future exposure to changes in interest rates, the Company may enter into derivatives designated as hedges. The weighted average interest rate on $1.1 billion of long-term variable interest rate exposure at January 1, 2017 was 1.38%. If the Company sustained a 100 basis point change in interest rates for all long-term variable interest rate exposure, the change would affect annualized interest expense by approximately $11 million at January 1, 2017. See Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements for additional information.

To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and 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, 2016 when compared to the year ended December 31, 2015.
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

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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:

	2016 Changes	2015 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	$(54)	$ (52)
Contracts realized or settled	39	41
Current period changes(*)	27	(43)
Contracts outstanding at the end of the period, assets (liabilities), net	$12	$ (54)

(*) 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:

	2016	2015
	mmBtu Volume	
	(in millions)	
Commodity – Natural gas swaps	68	44
Commodity – Natural gas options	6	6
Total hedge volume	74	50

The weighted average swap contract cost below market prices was approximately $0.14 per mmBtu as of December 31, 2016 and above market prices was approximately $1.13 per mmBtu as of December 31, 2015. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. Substantially all of the natural gas hedge gains and losses are recovered through the Company's retail energy cost recovery clause.

At December 31, 2016 and 2015, 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.

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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 of the fair value hierarchy. 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, 2016 were as follows:

	Fair Value Measurements December 31, 2016		
	Total Fair Value	Maturity Year 1	Years 2&3
	(in millions)		
Level 1	$—	$ —	$ —
Level 2	12	8	4
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$12	$ 8	$ 4

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 $1.9 billion for 2017, $1.6 billion for 2018, $1.2 billion for 2019, $1.2 billion for 2020, and $1.2 billion for 2021. 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 $0.5 billion for 2017, $0.3 billion for 2018, $0.1 billion for 2019, $0.1 billion for 2020, and $0.2 billion for 2021. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's final rules and guidelines or future state plans that would limit CO_2 emissions from new, existing, 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 monitoring of ash ponds in accordance with the CCR Rule, which are reflected in 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 activities, are estimated to be $31 million, $26 million, $100 million, $105 million, and $107 million for the years 2017, 2018, 2019, 2020, and 2021, 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 generating 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.

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Contractual Obligations

Contractual obligations at December 31, 2016 were as follows:

	2017	2018-2019	2020-2021	After 2021	Total
	(in millions)				
Long-term debt[a] —					
Principal	$561	$200	$560	$5,827	$7,148
Interest	290	521	492	4,013	5,316
Preferred and preference stock dividends[b]	17	35	35	—	87
Financial derivative obligations[c]	5	4	—	—	9
Operating leases[d]	14	20	16	10	60
Capital Lease	1	1	1	3	6
Purchase commitments —					
Capital[e]	1,782	2,554	2,185	—	6,521
Fuel[f]	1,069	1,404	631	355	3,459
Purchased power[g]	81	174	189	722	1,166
Other[h]	44	86	52	274	456
Pension and other postretirement benefit plans[i]	19	38	—	—	57
Total	$3,883	$5,037	$4,161	$11,204	$24,285

(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, 2017, 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 five-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, 2016, 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, 2016.

(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.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2016 Annual Report

Cautionary Statement Regarding Forward-Looking Statements
The Company's 2016 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning regulated rates, customer and sales growth, economic conditions, 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, filings with state and federal regulatory authorities, impact of the PATH Act, federal income tax benefits, 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 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, including potential tax reform legislation, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries;
- 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 foreign 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, 2016, 2015, and 2014
Alabama Power Company 2016 Annual Report

	2016	2015	2014
	(in millions)		
Operating Revenues:			
Retail revenues	$5,322	$5,234	$5,249
Wholesale revenues, non-affiliates	283	241	281
Wholesale revenues, affiliates	69	84	189
Other revenues	215	209	223
Total operating revenues	5,889	5,768	5,942
Operating Expenses:			
Fuel	1,297	1,342	1,605
Purchased power, non-affiliates	166	171	185
Purchased power, affiliates	168	180	200
Other operations and maintenance	1,510	1,501	1,468
Depreciation and amortization	703	643	603
Taxes other than income taxes	380	368	356
Total operating expenses	4,224	4,205	4,417
Operating Income	1,665	1,563	1,525
Other Income and (Expense):			
Allowance for equity funds used during construction	28	60	49
Interest expense, net of amounts capitalized	(302)	(274)	(255)
Other income (expense), net	(21)	(32)	(7)
Total other income and (expense)	(295)	(246)	(213)
Earnings Before Income Taxes	1,370	1,317	1,312
Income taxes	531	506	512
Net Income	839	811	800
Dividends on Preferred and Preference Stock	17	26	39
Net Income After Dividends on Preferred and Preference Stock	$822	$785	$761

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

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STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2016, 2015, and 2014
Alabama Power Company 2016 Annual Report

	2016	2015	2014
	(in millions)		
Net Income	$839	$811	$800
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(1), $(3), and $(3), respectively	(2)	(5)	(5)
Reclassification adjustment for amounts included in net income, net of tax of $2, $1, and $1, respectively	4	2	2
Total other comprehensive income (loss)	2	(3)	(3)
Comprehensive Income	$841	$808	$797

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

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STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2016, 2015, and 2014
Alabama Power Company 2016 Annual Report

	2016	2015	2014
	(in millions)		
Operating Activities:			
Net income	$839	$811	$800
Adjustments to reconcile net income			
to net cash provided from operating activities —			
Depreciation and amortization, total	844	780	724
Deferred income taxes	407	388	270
Allowance for equity funds used during construction	(28)	(60)	(49)
Pension, postretirement, and other employee benefits	(27)	20	(61)
Pension and postretirement funding	(133)	—	—
Other deferred charges – affiliated	(50)	—	—
Other, net	(25)	(5)	29
Changes in certain current assets and liabilities —			
-Receivables	94	(160)	(58)
-Fossil fuel stock	34	28	61
-Other current assets	(33)	12	(29)
-Accounts payable	73	3	157
-Accrued taxes	93	138	(199)
-Retail fuel cost over recovery	(162)	191	5
-Other current liabilities	23	(4)	59
Net cash provided from operating activities	1,949	2,142	1,709
Investing Activities:			
Property additions	(1,272)	(1,367)	(1,457)
Nuclear decommissioning trust fund purchases	(352)	(439)	(245)
Nuclear decommissioning trust fund sales	351	438	244
Cost of removal net of salvage	(94)	(71)	(77)
Change in construction payables	(37)	(15)	(10)
Other investing activities	(34)	(34)	(22)
Net cash used for investing activities	(1,438)	(1,488)	(1,567)
Financing Activities:			
Proceeds —			
Senior notes	400	975	400
Pollution control revenue bonds	—	80	254
Other long-term debt	45	—	—
Capital contributions from parent company	260	22	28
Redemptions and repurchases —			
Senior notes	(200)	(650)	—
Preferred and preference stock	—	(412)	—
Pollution control revenue bonds	—	(134)	(254)
Payment of common stock dividends	(765)	(571)	(550)
Other financing activities	(25)	(43)	(42)
Net cash used for financing activities	(285)	(733)	(164)
Net Change in Cash and Cash Equivalents	226	(79)	(22)
Cash and Cash Equivalents at Beginning of Year	194	273	295
Cash and Cash Equivalents at End of Year	$420	$194	$273

Supplemental Cash Flow Information:			
Cash paid (received) during the period for —			
Interest (net of $11, $22, and $18 capitalized, respectively)	$277	$250	$231
Income taxes (net of refunds)	(108)	121	436
Noncash transactions — accrued property additions at year-end	84	121	8

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

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BALANCE SHEETS
At December 31, 2016 and 2015
Alabama Power Company 2016 Annual Report

Assets	2016	2015
	(in millions)	
Current Assets:		
Cash and cash equivalents	$420	$194
Receivables —		
Customer accounts receivable	348	375
Unbilled revenues	146	119
Income taxes receivable, current	—	142
Other accounts and notes receivable	27	20
Affiliated	40	50
Accumulated provision for uncollectible accounts	(10)	(10)
Fossil fuel stock	205	239
Materials and supplies	435	398
Prepaid expenses	34	83
Other regulatory assets, current	149	182
Other current assets	11	9
Total current assets	1,805	1,801
Property, Plant, and Equipment:		
In service	26,031	24,750
Less accumulated provision for depreciation	9,112	8,736
Plant in service, net of depreciation	16,919	16,014
Nuclear fuel, at amortized cost	336	363
Construction work in progress	491	801
Total property, plant, and equipment	17,746	17,178
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	66	71
Nuclear decommissioning trusts, at fair value	792	737
Miscellaneous property and investments	112	96
Total other property and investments	970	904
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	525	522
Deferred under recovered regulatory clause revenues	150	99
Other regulatory assets, deferred	1,157	1,114
Other deferred charges and assets	163	103
Total deferred charges and other assets	1,995	1,838
Total Assets	$22,516	$21,721

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

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BALANCE SHEETS
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Liabilities and Stockholder's Equity	2016	2015
	(in millions)	
Current Liabilities:		
Securities due within one year	$561	$200
Accounts payable —		
Affiliated	297	278
Other	433	410
Customer deposits	88	88
Accrued taxes —		
Accrued income taxes	45	—
Other accrued taxes	42	38
Accrued interest	78	73
Accrued compensation	193	175
Other regulatory liabilities, current	85	240
Other current liabilities	76	93
Total current liabilities	1,898	1,595
Long-Term Debt (See accompanying statements)	6,535	6,654
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	4,654	4,241
Deferred credits related to income taxes	65	70
Accumulated deferred investment tax credits	110	118
Employee benefit obligations	300	388
Asset retirement obligations	1,503	1,448
Other cost of removal obligations	684	722
Other regulatory liabilities, deferred	100	136
Other deferred credits and liabilities	63	76
Total deferred credits and other liabilities	7,479	7,199
Total Liabilities	15,912	15,448
Redeemable Preferred Stock (See accompanying statements)	85	85
Preference Stock (See accompanying statements)	196	196
Common Stockholder's Equity (See accompanying statements)	6,323	5,992
Total Liabilities and Stockholder's Equity	$22,516	$21,721
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2016 and 2015
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	2016	2015	2016	2015
	(in millions)		(percent of total)	
Long-Term Debt:				
Long-term debt payable to affiliated trusts —				
Variable rate (3.95% at 1/1/17) due 2042	$206	$206		
Long-term notes payable —				
5.20% due 2016	—	200		
5.50% to 5.55% due 2017	525	525		
5.125% due 2019	200	200		
3.375% due 2020	250	250		
2.38% to 3.95% due 2021	220	200		
2.80% to 6.125% due 2022-2046	4,625	4,225		
Variable rates (1.87% to 2.10% at 1/1/17) due 2021	25	—		
Total long-term notes payable	5,845	5,600		
Other long-term debt —				
Pollution control revenue bonds —				
0.65% to 1.65% due 2034	207	287		
Variable rates (0.77% to 0.79% at 1/1/17) due 2017	36	36		
Variable rates (0.82% to 0.86% at 1/1/17) due 2021	65	65		
Variable rates (0.77% to 0.82% at 1/1/17) due 2024-2038	788	709		
Total other long-term debt	1,096	1,097		
Capitalized lease obligations	4	5		
Unamortized debt premium (discount), net	(9)	(9)		
Unamortized debt issuance expense	(46)	(45)		
Total long-term debt (annual interest requirement — $290 million)	7,096	6,854		
Less amount due within one year	561	200		
Long-term debt excluding amount due within one year	6,535	6,654	49.7 %	51.4 %
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 — 5.83%				
Authorized — 27,500,000 shares				
Outstanding — 1,520,000 shares: $25 stated value				
(annual dividend requirement — $4 million)	37	37		
Total redeemable preferred stock	85	85	0.7	0.7
Preference Stock:				
Authorized — 40,000,000 shares				
Outstanding — $1 par value — 6.45% to 6.50%				
— 8,000,000 shares (non-cumulative): $25 stated value				
(annual dividend requirement — $13 million)	196	196	1.5	1.5
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	2,613	2,341		
Retained earnings	2,518	2,461		
Accumulated other comprehensive loss	(30)	(32)		
Total common stockholder's equity	6,323	5,992	48.1	46.4
Total Capitalization	$13,139	$12,927	100.0%	100.0%

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

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STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2016, 2015, and 2014
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	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
	(in millions)					
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
Net income after dividends on preferred and preference stock	—	—	—	822	—	822
Capital contributions from parent company	—	—	272	—	—	272
Other comprehensive income (loss)	—	—	—	—	2	2
Cash dividends on common stock	—	—	—	(765)	—	(765)
Balance at December 31, 2016	31	$ 1,222	$2,613	$2,518	$ (30)	$6,323

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

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NOTES TO FINANCIAL STATEMENTS
Alabama Power Company 2016 Annual Report

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NOTES (continued)
Alabama Power Company 2016 Annual Report

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 the Company and three other traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), SCS, Southern LINC, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, PowerSecure, Inc. (PowerSecure) (as of May 9, 2016), and other direct and indirect subsidiaries. The traditional electric 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 electric service 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. Southern Company Gas distributes natural gas through utilities in seven states and is involved in several other complementary businesses including gas marketing services, wholesale gas services, and gas midstream operations. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. Southern LINC 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. PowerSecure is a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure.
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
In 2014, the FASB issued ASC 606, Revenue from Contracts with Customers, replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the guidance is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.
While the Company expects most of its revenue to be included in the scope of ASC 606, it has not fully completed its evaluation of such arrangements. The majority of the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term. For such arrangements, the Company generally expects that the revenue from contracts with these customers will continue to be equivalent to the electricity supplied and billed in that period (including unbilled revenues) and the adoption of ASC 606 will not result in a significant shift in the timing of revenue recognition for such sales.
The Company's ongoing evaluation of other revenue streams and related contracts includes longer term contractual commitments and unregulated sales to customers. Some revenue arrangements, such as certain PPAs and alternative revenue programs, are expected to be excluded from the scope of ASC 606 and therefore, be accounted for and presented separately from revenues under ASC 606 on the Company's financial statements. In addition, the power and utilities industry is currently addressing other specific industry issues, including the applicability of ASC 606 to contributions in aid of construction (CIAC). If final implementation guidance indicates CIAC will be accounted for

under ASC 606 and offsetting regulatory treatment is not permitted, it could have a material impact on the Company's financial statements.
The new standard is effective for interim and annual reporting periods beginning after December 15, 2017. The Company must select a transition method to be applied either retrospectively to each prior reporting period presented or retrospectively with a cumulative effect adjustment to retained earnings at the date of initial adoption. As the ultimate impact of the new standard has not yet been determined, the Company has not elected its transition method.
On February 25, 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842) (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition,

NOTES (continued)
Alabama Power Company 2016 Annual Report

measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company is currently evaluating the new standard and has not yet determined its ultimate impact; however, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.
On March 30, 2016, the FASB issued ASU No. 2016-09, Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting (ASU 2016-09). ASU 2016-09 changes the accounting for income taxes and the cash flow presentation for share-based payment award transactions effective for fiscal years beginning after December 15, 2016. The new guidance requires all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation to be recognized as income tax expense or benefit in the income statement. Previously, the Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities rather than net cash provided from financing activities on the statement of cash flows. The Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. The Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of the Company. See Notes 5, 8, and 12 for disclosures impacted by ASU 2016-09.
On October 24, 2016, the FASB issued ASU No. 2016-16, Income Taxes (Topic 740), Intra-Entity Transfers of Assets Other Than Inventory (ASU 2016-16). Current GAAP prohibits the recognition of current and deferred income taxes for an affiliate asset transfer until the asset has been sold to an outside party. ASU 2016-16 requires an entity to recognize the income tax consequences of an affiliate transfer of an asset other than inventory when the transfer occurs. ASU 2016-16 is effective for annual reporting periods beginning after December 15, 2017 and interim periods within those annual periods. The amendments will be applied on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. The Company is currently assessing the impact of the standard on its financial statements and has not yet determined its ultimate impact.

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 $460 million, $438 million, and $400 million during 2016, 2015, and 2014, 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 $249 million, $243 million, and $234 million during 2016, 2015, and 2014, 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 totaled $13 million in 2016, $11 million in 2015, and

$13 million in 2014. Mississippi Power also reimbursed the Company for any direct fuel purchases delivered from one of the Company's transfer facilities. There were no fuel purchases in 2016. Fuel purchases were $8 million and $34 million in 2015 and 2014, respectively. See Note 4 for additional information.

The Company has an agreement with Gulf Power under which the Company 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. Under a related tariff, the Company received $12 million in 2016, $14 million in 2015, and $12 million in 2014 and expects to recover a total of approximately $73 million from 2017 through 2023 from Gulf Power.

On September 1, 2016, Southern Company Gas acquired a 50% equity interest in Southern Natural Gas Company, L.L.C. (SNG). Prior to completion of the acquisition, SCS, as agent for the Company, had entered into a long-term interstate natural gas transportation agreement with SNG. The interstate transportation service provided to the Company by SNG pursuant to this

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agreement is governed by the terms and conditions of SNG's natural gas tariff and is subject to FERC regulation. For the period subsequent to Southern Company Gas' investment in SNG through December 31, 2016, transportation costs under this agreement were approximately $2 million.
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 2016, 2015, or 2014.
Also, see Note 4 for information regarding the Company's ownership in a PPA and a gas pipeline ownership agreement with SEGCO.
The traditional electric 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.

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Alabama Power Company 2016 Annual Report

Regulatory Assets and Liabilities

The Company is subject to accounting requirements 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:

	2016	2015	Note
	(in millions)		
Retiree benefit plans	$947	$903	(i,j)
Deferred income tax charges	526	522	(a,k)
Under/(over) recovered regulatory clause revenues	76	(97)	(d)
Nuclear outage	70	53	(d)
Remaining net book value of retired assets	69	76	(l)
Vacation pay	69	66	(c,j)
Loss on reacquired debt	68	75	(b)
Other regulatory assets	50	53	(f)
Asset retirement obligations	12	(40)	(a)
Fuel-hedging losses	1	55	(e,j)
Other cost of removal obligations	(684)	(722)	(a)
Natural disaster reserve	(69)	(75)	(h)
Deferred income tax credits	(65)	(70)	(a)
Other regulatory liabilities	(23)	(8)	(e,g)
Total regulatory assets (liabilities), net	$1,047	$791	

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 other cost of 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. See Note 3 under "Retail Regulatory Matters" for additional information.

(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 (to be recovered over the next 12 months), and other miscellaneous assets. Recorded as accepted by the Alabama PSC. Capitalized upon initialization of related construction projects, if applicable.

(g) Comprised of components including mine reclamation and remediation liabilities and fuel-hedging gains. Recorded as accepted by the Alabama PSC. Mine reclamation and remediation liabilities will be settled following completion of the related activities.

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

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

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

(k) Included in the deferred income tax charges are $16 million for 2016 and $17 million for 2015 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.

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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 and the Alabama PSC continuously monitor the under/over recovered balances. The Company 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 Compliance" 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.

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:

	2016	2015
	(in millions)	
Generation	$13,551	$12,820
Transmission	3,921	3,773
Distribution	6,707	6,432
General	1,840	1,713
Plant acquisition adjustment	12	12
Total plant in service	$26,031	$24,750

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.

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Depreciation and Amortization
Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.0% in 2016, 2.9% in 2015, and 3.3% in 2014. 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 2016, the Company submitted an updated depreciation study to the FERC and received authorization to use the recommended rates beginning January 2017. The study was also provided to the Alabama PSC. The revised rates will not have a significant impact on depreciation expense in 2017.
Asset Retirement Obligations and Other Costs of Removal
AROs 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 in April 2015 (CCR Rule), principally ash ponds. In addition, the Company has retirement obligations related to various landfill sites, underground storage tanks, asbestos removal related to ongoing repair and maintenance, 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, asbestos containing material within long-term assets not subject to ongoing repair and maintenance activities, 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:

	2016	2015
	(in millions)	
Balance at beginning of year	$1,448	$829
Liabilities incurred	5	402
Liabilities settled	(25)	(3)
Accretion	73	53
Cash flow revisions	32	167

Balance at end of year	$1,533	$1,448

The increase in liabilities incurred and cash flow revisions in 2016 and 2015 are primarily related to changes in ash pond closure strategy.

The cost estimates for AROs related to the CCR Rule are based on information as of December 31, 2016 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

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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 with respect to compliance activities, 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.

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, 2016, investment securities in the Funds totaled $790 million, consisting of equity securities of $552 million, debt securities of $208 million, and $30 million of other securities. 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. 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 $351 million, $438 million, and $244 million in 2016, 2015, and 2014, respectively, all of which were reinvested. For 2016, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $76 million, which included $34 million related to unrealized gains on securities held in the Funds at December 31, 2016. 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. 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 through 2040 as 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:

	2016	2015
	(in millions)	
External trust funds	$790	$734
Internal reserves	19	20

Total	$ 809	$ 754

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Site study cost is the estimate to decommission a facility as of the site study year. The estimated costs of decommissioning as of December 31, 2016 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

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, 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 8.4% in 2016, 8.7% in 2015, and 8.8% in 2014. AFUDC, net of income taxes, as a percent of net income after dividends on preferred and preference stock was 4.2% in 2016, 9.3% in 2015, and 7.9% in 2014.

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.

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Fuel Inventory
Fuel inventory includes the average cost of coal, natural gas, oil, transportation, and emissions allowances. Fuel is recorded 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") 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. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts that qualify as fair value hedges are marked to market through current period income and are recorded on a net basis in the statements of income. Cash flows from derivatives are classified on the statement of cash flows in the same category as the hedged item. See Note 11 for additional information regarding derivatives.
Beginning in 2016, the Company offsets fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2016.
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). On December 19, 2016, the Company voluntarily contributed $129 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2017. 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, 2017, no other postretirement trusts contributions are expected.

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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:	2016	2015	2014
Pension plans			
Discount rate – benefit obligations	4.67%	4.18%	5.02%
Discount rate – interest costs	3.90	4.18	5.02
Discount rate – service costs	5.07	4.49	5.02
Expected long-term return on plan assets	8.20	8.20	8.20
Annual salary increase	4.46	3.59	3.59
Other postretirement benefit plans			
Discount rate – benefit obligations	4.51%	4.04%	4.86%
Discount rate – interest costs	3.69	4.04	4.86
Discount rate – service costs	4.96	4.40	4.86
Expected long-term return on plan assets	6.83	7.17	7.34
Annual salary increase	4.46	3.59	3.59

Assumptions used to determine benefit obligations:	2016	2015
Pension plans		
Discount rate	4.44%	4.67%
Annual salary increase	4.46	4.46
Other postretirement benefit plans		
Discount rate	4.27%	4.51%
Annual salary increase	4.46	4.46

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of seven different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio.
An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2016 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate is Reached
Pre-65	6.50 %	4.50 %	2025
Post-65 medical	5.00	4.50	2025
Post-65 prescription	10.00	4.50	2025

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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, 2016 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$28	$ 24
Service and interest costs	1	1

Pension Plans

The total accumulated benefit obligation for the pension plans was $2.4 billion at December 31, 2016 and $2.3 billion at December 31, 2015. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2016 and 2015 were as follows:

	2016	2015
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$2,506	$2,592
Service cost	57	59
Interest cost	95	106
Benefits paid	(109)	(120)
Actuarial (gain) loss	114	(131)
Balance at end of year	2,663	2,506
Change in plan assets		
Fair value of plan assets at beginning of year	2,279	2,396
Actual return (loss) on plan assets	206	(9)
Employer contributions	141	12
Benefits paid	(109)	(120)
Fair value of plan assets at end of year	2,517	2,279
Accrued liability	$(146)	$(227)

At December 31, 2016, the projected benefit obligations for the qualified and non-qualified pension plans were $2.5 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, 2016 and 2015 related to the Company's pension plans consist of the following:

	2016	2015
	(in millions)	
Other regulatory assets, deferred	$870	$822
Other current liabilities	(12)	(11)
Employee benefit obligations	(134)	(216)

Presented below are the amounts included in regulatory assets at December 31, 2016 and 2015 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 2017.

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	2016	2015	Estimated Amortization in 2017
	(in millions)		
Prior service cost	$10	$6	$ 3
Net (gain) loss	860	816	42
Regulatory assets	$870	$822	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2016 and 2015 are presented in the following table:

	2016	2015
	(in millions)	
Regulatory assets:		
Beginning balance	$822	$827
Net (gain) loss	84	56
Change in prior service costs	7	—
Reclassification adjustments:		
Amortization of prior service costs	(3)	(6)
Amortization of net gain (loss)	(40)	(55)
Total reclassification adjustments	(43)	(61)
Total change	48	(5)
Ending balance	$870	$822

Components of net periodic pension cost were as follows:

	2016	2015	2014
	(in millions)		
Service cost	$57	$59	$48
Interest cost	95	106	103
Expected return on plan assets	(184)	(178)	(168)
Recognized net (gain) loss	40	55	31
Net amortization	3	6	7
Net periodic pension cost	$11	$48	$21

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.

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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, 2016, estimated benefit payments were as follows:

	Benefit Payments (in millions)
2017	$ 122
2018	127
2019	132
2020	137
2021	142
2022 to 2026	777

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2016 and 2015 were as follows:

	2016	2015
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$505	$503
Service cost	5	6
Interest cost	18	20
Benefits paid	(28)	(27)
Actuarial (gain) loss	(1)	(7)
Plan amendment	—	7
Retiree drug subsidy	2	3
Balance at end of year	501	505
Change in plan assets		
Fair value of plan assets at beginning of year	363	392
Actual return (loss) on plan assets	23	(6)
Employer contributions	7	1
Benefits paid	(26)	(24)
Fair value of plan assets at end of year	367	363
Accrued liability	$(134)	$(142)

Amounts recognized in the balance sheets at December 31, 2016 and 2015 related to the Company's other postretirement benefit plans consist of the following:

	2016	2015
	(in millions)	
Other regulatory assets, deferred	$86	$95
Other regulatory liabilities, deferred	(10)	(13)
Employee benefit obligations	(134)	(142)

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Presented below are the amounts included in net regulatory assets (liabilities) at December 31, 2016 and 2015 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 2017.

	2016	2015	Estimated Amortization in 2017
	(in millions)		
Prior service cost	$15	$ 19	$ 4
Net (gain) loss	61	63	1
Net regulatory assets	$76	$ 82	

The changes in the balance of net regulatory assets (liabilities) related to the other postretirement benefit plans for the plan years ended December 31, 2016 and 2015 are presented in the following table:

	2016	2015
	(in millions)	
Net regulatory assets (liabilities):		
Beginning balance	$82	$54
Net (gain) loss	—	25
Change in prior service costs	—	8
Reclassification adjustments:		
Amortization of prior service costs	(4)	(3)
Amortization of net gain (loss)	(2)	(2)
Total reclassification adjustments	(6)	(5)
Total change	(6)	28
Ending balance	$76	$82

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

	2016	2015	2014
	(in millions)		
Service cost	$5	$ 6	$ 5
Interest cost	18	20	20
Expected return on plan assets	(25)	(26)	(25)
Net amortization	6	5	4
Net periodic postretirement benefit cost	$4	$ 5	$ 4

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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)		
2017	$32	$ (3)	$ 29
2018	33	(3)	30
2019	34	(4)	30
2020	35	(4)	31
2021	36	(4)	32
2022 to 2026	183	(22)	161

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, 2016 and 2015, along with the targeted mix of assets for each plan, is presented below:

	Target	2016	2015
Pension plan assets:			
Domestic equity	26 %	29 %	30 %
International equity	25	22	23
Fixed income	23	29	23
Special situations	3	2	2
Real estate investments	14	13	16
Private equity	9	5	6
Total	100 %	100%	100%
Other postretirement benefit plan assets:			
Domestic equity	46 %	44 %	45 %
International equity	22	20	20
Domestic fixed income	24	29	27
Special situations	1	1	1
Real estate investments	4	4	5
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, 2016 and 2015. 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, private equity, and special situations investments. Investments in real estate, private equity, and special situations are generally classified as Net Asset Value as a Practical Expedient, since the underlying assets typically do not have publicly available observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. Techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, discounted cash flow analysis, prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals. The fair value of partnerships is determined by aggregating the value of the underlying assets less liabilities.

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The fair values of pension plan assets as of December 31, 2016 and 2015 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. For 2015, investments in special situations were presented in the table below based on the nature of the investment.

	Fair Value Measurements Using				
	Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs	Net Asset Value as a Practical Expedient	
As of December 31, 2016:	(Level 1)	(Level 2)	(Level 3)	(NAV)	Total
	(in millions)				
Assets:					
Domestic equity(*)	$477	$ 220	$ —	$ —	$697
International equity(*)	292	264	—	—	556
Fixed income:					
U.S. Treasury, government, and agency bonds	—	140	—	—	140
Mortgage- and asset-backed securities	—	3	—	—	3
Corporate bonds	—	235	—	—	235
Pooled funds	—	124	—	—	124
Cash equivalents and other	236	1	—	—	237
Real estate investments	74	—	—	274	348
Special situations	—	—	—	43	43
Private equity	—	—	—	130	130
Total	$1,079	$ 987	$ —	$ 447	$2,513

(*) 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, 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.

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The fair values of other postretirement benefit plan assets as of December 31, 2016 and 2015 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. For 2015, investments in special situations were presented in the table below based on the nature of the investment.

	Fair Value Measurements Using				
	Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs	Net Asset Value as a Practical Expedient	
As of December 31, 2016:	(Level 1)	(Level 2)	(Level 3)	(NAV)	Total
	(in millions)				
Assets:					
Domestic equity(*)	$51	$ 10	$ —	$ —	$61
International equity(*)	13	12	—	—	25
Fixed income:					
U.S. Treasury, government, and agency bonds	—	7	—	—	7
Mortgage- and asset-backed securities	—	—	—	—	—
Corporate bonds	—	10	—	—	10
Pooled funds	—	5	—	—	5
Cash equivalents and other	14	—	—	—	14
Trust-owned life insurance	—	220	—	—	220
Real estate investments	4	—	—	12	16
Special situations	—	—	—	2	2
Private equity	—	—	—	6	6
Total	$82	$ 264	$ —	$ 20	$366

(*) 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.

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	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(*)	$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.

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 2016, 2015, and 2014 were $23 million, $22 million, and $21 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 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. In March 2015, the Company recovered approximately $26 million, which was applied to reduce the cost of service for the benefit of customers.

In 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, 2016 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 electric operating companies (including the Company) and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In April 2015, the FERC issued an order finding that the traditional electric 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 electric operating companies and in some adjacent areas. The FERC directed the traditional electric 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 electric operating companies (including the Company) and Southern Power filed a request for rehearing in May 2015 and in June 2015 filed their response with the FERC.

On December 9, 2016, the traditional electric operating companies (including the Company) and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' (including the Company's) and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies (including the Company) and in some adjacent areas. The traditional electric operating companies (including the Company) and Southern Power expect to make a compliance filing within 30 days accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.

The ultimate outcome of these matters 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% with an adjusting point of 5.98% and 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. 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, the excess will be refunded to customers unless otherwise directed by the Alabama PSC; however, there is no provision for additional customer billings should the actual retail return fall below the WCE range.

On December 1, 2016, the Company made its required annual Rate RSE submission to the Alabama PSC of projected data for calendar year 2017. The Rate RSE adjustment was an increase of 4.48%, or $245 million annually, effective January 1, 2017 and includes the performance based adder of 0.07%. Under the terms of Rate RSE, the maximum increase for 2018 cannot exceed 3.52%.

As of December 31, 2016, the 2016 retail return exceeded the allowed WCE range; therefore, the Company established a $73 million Rate RSE refund liability. In accordance with an order issued on February 14, 2017 by the Alabama PSC, the Company was directed to apply the full amount of the refund to reduce the under recovered balance of Rate CNP PPA.

Rate CNP PPA

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 8, 2016, 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, 2016 through March 31, 2017. No adjustment to Rate CNP PPA is expected in 2017. As of December 31, 2016 and 2015, the Company had an under recovered certificated PPA balance of $142 million and $99 million, respectively, which is included in deferred under recovered regulatory clause revenues in the balance sheet.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, the Company was authorized to eliminate the under recovered balance in Rate CNP PPA at December 31, 2016, which totaled approximately $142 million. As discussed herein under "Rate RSE," the Company will utilize the full amount of its $73 million Rate RSE refund liability to reduce the amount of the Rate CNP PPA under recovery and will reclassify the remaining $69 million to a separate regulatory asset. The amortization of the new regulatory asset through Rate RSE will begin concurrently with the effective date of the Company's next depreciation study, which is expected to occur within the next three to five years. The Company's current depreciation study became effective January 1, 2017.

Rate CNP Compliance

Rate CNP Compliance allows for the recovery of the Company's retail costs associated with laws, regulations, and other such mandates directed at the utility industry involving the environment, security, reliability, safety, sustainability, or similar considerations impacting the Company's facilities or operations. 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. Revenues for Rate CNP Compliance, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. Changes in compliance related operations and maintenance expenses and depreciation generally will have no effect on net income.

On December 6, 2016, the Alabama PSC issued a consent order that the Company leave in effect for 2017 the factors associated with the Company's compliance costs for the year 2016. As stated in the consent order, any under-collected amount for prior years will be deemed recovered before the recovery of any current year amounts. Any under recovered amounts associated with 2017 will be reflected in the 2018 filing. As of December 31, 2016, the Company had a deferred under recovered regulatory clause revenues balance of $9 million.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, the Company is authorized to classify any under recovered balance in Rate CNP Compliance up to approximately $36 million to a separate regulatory asset. The amortization of the new regulatory asset through Rate RSE will begin concurrently with the effective date of the Company's next depreciation study, which is expected to occur within the next three to five years. The Company's current depreciation study became effective January 1, 2017.

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

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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 2015, the Alabama PSC issued a consent order that the Company decrease the Rate ECR factor from 2.681 cents per KWH to 2.030 cents per KWH.

On December 6, 2016, the Alabama PSC approved a decrease in the Company's Rate ECR factor from 2.030 to 2.015 cents per KWH, equal to 0.15%, or $8 million annually, based upon projected billings, effective January 1, 2017. The rate will return to 5.910 cents per KWH in 2018 absent a further order from the Alabama PSC.

At December 31, 2016 and 2015, the Company's over recovered fuel costs totaled $76 million and $238 million, respectively, and are included in other regulatory liabilities, current. 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.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, the Company is authorized to classify any under recovered balance in Rate ECR up to approximately $36 million to a separate regulatory asset. The amortization of the new regulatory asset through Rate RSE will begin concurrently with the effective date of the Company's next depreciation study, which is expected to occur within the next three to five years. The Company's current depreciation study became effective January 1, 2017.

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. No such accruals were recorded or designated in any period presented.

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. In April 2016, as part of its environmental compliance strategy, the Company ceased using coal at Plant Greene County Units 1 and 2 (300 MWs representing the Company's ownership interest) and began operating Units 1 and 2 solely on natural gas in June 2016 and July 2016, respectively.

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 units' remaining useful lives, as established prior to the decision for retirement; therefore, these decisions associated with coal operations had no significant impact on the Company's financial statements.

Cost of Removal Accounting Order

In accordance with an accounting order issued by the Alabama PSC, in 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 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 $55 million in 2016, $76 million in 2015, and $84 million in 2014 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, 2016, the capitalization of SEGCO consisted of $108 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 $38 million. SEGCO paid $24 million of dividends in 2016 compared to an immaterial amount in 2015 and 2014, 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 became 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 an associated 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 an associated gas pipeline, the Company's percentage ownership and investment in jointly-owned generating plants at December 31, 2016 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)]	$168	$ 66	$ 1
Plant Miller Units 1 and 2	1,320	91.84 % [(2)]	1,657	587	23

(1) Jointly owned with an affiliate, Mississippi Power.
(2) Jointly owned with PowerSouth Energy Cooperative, Inc.

The Company has contracted to operate and maintain its 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

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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:

	2016	2015	2014
	(in millions)		
Federal —			
Current	$103	$110	$198
Deferred	339	320	225
	442	430	423
State —			
Current	20	8	44
Deferred	69	68	45
	89	76	89
Total	$531	$506	$512

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:

	2016	2015
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation	$4,307	$3,917
Property basis differences	456	456
Premium on reacquired debt	26	28
Employee benefit obligations	201	200
Regulatory assets associated with employee benefit obligations	393	375
Asset retirement obligations	289	289
Regulatory assets associated with asset retirement obligations	347	312
Other	179	175
Total	6,198	5,752
Deferred tax assets —		
Federal effect of state deferred taxes	266	242
Unbilled fuel revenue	36	39
Storm reserve	21	23
Employee benefit obligations	427	407
Other comprehensive losses	19	20
Asset retirement obligations	636	600
Other	139	180
Total	1,544	1,511
Accumulated deferred income taxes, net	$4,654	$4,241

The application of bonus depreciation provisions in current tax law significantly increased deferred tax liabilities related to accelerated depreciation in 2016 and 2015.

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At December 31, 2016, the tax-related regulatory assets to be recovered from customers were $526 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, 2016, the tax-related regulatory liabilities to be credited to customers were $65 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 annually in 2016, 2015, and 2014. At December 31, 2016, 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:

	2016	2015	2014
Federal statutory rate	35.0%	35.0%	35.0%
State income tax, net of federal deduction	4.2	3.8	4.4
Non-deductible book depreciation	1.0	1.2	1.1
AFUDC equity	(0.7)	(1.6)	(1.3)
Other	(0.7)	—	(0.2)
Effective income tax rate	38.8%	38.4%	39.0%

On March 30, 2016, the FASB issued ASU 2016-09, which changes the accounting for income taxes for share-based payment award transactions. Entities are required to recognize all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation as income tax expense or benefit in the income statement. The adoption of ASU 2016-09 did not have a material impact on the Company's overall effective tax rate. See Note 1 under "Recently Issued Accounting Standards" for additional information.

Unrecognized Tax Benefits

The Company has no material unrecognized tax benefits for the periods presented. 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, 2014, and 2015 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, 2016 and 2015, 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, 2016 and 2015, 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.

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Securities Due Within One Year

At December 31, 2016 and 2015, the Company had $561 million and $200 million, respectively, of senior notes and pollution control revenue bonds due within one year.

Maturities through 2021 applicable to total long-term debt are as follows: $561 million in 2017; $200 million in 2019; $250 million in 2020; and $310 million in 2021. There are no material scheduled maturities in 2018.

Bank Term Loans

In March 2016, the Company entered into three bank term loan agreements with maturity dates of March 2021, in an aggregate principal amount of $45 million, one of which bears interest at 2.38% per annum and two of which bear interest based on three-month LIBOR.

These bank loans have covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of calculating these covenants, any long-term notes payable to affiliated trusts are excluded from debt but included in capitalization. At December 31, 2016, the Company was in compliance with its debt limits.

Pollution Control Revenue Bonds

Pollution control revenue bond 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 2016.

The Company had $1.1 billion of tax-exempt pollution control revenue bond obligations outstanding at each of December 31, 2016 and 2015, including pollution control revenue bonds due within one year.

Senior Notes

In January 2016, 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 corporate purposes, including the Company's continuous construction program.

At December 31, 2016 and 2015, the Company had $5.8 billion and $5.6 billion of senior notes outstanding, respectively, including senior notes due within one year. As of December 31, 2016, the Company did not have any outstanding secured debt.

Subsequent to December 31, 2016, the Company repaid at maturity $200 million aggregate principal amount of its Series 2007A 5.55% Senior Notes due February 1, 2017.

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.

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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. The Company's outstanding preference stock is 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. 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
6.45% Preference Stock	$25	6,000,000	Stated Capital(*)
6.50% Preference Stock	$25	2,000,000	Stated Capital(*)

(*) Also includes a make-whole premium prior to October 1, 2017

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, 2016 and 2014 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, 2016, committed credit arrangements with banks were as follows:

Expires					Expires Within One Year	
2017	2018	2020	Total	Unused	Term Out	No Term Out
(in millions)			(in millions)		(in millions)	
$35	$500	$800	$1,335	$1,335	$ —	$ 35

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 level 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. At December 31, 2016, the Company was in compliance with the debt limit covenants.

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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 programs. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support was $890 million as of December 31, 2016. In addition, at December 31, 2016, the Company had $87 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, 2016 and 2015, there was no short-term debt outstanding. At December 31, 2016, 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 2016, 2015, and 2014, the Company incurred fuel expense of $1.3 billion, $1.3 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 $42 million, $38 million, and $37 million for 2016, 2015, and 2014, respectively. Total estimated minimum long-term obligations at December 31, 2016 were as follows:

	Operating Lease PPAs (in millions)
2017	$ 40
2018	41
2019	43
2020	44
2021	46
2022	47
Total commitments	$ 261

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 electric operating companies and Southern Power. Under these agreements, each of the traditional electric 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 electric 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 under these agreements was $18 million in 2016, $19 million in 2015, and $18 million in 2014. Of these amounts, $14 million, $13 million, and $14 million for 2016, 2015, and 2014, respectively, relate to the railcar leases and was recovered through the Company's Rate ECR. As of December 31, 2016, estimated minimum lease payments under operating leases were as follows:

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	Minimum Lease Payments		
	Railcars	Vehicles & Other	Total
	(in millions)		
2017	$ 10	$ 4	$ 14
2018	7	3	10
2019	7	3	10
2020	6	2	8
2021	6	2	8
2022 and thereafter	9	1	10
Total	$ 45	$ 15	$ 60

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 $12 million in 2023. There are no obligations under these leases through 2021. 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 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 primarily in the form of Southern Company 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, 2016, there were 865 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.

The weighted average grant-date fair value of stock options granted during 2014 derived using the Black-Scholes stock option pricing model was $2.20.

The compensation cost related to the grant of Southern Company stock options to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. Compensation cost and related tax benefits recognized in the Company's financial statements were not material for any year presented. As of December 31, 2016, 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, 2016, 2015, and 2014 was $21 million, $8 million, and $21 million, respectively. No cash proceeds are received by the Company upon the exercise of stock options. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $8 million, $3 million, and $8 million for the years ended December 31, 2016, 2015, and 2014, respectively. Prior to the adoption of ASU 2016-09, the excess tax benefits related to the exercise of stock options were recognized in the Company's financial statements with a credit to equity. Upon the adoption of ASU 2016-09, beginning in 2016, all tax benefits related to the exercise of stock options are recognized in income. As of December 31, 2016, the aggregate intrinsic value for the options outstanding and options exercisable was $30 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. 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, 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, 2016, 2015, and 2014, employees of the Company were granted performance share units of 249,065, 214,709, and 176,070, respectively. The weighted average grant-date fair value of TSR-based performance share units granted during 2016, 2015, and 2014, 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 $45.15, $46.42, and $37.54, respectively. The weighted average grant-date fair value of both EPS-based and ROE-based performance share units granted during 2016 and 2015 was $48.86 and $47.78, respectively.

For the years ended December 31, 2016, 2015, and 2014, total compensation cost for performance share units recognized in income was $15 million, $13 million, and $5 million, respectively, with the related tax benefit also recognized in income of $6 million, $5 million, and $2 million, respectively. The compensation cost related to the grant of Southern Company performance share units to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2016, $3 million of total unrecognized compensation cost related to performance share award units will be recognized over a weighted-average period of approximately 22 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 $13.4 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 maximum annual assessments for the Company as of December 31, 2016 under the NEIL policies would be $53 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.

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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, 2016, 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				
	Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs	Net Asset Value as a Practical Expedient	
As of December 31, 2016:	(Level 1)	(Level 2)	(Level 3)	(NAV)	Total
	(in millions)				
Assets:					
Energy-related derivatives	$—	$ 20	$ —	$ —	$20
Nuclear decommissioning trusts:(*)					
Domestic equity	385	72	—	—	457
Foreign equity	48	47	—	—	95
U.S. Treasury and government agency securities	—	21	—	—	21
Corporate bonds	22	146	—	—	168
Mortgage and asset backed securities	—	19	—	—	19
Private equity	—	—	—	20	20
Other	—	10	—	—	10
Cash equivalents	262	—	—	—	262
Total	$717	$ 335	$ —	$ 20	$1,072
Liabilities:					
Energy-related derivatives	$—	$ 9	$ —	$ —	$9

(*) 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.

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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				
	Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs	Net Asset Value as a Practical Expedient	
As of December 31, 2015:	(Level 1)	(Level 2)	(Level 3)	(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.

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 reflects 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.

As of December 31, 2016 and 2015, 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, 2016	$ 20	$ 25	Not Applicable	Not Applicable
As of December 31, 2015	$ 17	$ 28	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, 2016 and 2015, 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:		
2016	$7,092	$7,544
2015	$6,849	$7,192

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, including 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 net 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 energy-related commodity prices. 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.

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- 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, 2016, the net volume of energy-related derivative contracts for natural gas positions totaled 74 million mmBtu for the Company, with the longest hedge date of 2020 over which it is hedging its exposure to the variability in future cash flows for forecasted transactions.

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, 2016, there were no interest rate derivatives outstanding.

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2017 are $6 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2035.

Derivative Financial Statement Presentation and Amounts

The Company enters into energy-related and interest rate derivative contracts that may contain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. At December 31, 2016, fair value amounts of derivative assets and liabilities on the balance sheets are presented net to the extent that there are netting arrangements or similar agreements with the counterparties. At December 31, 2015, the fair value amounts of derivative instruments were presented gross on the balance sheets.

At December 31, 2016 and 2015, the fair value of energy-related derivatives and interest rate derivatives was reflected on the balance sheets as follows:

Derivative Category and Balance Sheet Location	2016 Assets	2016 Liabilities	2015 Assets	2015 Liabilities
	(in millions)			
Derivatives designated as hedging instruments for regulatory purposes				
Energy-related derivatives:				
Other current assets/Other current liabilities	$13	$ 5	$1	$ 40
Other deferred charges and assets/Other deferred credits and liabilities	7	4	—	15
Total derivatives designated as hedging instruments for regulatory purposes	$20	$ 9	$1	$ 55
Derivatives designated as hedging instruments in cash flow hedges				
Interest rate derivatives:				
Other current assets/Other current liabilities	$—	$ —	$—	$ 15
Gross amounts recognized	$20	$ 9	$1	$ 70
Gross amounts offset	$(8)	$ (8)	$(1)	$ (1)
Net amounts recognized in the Balance Sheets(*)	$12	$ 1	$—	$ 69

(*) At December 31, 2015, the fair value amounts for derivative contracts subject to netting arrangements were presented gross on the balance sheet.

Energy-related derivatives not designated as hedging instruments were immaterial on the balance sheets for 2016 and 2015.

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NOTES (continued)
Alabama Power Company 2016 Annual Report

At December 31, 2016 and 2015, the pre-tax effect of unrealized derivative gains (losses) arising from energy-related derivatives designated as regulatory hedging instruments and deferred were as follows:

Derivative Category	Unrealized Losses Balance Sheet Location	2016	2015	Unrealized Gains Balance Sheet Location	2016	2015
		(in millions)			(in millions)	
Energy-related derivatives:(*)	Other regulatory assets, current	$(1)	$(40)	Other current liabilities	$ 8	$ 1
	Other regulatory assets, deferred	—	(15)	Other regulatory liabilities, deferred	4	—
Total energy-related derivative gains (losses)		$(1)	$(55)		$ 12	$ 1

(*) At December 31, 2016, the unrealized gains and losses for derivative contracts subject to netting arrangements were presented net on the balance sheet. At December 31, 2015, the unrealized gains and losses for derivative contracts were presented gross on the balance sheet.

For the years ended December 31, 2016, 2015, and 2014, 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	2016	2015	2014	Statements of Income Location	2016	2015	2014
	(in millions)				(in millions)		
Interest rate derivatives	$ (3)	$ (7)	$ (8)	Interest expense, net of amounts capitalized	$(6)	$(3)	$(3)

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

The pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was not material for any year presented.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies.

At December 31, 2016, the fair value of derivative liabilities with contingent features, including 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 because of joint and several liability features underlying these derivatives, was immaterial.

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 maintains accounts with certain regional transmission organizations to facilitate financial derivative transactions. Based on the value of the positions in these accounts and the associated margin requirements, the Company may be required to post collateral. At December 31, 2016, the Company's collateral posted in these accounts was not material.

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.

NOTES (continued)
Alabama Power Company 2016 Annual Report

12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2016 and 2015 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
	(in millions)		
March 2016	$1,331	$ 333	$ 156
June 2016	1,444	430	213
September 2016	1,785	650	351
December 2016	1,329	252	102
March 2015	$1,401	$ 346	$ 169
June 2015	1,455	398	200
September 2015	1,695	555	295
December 2015	1,217	264	121

In accordance with the adoption of ASU 2016-09 (see Note 1 under "Recently Issued Accounting Standards"), previously reported amounts for income tax expense were reduced by $2 million in the third quarter 2016, $2 million in the second quarter 2016, and $1 million in the first quarter 2016.
The Company's business is influenced by seasonal weather conditions.

SELECTED FINANCIAL AND OPERATING DATA 2012-2016
Alabama Power Company 2016 Annual Report

	2016	2015	2014	2013	2012
Operating Revenues (in millions)	$ 5,889	$ 5,768	$ 5,942	$ 5,618	$ 5,520
Net Income After Dividends on Preferred and Preference Stock (in millions)	$ 822	$ 785	$ 761	$ 712	$ 704
Cash Dividends on Common Stock (in millions)	$ 765	$ 571	$ 550	$ 644	$ 684
Return on Average Common Equity (percent)	13.34	13.37	13.52	13.07	13.10
Total Assets (in millions)[(a)(b)]	$ 22,516	$ 21,721	$ 20,493	$ 19,185	$ 18,647
Gross Property Additions (in millions)	$ 1,338	$ 1,492	$ 1,543	$ 1,204	$ 940
Capitalization (in millions):					
Common stock equity	$ 6,323	$ 5,992	$ 5,752	$ 5,502	$ 5,398
Preference stock	196	196	343	343	343
Redeemable preferred stock	85	85	342	342	342
Long-term debt[(a)]	6,535	6,654	6,137	6,195	5,890
Total (excluding amounts due within one year)	$ 13,139	$ 12,927	$ 12,574	$ 12,382	$ 11,973
Capitalization Ratios (percent):					
Common stock equity	48.1	46.4	45.8	44.4	45.1
Preference stock	1.5	1.5	2.7	2.8	2.9
Redeemable preferred stock	0.7	0.7	2.7	2.7	2.9
Long-term debt[(a)]	49.7	51.4	48.8	50.1	49.1
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	1,262,752	1,253,875	1,247,061	1,241,998	1,237,730
Commercial	199,146	197,920	197,082	196,209	196,177
Industrial	6,090	6,056	6,032	5,851	5,839
Other	762	757	753	751	748
Total	1,468,750	1,458,608	1,450,928	1,444,809	1,440,494
Employees (year-end)	6,805	6,986	6,935	6,896	6,778

(a) A reclassification of debt issuance costs from Total Assets to Long-term debt of $40 million, $38 million, and $39 million is reflected for years 2014, 2013, and 2012, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(b) A reclassification of deferred tax assets from Total Assets of $20 million, $27 million, and $27 million is reflected for years 2014, 2013, and 2012, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

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SELECTED FINANCIAL AND OPERATING DATA 2012-2016 (continued)
Alabama Power Company 2016 Annual Report

	2016	2015	2014	2013	2012
Operating Revenues (in millions):					
Residential	$2,322	$2,207	$2,209	$2,079	$2,068
Commercial	1,627	1,564	1,533	1,477	1,491
Industrial	1,416	1,436	1,480	1,369	1,346
Other	(43)	27	27	27	28
Total retail	5,322	5,234	5,249	4,952	4,933
Wholesale — non-affiliates	283	241	281	248	277
Wholesale — affiliates	69	84	189	212	111
Total revenues from sales of electricity	5,674	5,559	5,719	5,412	5,321
Other revenues	215	209	223	206	199
Total	$5,889	$5,768	$5,942	$5,618	$5,520
Kilowatt-Hour Sales (in millions):					
Residential	18,343	18,082	18,726	17,920	17,612
Commercial	14,091	14,102	14,118	13,892	13,963
Industrial	22,310	23,380	23,799	22,904	22,158
Other	208	201	211	211	214
Total retail	54,952	55,765	56,854	54,927	53,947
Wholesale — non-affiliates	3,597	3,567	3,588	3,711	4,196
Wholesale — affiliates	5,324	4,515	6,713	7,672	4,279
Total	63,873	63,847	67,155	66,310	62,422
Average Revenue Per Kilowatt-Hour (cents):					
Residential	12.66	12.21	11.80	11.60	11.74
Commercial	11.55	11.09	10.86	10.63	10.68
Industrial	6.35	6.14	6.22	5.98	6.07
Total retail	9.68	9.39	9.23	9.02	9.14
Wholesale	3.95	4.02	4.56	4.04	4.58
Total sales	8.88	8.71	8.52	8.16	8.52
Residential Average Annual Kilowatt-Hour Use Per Customer	14,568	14,454	15,051	14,451	14,252
Residential Average Annual Revenue Per Customer	$1,844	$1,764	$1,775	$1,676	$1,674
Plant Nameplate Capacity Ratings (year-end) (megawatts)	11,797	11,797	12,222	12,222	12,222
Maximum Peak-Hour Demand (megawatts):					
Winter	10,282	12,162	11,761	9,347	10,285
Summer	10,932	11,292	11,054	10,692	11,096
Annual Load Factor (percent)	63.5	58.4	61.4	64.9	61.3
Plant Availability (percent):					
Fossil-steam	83.0	81.5	82.5	87.3	88.6
Nuclear	88.0	92.1	93.3	90.7	94.5
Source of Energy Supply (percent):					
Coal	47.1	49.1	49.0	50.0	48.2
Nuclear	20.3	21.3	20.7	20.3	22.6
Hydro	4.8	5.6	5.5	8.1	4.1

Gas	17.1	14.6	15.4	15.7	16.8
Purchased power —					
From non-affiliates	4.8	4.4	3.6	2.9	2.0
From affiliates	5.9	5.0	5.8	3.0	6.3
Total	100.0	100.0	100.0	100.0	100.0

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Georgia Power Company 2016 Annual Report

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

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2016.

/s/ W. Paul Bowers
W. Paul Bowers
Chairman, President, and Chief Executive Officer
/s/ W. Ron Hinson
W. Ron Hinson
Executive Vice President, Chief Financial Officer, and Treasurer
February 21, 2017

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Georgia Power Company

We have audited the accompanying balance sheets and statements of capitalization of Georgia Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2016 and 2015, 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, 2016. 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 II-263 to II-310) present fairly, in all material respects, the financial position of Georgia Power Company as of December 31, 2016 and 2015, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 21, 2017

DEFINITIONS

Term	Meaning
2013 ARP	Alternative Rate Plan approved by the Georgia PSC in 2013 for Georgia Power for the years 2014 through 2016 and subsequently extended through 2019
AFUDC	Allowance for funds used during construction
Alabama Power	Alabama Power Company
ARO	Asset retirement obligation
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
CCR	Coal combustion residuals
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
CWIP	Construction work in progress
DOE	U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FFB	Federal Financing Bank
GAAP	U.S. generally accepted accounting principles
Gulf Power	Gulf Power Company
IRS	Internal Revenue Service
ITC	Investment tax credit
KWH	Kilowatt-hour
LIBOR	London Interbank Offered Rate
Mississippi Power	Mississippi Power Company
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MW	Megawatt
NCCR	Nuclear Construction Cost Recovery
NRC	U.S. Nuclear Regulatory Commission
OCI	Other comprehensive income
Plant Vogtle Units 3 and 4	Two new nuclear generating units under construction at Plant Vogtle
power pool	The operating arrangement whereby the integrated generating resources of the traditional electric operating companies and Southern Power (excluding subsidiaries) are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power purchase agreement
PSC	Public Service Commission
PTC	Production tax credit
ROE	Return on equity
S&P	S&P Global Ratings, a division of S&P Global 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

DEFINITIONS
(continued)

Term	Meaning
Southern Company Gas	Southern Company Gas (formerly known as AGL Resources Inc.) and its subsidiaries
Southern Company system	Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), SEGCO, Southern Nuclear, SCS, Southern LINC, PowerSecure, Inc. (as of May 9, 2016), and other subsidiaries
Southern LINC	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
traditional electric operating companies	Alabama Power, Georgia Power Company, Gulf Power, and Mississippi Power

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Georgia Power Company 2016 Annual Report
OVERVIEW
Business Activities
Georgia Power Company (the Company) operates as a vertically integrated utility providing electric service to retail customers within its traditional service territory located within the State of Georgia and to wholesale customers in the Southeast.
Many factors affect the opportunities, challenges, and risks of the Company's business of providing electric service. 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, stringent environmental standards, reliability, fuel, capital expenditures, and restoration following major storms. In addition, construction continues on Plant Vogtle Units 3 and 4. The Company will own a 45.7% interest in these two nuclear generating units to increase its generation diversity and meet future supply needs. The Company has various regulatory mechanisms that operate to address cost recovery. Effectively operating pursuant to these regulatory mechanisms and appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Nuclear Construction" herein for additional information on Plant Vogtle Units 3 and 4.
Pursuant to the terms and conditions of a settlement agreement related to Southern Company's acquisition of Southern Company Gas approved by the Georgia PSC on April 14, 2016, the Company's 2013 ARP will continue in effect until December 31, 2019, and the Company will be required to file its next base rate case by July 1, 2019. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Rate Plans" herein for additional information.
The Company continues to focus on several key performance indicators, including, but not limited to, customer satisfaction, plant availability, system reliability, the execution of major construction projects, and net income after dividends on preferred and preference stock. The Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys to evaluate the Company's results and generally targets the top quartile of these surveys in measuring performance.
See RESULTS OF OPERATIONS herein for information on the Company's financial performance.
Earnings
The Company's 2016 net income after dividends on preferred and preference stock was $1.3 billion, representing a $70 million, or 5.6%, increase over the previous year. The increase was due primarily to an increase in base retail revenues effective January 1, 2016, as authorized by the Georgia PSC, the 2015 correction of an error affecting billings since 2013 to a small number of large commercial and industrial customers, and higher retail revenues in the third quarter 2016 due to warmer weather as compared to the corresponding period in 2015, partially offset by an adjustment for an expected refund to retail customers as a result of the Company's retail ROE exceeding the allowed retail ROE range under the 2013 ARP during 2016. Higher non-fuel operating expenses also partially offset the revenue increase.
The Company's 2015 net income after dividends on preferred and preference stock was $1.3 billion, representing a $35 million, or 2.9%, increase over the previous year. The increase was due primarily to an increase in base retail revenues effective January 1, 2015, as authorized by the Georgia PSC, and lower non-fuel operations and maintenance expenses, partially offset by the 2015 correction of an error affecting billings since 2013 to a small number of large commercial and industrial customers.
See Note 1 to the financial statements under "General" and FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Rate Plans" herein for additional information related to the 2015 error correction and the 2016 expected refund to retail customers, respectively.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2016 Annual Report

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

	Amount	Increase (Decrease) from Prior Year	
	2016	2016	2015
	(in millions)		
Operating revenues	$8,383	$ 57	$ (662)
Fuel	1,807	(226)	(514)
Purchased power	879	15	(124)
Other operations and maintenance	1,960	116	(58)
Depreciation and amortization	855	9	—
Taxes other than income taxes	405	14	(18)
Total operating expenses	5,906	(72)	(714)
Operating income	2,477	129	52
Interest expense, net of amounts capitalized	388	25	15
Other income (expense), net	38	(23)	38
Income taxes	780	11	40
Net income	1,347	70	35
Dividends on preferred and preference stock	17	—	—
Net income after dividends on preferred and preference stock	$1,330	$ 70	$ 35

Operating Revenues

Operating revenues for 2016 were $8.4 billion, reflecting a $57 million increase from 2015. Details of operating revenues were as follows:

	Amount	
	2016	2015
	(in millions)	
Retail — prior year	$7,727	$8,240
Estimated change resulting from —		
Rates and pricing	154	88
Sales growth (decline)	(10)	63
Weather	113	(19)
Fuel cost recovery	(212)	(645)
Retail — current year	7,772	7,727
Wholesale revenues —		
Non-affiliates	175	215
Affiliates	42	20
Total wholesale revenues	217	235
Other operating revenues	394	364
Total operating revenues	$8,383	$8,326
Percent change	0.7%	(7.4)%

Retail base revenues of $5.6 billion in 2016 increased $256 million, or 4.8%, compared to 2015. The significant factors driving this change are shown in the preceding table. The increase in rates and pricing was primarily due to increases in base tariffs approved under the 2013 ARP and the NCCR tariff, all effective January 1, 2016. Also contributing to the increase was the 2015 correction of an error affecting billings since 2013 to a small number of large commercial and industrial customers under a rate

plan allowing for variable demand-driven pricing. The increase was partially offset by an adjustment for an expected refund to retail customers as a result of the Company's retail ROE exceeding the allowed retail ROE range under the 2013 ARP during 2016. In 2016, residential base revenues increased $152 million, or 6.3%, commercial base revenues increased $65 million, or 3.0%, and industrial base revenues increased $39 million, or 5.6%, compared to 2015.
Retail base revenues of $5.3 billion in 2015 increased $133 million, or 2.6%, compared to 2014. The significant factors driving this change are shown in the preceding table. The increase in rates and pricing was primarily due to increases in base tariffs approved under the 2013 ARP and the NCCR tariff, all effective January 1, 2015, partially offset by the 2015 correction of an error affecting billings since 2013 to a small number of large commercial and industrial customers under a rate plan allowing for variable demand-driven pricing. In 2015, residential base revenues increased $104 million, or 4.5%, commercial base revenues increased $70 million, or 3.4%, and industrial base revenues decreased $41 million, or 5.6%, compared to 2014.
See Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" and " – Nuclear Construction" for additional information. Also see "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (decline) and weather.
Electric rates include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these fuel cost recovery provisions, fuel revenues generally equal fuel expenses and do not affect net income. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" herein for additional information.
Wholesale revenues from power sales to non-affiliated utilities were as follows:

	2016	2015	2014
	(in millions)		
Capacity and other	$72	$108	$164
Energy	103	107	171
Total non-affiliated	$175	$215	$335

Wholesale capacity revenues from PPAs are recognized either on a levelized basis over the appropriate contract period or the amounts billable under the contract terms and provide for recovery of fixed costs and a return on investment.
Wholesale revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company's and the Southern Company system's generation, demand for energy within the Southern Company system's electric service territory, and the availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost of energy.
Wholesale revenues from non-affiliated sales decreased $40 million, or 18.6%, in 2016 as compared to 2015 and decreased $120 million, or 35.8%, in 2015 as compared to 2014. The decrease in 2016 was related to decreases of $36 million in capacity revenues and $4 million in energy revenues. The decrease in 2015 was related to decreases of $64 million in energy revenues and $56 million in capacity revenues. The decreases in capacity revenues reflect the expiration of wholesale contracts in the second quarter 2016 and in December 2014, respectively, as well as the retirement of 14 coal-fired generating units since March 31, 2015 as a result of the Company's environmental compliance strategy. The decreases in energy revenues were primarily due to lower fuel prices. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" herein for additional information regarding the Company's environmental compliance strategy.
Wholesale revenues from sales to affiliated companies will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the FERC. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost. In 2016, wholesale revenues from sales to affiliates increased $22 million as compared to 2015 due to a 153.5% increase in KWH sales as a result of the lower cost of Company-owned

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

Other operating revenues increased $30 million, or 8.2%, in 2016 from the prior year primarily due to a $14 million increase related to customer temporary facilities services revenues and a $12 million increase in outdoor lighting revenues due to increased sales in new and replacement markets, primarily attributable to conversions from traditional to LED lighting. Other operating revenues decreased $7 million, or 1.9%, in 2015 from the prior year primarily due to a $16 million decrease in transmission service revenues primarily as a result of a contract that expired in December 2014, partially offset by an $11 million increase in outdoor lighting revenues.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2016 and the percent change from the prior year were as follows:

	Total KWHs 2016 (in billions)	Total KWH Percent Change 2016	Total KWH Percent Change 2015	Weather-Adjusted Percent Change 2016	Weather-Adjusted Percent Change 2015
Residential	27.6	3.5 %	(1.8)%	1.0 %	1.0 %
Commercial	32.9	0.7	0.9	(1.0)	1.5
Industrial	23.8	(0.2)	1.1	(0.9)	1.0
Other	0.6	(3.5)	(0.2)	(3.5)	(0.1)
Total retail	84.9	1.3	0.1	(0.4)%	1.2 %
Wholesale					
Non-affiliates	3.4	(2.5)	(19.0)		
Affiliates	1.4	153.5	(50.6)		
Total wholesale	4.8	18.8	(25.5)		
Total energy sales	89.7	2.1 %	(1.5)%		

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

In 2016, KWH sales for the residential class increased 3.5% compared to 2015 primarily due to warmer weather in the third quarter 2016 as compared to the corresponding period in 2015 and increased customer growth, partially offset by decreased customer usage. Weather-adjusted residential KWH sales increased by 1.0% primarily due to an increase of approximately 28,000 residential customers since December 31, 2015, partially offset by a decline in customer usage primarily resulting from an increase in multi-family housing and efficiency improvements in residential appliances and lighting. Weather-adjusted commercial KWH sales decreased by 1.0% primarily due to a decline in average customer usage resulting from an increase in electronic commerce transactions and energy saving initiatives, partially offset by an increase of approximately 2,600 commercial customers since December 31, 2015. Weather-adjusted industrial sales decreased 0.9% primarily due to decreased demand in the pipeline, primary metals, stone, clay, and glass, and textile sectors, partially offset by increased demand in the non-manufacturing sector.

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

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

Fuel and Purchased Power Expenses

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

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

	2016	2015	2014
Total generation (in billions of KWHs)	68.4	65.9	69.9
Total purchased power (in billions of KWHs)	24.8	25.6	23.1
Sources of generation (percent) —			
Coal	36	34	41
Nuclear	24	25	22
Gas	38	39	35
Hydro	2	2	2
Cost of fuel, generated (in cents per net KWH) —			
Coal	3.28	4.55	4.52
Nuclear	0.85	0.78	0.90
Gas	2.36	2.47	3.67
Average cost of fuel, generated (in cents per net KWH)	2.33	2.77	3.40
Average cost of purchased power (in cents per net KWH)(*)	4.53	4.33	5.20

(*) Average cost of purchased power includes fuel purchased by the Company for tolling agreements where power is generated by the provider.

Fuel and purchased power expenses were $2.7 billion in 2016, a decrease of $211 million, or 7.3%, compared to 2015. The decrease was primarily due to a $334 million decrease in the average cost of fuel due to lower coal and natural gas prices and a $37 million decrease in the volume of KWHs purchased. Partially offsetting these decreases were a $111 million increase in the volume of KWHs generated to meet customer demand and a $49 million increase in the average cost of purchased power.

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

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

Fuel

Fuel expense was $1.8 billion in 2016, a decrease of $226 million, or 11.1%, compared to 2015. The decrease was primarily due to a decrease of 18.6% in the average cost of coal and natural gas per KWH generated, partially offset by an increase of 10.0% in the volume of KWHs generated by coal. Fuel expense was $2.0 billion in 2015, a decrease of $514 million, or 20.2%, compared to 2014. The decrease was primarily due to a decrease of 32.7% in the average cost of natural gas per KWH generated and a decrease of 22.2% in the volume of KWHs generated by coal, partially offset by a 6.2% increase in the volume of KWHs generated by natural gas.

Purchased Power - Non-Affiliates

Purchased power expense from non-affiliates was $361 million in 2016, an increase of $72 million, or 24.9%, compared to 2015. The increase was primarily due to a 36.8% increase in the volume of KWHs purchased to meet customer demand, partially offset by a 12.5% decrease in the average cost per KWH purchased due to lower natural gas prices. Purchased power expense from non-affiliates was $289 million in 2015, an increase of $2 million, or 0.7%, compared to 2014. The increase was primarily due to a 28.1% increase in the volume of KWHs purchased to meet customer demand, partially offset by a 19.8% decrease in the average cost per KWH purchased due to lower natural gas prices.

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 electric service territory, and the availability of the Southern Company system's generation.

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Purchased Power - Affiliates
Purchased power expense from affiliates was $518 million in 2016, a decrease of $57 million, or 9.9%, compared to 2015. The decrease was primarily due to an 11.9% decrease in the volume of KWHs purchased due to the lower market cost of available energy as compared to Southern Company system resources, partially offset by a 6.2% increase in the average cost per KWH purchased. Purchased power expense from affiliates was $575 million in 2015, a decrease of $126 million, or 18.0%, compared to 2014. The decrease was primarily due to a decrease of 17.4% in the average cost per KWH purchased reflecting lower natural gas prices, partially offset by an 8.1% increase in the volume of KWHs purchased to meet customer demand.
Energy purchases from affiliates will vary depending on the demand and the availability and cost of generating resources at each company within the Southern Company system. These purchases are made in accordance with the IIC or other contractual agreements, all as approved by the FERC.
Other Operations and Maintenance Expenses
In 2016, other operations and maintenance expenses increased $116 million, or 6.3%, compared to 2015. The increase was primarily due to a $37 million decrease in gains from sales of assets, a $36 million charge in connection with cost containment activities, a $30 million increase in overhead line maintenance, a $15 million increase in hydro and gas generation maintenance, a $10 million increase in customer accounts, service, and sales costs, and a $7 million increase in material costs related to higher generation volumes. The increase was partially offset by a decrease of $36 million in pension costs.
In 2015, other operations and maintenance expenses decreased $58 million, or 3.0%, compared to 2014. The decrease was primarily due to decreases of $51 million in transmission operating expenses, primarily due to gains from sales of assets and billing adjustments with integrated transmission system owners, $28 million in transmission and distribution overhead line maintenance, and $11 million in workers compensation and legal expense related to a lower volume of claims, partially offset by an increase of $33 million in employee benefits including pension costs.
See FUTURE EARNINGS POTENTIAL – "Other Matters" herein and Note 2 to the financial statements for additional information related to the cost containment activities and pension costs, respectively.
Depreciation and Amortization
Depreciation and amortization increased $9 million, or 1.1%, in 2016 compared to 2015. The increase was primarily due to a $34 million increase related to additional plant in service and a $9 million increase in other cost of removal, partially offset by an $18 million decrease related to amortization of nuclear construction financing costs that was completed in December 2015 and a decrease of $16 million related to unit retirements.
Depreciation and amortization remained flat in 2015 compared to 2014 primarily due to a $16 million decrease related to unit retirements and a $9 million decrease related to other cost of removal obligations, largely offset by a $23 million increase related to additional plant in service.
See Note 1 to the financial statements under "Depreciation and Amortization" for additional information.
Taxes Other Than Income Taxes
In 2016, taxes other than income taxes increased $14 million, or 3.6%, compared to 2015 primarily due to increases of $7 million in property taxes as a result of an increase in the assessed value of property and $4 million in payroll taxes.
In 2015, taxes other than income taxes decreased $18 million, or 4.4%, compared to 2014 primarily due to decreases of $15 million in municipal franchise fees related to lower retail revenues and $5 million in payroll taxes.
Interest Expense, Net of Amounts Capitalized
In 2016, interest expense, net of amounts capitalized increased $25 million, or 6.9%, compared to the prior year. The increase was primarily due to a $34 million increase in interest due to additional long-term borrowings from the FFB and higher interest rates on obligations for pollution control revenue bonds remarketed in 2015, partially offset by an increase of $4 million in AFUDC debt.
In 2015, interest expense, net of amounts capitalized increased $15 million, or 4.3%, compared to the prior year. The increase was primarily due to a $23 million increase in interest due to additional long-term debt borrowings from the

FFB, partially offset by an $11 million decrease in interest on senior notes due to redemptions and maturities.

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Other Income (Expense), Net

In 2016, other income (expense), net decreased $23 million compared to the prior year primarily due to decreases of $8 million in customer contributions in aid of construction, $6 million in wholesale operating fee revenue, and $4 million in gains on purchases of state tax credits.

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

Income Taxes

Income taxes increased $11 million, or 1.4%, in 2016 compared to the prior year primarily due to higher pre-tax earnings, partially offset by decreases in non-deductible book depreciation and increased state investment tax credits.

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

Effects of Inflation

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

FUTURE EARNINGS POTENTIAL

General

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

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs and limited projected demand growth over the next several years. The completion and subsequent operation of ongoing construction projects, primarily Plant Vogtle Units 3 and 4, also are major factors. Future earnings will be driven primarily by customer growth. Earnings will also depend upon maintaining and growing sales, considering, among other things, the adoption and/or penetration rates of increasingly energy-efficient technologies, increasing volumes of electronic commerce transactions, and higher multi-family home construction. Earnings are subject to a variety of other 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 primarily 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.

Current proposals related to potential tax reform legislation are primarily focused on reducing the corporate income tax rate, allowing 100% of capital expenditures to be deducted, and eliminating the interest deduction. The ultimate impact of any tax reform proposals, including any potential changes to the availability of nuclear PTCs, is dependent on the final form of any legislation enacted and the related transition rules and cannot be determined at this time, but could have a material impact on the Company's financial statements.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified, as compliance plans are revised or updated, and as legal challenges to rules are completed. The Company's Environmental Compliance Cost Recovery (ECCR) tariff allows for the recovery of capital and operations and maintenance costs related to environmental controls mandated by state and federal regulations. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Environmental Matters" for additional information.

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; the Migratory Bird Treaty Act; the Bald and Golden Eagle Protection Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2016, the Company had invested approximately $5.2 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $0.2 billion, $0.3 billion, and $0.4 billion for 2016, 2015, and 2014, respectively. The Company expects that capital expenditures to comply with environmental statutes and regulations will total approximately $1.2 billion from 2017 through 2021, with annual totals of approximately $0.4 billion, $0.3 billion, $0.1 billion, $0.2 billion, and $0.2 billion for 2017, 2018, 2019, 2020, and 2021, respectively. These estimated expenditures do not include any potential capital expenditures that may arise from the EPA's final rules and guidelines or future state plans that would limit CO_2 emissions from existing, new, modified, or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" herein for additional information. The Company also anticipates costs associated with ash pond closure and ground water monitoring under the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), which are reflected in the Company's ARO liabilities. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 1 to the financial statements under "Asset Retirement Obligations and Other Cost of Removal" 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 time periods over which compliance with regulations is required; individual state implementation of regulations, as applicable; the outcome of any legal challenges to the environmental rules; any additional rulemaking activities in response to legal challenges and court decisions; the cost, availability, and existing inventory of emissions allowances; the impact of future changes in generation and emissions-related technology; the Company's fuel mix; and environmental remediation requirements. 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.

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.

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 implementation strategy for the MATS rule included emission controls, retirements, and fuel conversions at affected units. All of the Company's units that are subject to the MATS rule completed the measures necessary to achieve compliance with this rule or were retired prior to or during 2016.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone National Ambient Air Quality Standard (NAAQS). In 2008, the EPA adopted a revised eight-hour ozone NAAQS and published its final area designations in 2012. The only area within the Company's service territory designated as an ozone nonattainment area for the 2008 standard is a 15-county area within metropolitan Atlanta, which on December 23, 2016, the EPA proposed to redesignate to attainment. In October 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 were required to recommend area designations by October 2016, and the only area within the

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Company's service territory that was proposed for designation is an eight-county area within the Atlanta metropolitan area in Georgia. The EPA is expected to finalize area designations by October 2017.
The EPA regulates fine particulate matter concentrations through an annual and 24-hour average NAAQS, based on standards promulgated in 1997, 2006, and 2012. All areas in which the Company's generating units are located have been determined by the EPA to be in attainment with those standards.
In 2010, the EPA revised the NAAQS for sulfur dioxide (SO_2), establishing a new one-hour standard. No areas within the Company's service territory have been designated as nonattainment under this standard. However, in 2015, the EPA finalized a data requirements rule to support final EPA designation decisions for all remaining areas under the SO_2 standard, which could result in nonattainment designations for areas within the Company's service territory. Nonattainment designations could require additional reductions in SO_2 emissions and increased compliance and operational costs.
In 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, including units owned by SEGCO, which is jointly owned by Alabama Power and the Company. In 2013, the U.S. Court of Appeals for the Eleventh Circuit ruled in favor of Alabama Power and 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. Alabama Power and the Company believe 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 SEGCO. See Note 4 to the financial statements for additional information regarding SEGCO.
On July 6, 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide (NO_x) emissions from power plants in two phases – Phase 1 in 2015 and Phase 2 in 2017. On October 26, 2016, the EPA published a final rule that updates the CSAPR ozone season NO_x program, beginning in 2017, and establishes more stringent ozone-season emissions budgets in Alabama. The State of Georgia's emission budget was not affected by the revisions, but interstate emissions trading is restricted unless the state decides to voluntarily adopt a reduced budget. Georgia and Alabama are also in the CSAPR annual SO_2 and NO_x programs.
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. On December 14, 2016, the EPA finalized revisions to the regional haze regulations. These regulations establish a deadline of July 31, 2021 for states to submit revised SIPs to the EPA demonstrating reasonable progress toward the statutory goal of achieving natural background conditions by 2064. State implementation of the reasonable progress requirements defined in this final rule could require further reductions in SO_2 or NO_x emissions.
In June 2015, the EPA published a final rule requiring certain states (including Georgia and 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), and the State of Georgia has submitted proposed SIP revisions in response to the rule.
The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the current and proposed environmental requirements discussed above. 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. The ultimate impact of the eight-hour ozone and SO_2 NAAQS, Alabama opacity rule, CSAPR, regional haze regulations, and SSM rule will depend on various factors, such as implementation, adoption, or other action at the state level, and the outcome of pending and/or future legal

challenges, and cannot be determined at this time.
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 2014. The effect of this final rule will depend on the results of additional studies that are currently underway and implementation of the rule by regulators based on site-specific factors. National Pollutant Discharge Elimination System (NPDES) permits issued after July 14, 2018 must include conditions to implement and ensure compliance with the standards and protective measures required by the rule.
In November 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 NPDES 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.

In 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 in August 2015 but, in October 2015, the U.S. Court of Appeals for the Sixth Circuit issued an order staying implementation of the final rule. The case is held in abeyance pending review by the U.S. Supreme Court of challenges to the U.S. Court of Appeals for the Sixth Circuit's jurisdiction in the case.

These water quality regulations could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions and decisions on infrastructure expansion and improvements. 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. The ultimate impact of these final rules will depend on various factors, such as pending and/or future legal challenges, compliance dates, and implementation of the rules, and cannot be determined at this time.

Coal Combustion Residuals

The Company currently manages CCR at onsite storage units consisting of landfills and surface impoundments (CCR Units) at 12 current or former electric generating plants. In addition to on-site storage, the Company also sells a portion of its CCR to third parties for beneficial reuse. Individual states regulate CCR and the State of Georgia has its own regulatory requirements. The Company has an inspection program in place to assist in maintaining the integrity of its coal ash surface impoundments.

The CCR Rule became effective in October 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. On December 16, 2016, President Obama signed the Water Infrastructure Improvements for the Nation Act (WIIN Act). The WIIN Act allows states to establish permit programs for implementing the CCR Rule, if the EPA approves the program, and allows for federal permits and EPA enforcement where a state permitting program does not exist. On October 26, 2016, the Georgia Department of Natural Resources approved amendments to its state solid waste regulations to incorporate the requirements of the CCR Rule and establish additional requirements for all of the Company's onsite storage units consisting of landfills and surface impoundments.

Based on current cost estimates for closure and monitoring of ash ponds pursuant to the CCR Rule, the Company has recorded incremental AROs related to the CCR Rule. As further analysis is performed, including evaluation of the expected method of compliance, refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, and the determination of timing with respect to compliance activities, the Company expects to continue to periodically update these estimates. The Company has posted closure and post-closure care plans to its public website as required by the CCR Rule; however, the ultimate impact of the CCR Rule will depend on the results of initial and ongoing minimum criteria assessments and implementation of state or federal permit programs. 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, 2016.

Environmental Remediation

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

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Global Climate Issues

In October 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 review with the courts. The stay will remain in effect through the resolution of the litigation, including any review by 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 and decisions on infrastructure expansion and improvements. 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 outcome of pending legal challenges, including legal challenges filed by the traditional electric operating companies, and any individual state implementation of the EPA's final guidelines in the event the rule is upheld and implemented.

In December 2015, parties to the United Nations Framework Convention on Climate Change – including the United States – adopted 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 tracking progress toward the goals every five years. The ultimate impact of this agreement depends on its implementation by participating countries and cannot be determined at this time.

The EPA's greenhouse gas reporting rule requires annual reporting of greenhouse gas emissions expressed in terms of metric tons of CO_2 equivalent emissions for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2015 greenhouse gas emissions were approximately 32 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2016 greenhouse gas emissions on the same basis is approximately 33 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 electric operating companies (including the Company) and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In April 2015, the FERC issued an order finding that the traditional electric 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 electric operating companies and in some adjacent areas. The FERC directed the traditional electric 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 electric operating companies (including the Company) and Southern Power filed a request for rehearing in May 2015 and in June 2015 filed their response with the FERC.

On December 9, 2016, the traditional electric operating companies (including the Company) and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' (including the Company's) and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies (including the Company) and in some adjacent areas. The traditional electric operating companies (including the Company) and Southern Power expect to make a compliance filing within 30 days accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.

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

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Retail Regulatory Matters

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

Rate Plans

Pursuant to the terms and conditions of a settlement agreement related to Southern Company's acquisition of Southern Company Gas approved by the Georgia PSC on April 14, 2016, the 2013 ARP will continue in effect until December 31, 2019, and the Company will be required to file its next base rate case by July 1, 2019. Furthermore, through December 31, 2019, the Company and Atlanta Gas Light Company each will retain their respective merger savings, net of transition costs, as defined in the settlement agreement; through December 31, 2022, such net merger savings applicable to each will be shared on a 60/40 basis with their respective customers; thereafter, all merger savings will be retained by customers. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information regarding the 2013 ARP.

In accordance with the 2013 ARP, the Georgia PSC approved increases to tariffs effective January 1, 2015 and 2016 as follows: (1) traditional base tariff rates by approximately $107 million and $49 million, respectively; (2) ECCR tariff by approximately $23 million and $75 million, respectively; (3) DSM tariffs by approximately $3 million in each year; and (4) MFF tariff by approximately $3 million and $13 million, respectively, for a total increase in base revenues of approximately $136 million and $140 million, respectively.

Under the 2013 ARP, the Company's retail ROE is set at 10.95% and earnings are evaluated against a retail ROE range of 10.00% to 12.00%. Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by the Company. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. In 2014, the Company's retail ROE exceeded 12.00%, and the Company refunded to retail customers approximately $11 million in 2016, as approved by the Georgia PSC on February 18, 2016. In 2015, the Company's retail ROE was within the allowed retail ROE range. In 2016, the Company's retail ROE exceeded 12.00%, and the Company expects to refund to retail customers approximately $40 million, subject to review and approval by the Georgia PSC. The ultimate outcome of this matter cannot be determined at this time.

Renewables

In 2014, the Georgia PSC approved the Company's application for the certification of two PPAs executed in 2013 for the purchase of energy from two wind farms in Oklahoma with capacity totaling 250 MWs that began in 2016 and have 20-year terms.

As part of the Georgia Power Advanced Solar Initiative (ASI), in 2014, the Georgia PSC approved PPAs executed since April 2015 for the purchase of energy from 555 MWs of solar capacity that began in 2015 and 2016 and have terms ranging from 20 to 30 years. As a result of certain acquisitions by Southern Power, 249 MWs of this contracted capacity is being provided from solar facilities owned by Southern Power through five PPAs that began in 2016. Ownership of any associated renewable energy credits (REC) is specified in each respective PPA. The party that owns the RECs retains the right to use them.

In 2014, the Georgia PSC approved the Company's request to build, own, and operate 30-MW solar generation facilities at three U.S. Army bases and one U.S. Navy base by the end of 2016. One of the four solar generation facilities began commercial operation in December 2015 and the remaining three began in the fourth quarter 2016. In December 2015, the Georgia PSC approved the Company's request to build, own, and operate a 31-MW solar generation facility at a U.S. Marine Corps base that is expected to begin commercial operation by summer 2017 and a 15-MW solar generation facility at a yet-to-be-determined U.S. military base. The ultimate outcome of this matter cannot be determined at this time.

Two PPAs for biomass generation capacity of 58 MWs each were executed in June 2015 and November 2015 and are expected to begin in 2019.
See "Integrated Resource Plan" herein for additional information on renewables.
Integrated Resource Plan
See "Environmental Matters" herein for additional information regarding proposed and final EPA rules and regulations, including the MATS rule for coal- and oil-fired electric utility steam generating units, revisions to effluent limitations guidelines for steam

electric power plants, and additional regulations of CCR and CO_2; and the Company's analysis of the potential costs and benefits of installing the required controls on its fossil generating units in light of these regulations.

On July 28, 2016, the Georgia PSC approved the 2016 IRP including the decertification and retirement of Plant Mitchell Units 3, 4A, and 4B (217 MWs) and Plant Kraft Unit 1 (17 MWs), as well as the decertification of the Intercession City unit (143 MWs total capacity). On August 2, 2016, the Plant Mitchell and Plant Kraft units were retired. On August 31, 2016, the Company sold its 33% ownership interest in the Intercession City unit to Duke Energy Florida, LLC.

Additionally, the Georgia PSC approved the Company's environmental compliance strategy and related expenditures proposed in the 2016 IRP, including measures taken to comply with existing government-imposed environmental mandates, subject to limits on expenditures for Plant McIntosh Unit 1 and Plant Hammond Units 1 through 4.

The Georgia PSC approved the reclassification of the remaining net book value of Plant Mitchell Unit 3 and costs associated with materials and supplies remaining at the unit retirement date to a regulatory asset. Recovery of the unit's net book value will continue through December 31, 2019, as provided in the 2013 ARP. The timing of the recovery of the remaining balance of the unit's net book value as of December 31, 2019 and costs associated with materials and supplies remaining at the unit retirement date was deferred for consideration in the Company's 2019 base rate case.

The Georgia PSC also approved the Renewable Energy Development Initiative to procure an additional 1,200 MWs of renewable resources primarily utilizing market-based prices established through a competitive bidding process with expected in-service dates between 2018 and 2021. Additionally, 200 MWs of self-build capacity for use by the Company was approved, as well as consideration for no more than 200 MWs of capacity as part of a renewable commercial and industrial program.

The Georgia PSC also approved recovery of costs up to $99 million through June 30, 2019 to preserve nuclear as an option at a future generation site in Stewart County, Georgia. The timing of cost recovery will be determined by the Georgia PSC in a future base rate case. The ultimate outcome of this matter cannot be determined at this time.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. In December 2015, the Georgia PSC approved the Company's request to lower annual billings by approximately $350 million effective January 1, 2016. On May 17, 2016, the Georgia PSC approved the Company's request to further lower annual billings by approximately $313 million effective June 1, 2016. On December 6, 2016, the Georgia PSC approved the delay of the Company's next fuel case, which was previously scheduled to be filed by February 28, 2017. The Georgia PSC will review the Company's cumulative over or under recovered fuel balance no later than September 1, 2018 and evaluate the need to file a fuel case unless the Company deems it necessary to file a fuel case at an earlier time. Under an Interim Fuel Rider, the Company continues to be allowed to adjust its fuel cost recovery rates prior to the next fuel case if the under recovered fuel balance exceeds $200 million.

The Company's fuel cost recovery mechanism includes costs associated with a natural gas hedging program, as revised and approved by the Georgia PSC, allowing the use of an array of derivative instruments within a 48-month time horizon effective January 1, 2016.

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

Storm Damage Recovery

As of December 31, 2016, the balance in the Company's regulatory asset related to storm damage was $206 million. During October 2016, Hurricane Matthew caused significant damage to the Company's transmission and distribution facilities. As of December 31, 2016, the Company had recorded incremental restoration cost related to this hurricane of $121 million, of which approximately $116 million was charged to the storm damage reserve and the remainder was capitalized. The Company is accruing $30 million annually through December 31, 2019, as provided in the 2013

ARP, to the storm damage reserve to cover the operations and maintenance costs of damages from major storms to its transmission and distribution facilities, which is recoverable through base rates. The rate of recovery of storm damage costs after December 31, 2019 is expected to be adjusted in the Company's 2019 base rate case. As a result of this regulatory treatment, costs related to storms are not expected to have a material impact on the Company's financial statements. See Note 1 to the financial statements under "Storm Damage Recovery" for additional information regarding the Company's storm damage reserve.

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Nuclear Construction

In 2008, the Company, acting for itself and as agent for Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia (Dalton), acting by and through its Board of Water, Light, and Sinking Fund Commissioners, doing business as Dalton Utilities (collectively, Vogtle Owners), entered into an agreement with a consortium consisting of Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc., which was subsequently acquired by Westinghouse and changed its name to WECTEC Global Project Services Inc. (WECTEC) (Westinghouse and WECTEC, collectively, Contractor), pursuant to which the Contractor agreed to design, engineer, procure, construct, and test two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities at Plant Vogtle (Vogtle 3 and 4 Agreement).

Under the terms of the Vogtle 3 and 4 Agreement, the Vogtle Owners agreed to pay a purchase price subject to certain price escalations and adjustments, including fixed escalation amounts and index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. The Vogtle 3 and 4 Agreement also provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees, subject to an aggregate cap of 10% of the contract price, or approximately $920 million to $930 million. In addition, the Vogtle 3 and 4 Agreement provides for limited cost sharing by the Vogtle Owners for Contractor costs under certain conditions (which the Company has not been notified have occurred) with maximum additional capital costs under this provision attributable to the Company (based on the Company's ownership interest) of approximately $114 million. Each Vogtle Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Contractor under the Vogtle 3 and 4 Agreement. The Company's proportionate share is 45.7%. In the event of certain credit rating downgrades of any Vogtle Owner, such Vogtle Owner will be required to provide a letter of credit or other credit enhancement.

Certain obligations of Westinghouse have been guaranteed by Toshiba Corporation (Toshiba), Westinghouse's parent company. In the event of certain credit rating downgrades of Toshiba, Westinghouse is required to provide letters of credit or other credit enhancement. In December 2015, Toshiba experienced credit rating downgrades and Westinghouse provided the Vogtle Owners with $920 million of letters of credit. These letters of credit remain in place in accordance with the terms of the Vogtle 3 and 4 Agreement.

On February 14, 2017, Toshiba announced preliminary earnings results for the period ended December 31, 2016, which included a substantial goodwill impairment charge at Westinghouse attributed to increased cost estimates to complete its U.S. nuclear projects, including Plant Vogtle Units 3 and 4. Toshiba also warned that it will likely be in a negative equity position as a result of the charges. At the same time, Toshiba reaffirmed its commitment to its U.S. nuclear projects with implementation of management changes and increased oversight. An inability or failure by the Contractor to perform its obligations under the Vogtle 3 and 4 Agreement could have a material impact on the construction of Plant Vogtle Units 3 and 4.

Under the terms of the Vogtle 3 and 4 Agreement, the Contractor does not have a right to terminate the Vogtle 3 and 4 Agreement for convenience. The Contractor may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including certain Vogtle Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Vogtle Owners, Vogtle Owner insolvency, and certain other events. In the event of an abandonment of work by the Contractor, the maximum liability of the Contractor under the Vogtle 3 and 4 Agreement is increased significantly, but remains subject to limitations. The Vogtle Owners may terminate the Vogtle 3 and 4 Agreement at any time for convenience, provided that the Vogtle Owners will be required to pay certain termination costs.

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4 with a certified capital cost of $4.418 billion. In addition, in 2009 the Georgia PSC approved inclusion of the Plant Vogtle Units 3 and 4 related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows the Company to recover financing costs for nuclear construction projects certified by the Georgia PSC. Financing costs are recovered on all applicable certified costs through annual adjustments to the NCCR tariff by including the related CWIP accounts in rate base during the construction period. The Georgia PSC approved an NCCR tariff of $368 million for 2014, as well as increases to the NCCR tariff of approximately $27 million and $19 million effective January 1, 2015 and 2016, respectively.

The Company is required to file semi-annual Vogtle Construction Monitoring (VCM) reports with the Georgia PSC by February 28 and August 31 each year. In accordance with the 2009 certification order, the Company requested amendments to the Plant Vogtle Units 3 and 4 certificate in both the February 2013 (eighth VCM) and February 2015 (twelfth VCM) filings, when projected construction capital costs to be borne by the Company increased by 5% above the certified costs and estimated in-service dates were extended. In October 2013, the Georgia PSC approved a stipulation (2013 Stipulation) between the Company and the Georgia PSC Staff to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate until the completion of Plant Vogtle Unit 3 or earlier if deemed appropriate by the Georgia PSC and the Company. In April 2015, the Georgia PSC recognized that the certified cost and the 2013 Stipulation did not constitute a cost recovery cap and deemed the amendment

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requested in the February 2015 filing unnecessary and withdrawn until the completion of construction of Plant Vogtle Unit 3 consistent with the 2013 Stipulation.

On December 31, 2015, Westinghouse and the Vogtle Owners entered into a definitive settlement agreement (Contractor Settlement Agreement) to resolve disputes between the Vogtle Owners and the Contractor under the Vogtle 3 and 4 Agreement, including litigation that was pending in the U.S. District Court for the Southern District of Georgia (Vogtle Construction Litigation). Effective December 31, 2015, the Company, acting for itself and as agent for the other Vogtle Owners, and the Contractor entered into an amendment to the Vogtle 3 and 4 Agreement to implement the Contractor Settlement Agreement. The Contractor Settlement Agreement and the related amendment to the Vogtle 3 and 4 Agreement (i) restrict the Contractor's ability to seek further increases in the contract price by clarifying and limiting the circumstances that constitute nuclear regulatory changes in law; (ii) provide for enhanced dispute resolution procedures; (iii) revise the guaranteed substantial completion dates to June 30, 2019 for Unit 3 and June 30, 2020 for Unit 4; (iv) provide that delay liquidated damages will commence if the nuclear fuel loading date for each unit does not occur by December 31, 2018 for Unit 3 and December 31, 2019 for Unit 4; and (v) provide that the Company, based on its ownership interest, will pay to the Contractor and capitalize to the project cost approximately $350 million, of which approximately $263 million had been paid as of December 31, 2016. In addition, the Contractor Settlement Agreement provides for the resolution of other open existing items relating to the scope of the project under the Vogtle 3 and 4 Agreement, including cyber security, for which costs are reflected in the Company's current in-service forecast of $5.440 billion. Further, as part of the settlement and Westinghouse's acquisition of WECTEC: (i) Westinghouse engaged Fluor Enterprises, Inc., a subsidiary of Fluor Corporation, as a new construction subcontractor and (ii) the Vogtle Owners, Chicago Bridge & Iron Co, N.V., and The Shaw Group Inc. entered into mutual releases of any and all claims arising out of events or circumstances in connection with the construction of Plant Vogtle Units 3 and 4 that occurred on or before the date of the Contractor Settlement Agreement. On January 5, 2016, the Vogtle Construction Litigation was dismissed with prejudice.

On December 20, 2016, the Georgia PSC voted to approve a settlement agreement (Vogtle Cost Settlement Agreement) resolving the following prudence matters: (i) none of the $3.3 billion of costs incurred through December 31, 2015 and reflected in the fourteenth VCM report will be disallowed from rate base on the basis of imprudence; (ii) the Contractor Settlement Agreement is reasonable and prudent and none of the amounts paid or to be paid pursuant to the Contractor Settlement Agreement should be disallowed from rate base on the basis of imprudence; (iii) financing costs on verified and approved capital costs will be deemed prudent provided they are incurred prior to December 31, 2019 and December 31, 2020 for Plant Vogtle Units 3 and 4, respectively; and (iv) (a) the in-service capital cost forecast will be adjusted to $5.680 billion (Revised Forecast), which includes a contingency of $240 million above the Company's current forecast of $5.440 billion, (b) capital costs incurred up to the Revised Forecast will be presumed to be reasonable and prudent with the burden of proof on any party challenging such costs, and (c) the Company would have the burden to show that any capital costs above the Revised Forecast are reasonable and prudent. Under the terms of the Vogtle Cost Settlement Agreement, the certified in-service capital cost for purposes of calculating the NCCR tariff will remain at $4.418 billion. Construction capital costs above $4.418 billion will accrue AFUDC through the date each unit is placed in service. The ROE used to calculate the NCCR tariff was reduced from 10.95% (the ROE rate setting point authorized by the Georgia PSC in the 2013 ARP) to 10.00% effective January 1, 2016. For purposes of the AFUDC calculation, the ROE on costs between $4.418 billion and $5.440 billion will also be 10.00% and the ROE on any amounts above $5.440 billion would be the Company's average cost of long-term debt. If the Georgia PSC adjusts the Company's ROE rate setting point in a rate case prior to Plant Vogtle Units 3 and 4 being placed into retail rate base, then the ROE for purposes of calculating both the NCCR tariff and AFUDC will likewise be 95 basis points lower than the revised ROE rate setting point. If Plant Vogtle Units 3 and 4 are not placed in service by December 31, 2020, then (i) the ROE for purposes of calculating the NCCR tariff will be reduced an additional 300 basis points, or $8 million per month, and may, at the Georgia PSC's discretion, be accrued to be used for the benefit of customers, until such time as the units are placed in service and (ii) the ROE used to calculate AFUDC will be the

Company's average cost of long-term debt.

Under the terms of the Vogtle Cost Settlement Agreement, Plant Vogtle Units 3 and 4 will be placed into retail rate base on December 31, 2020 or when placed in service, whichever is later. The Georgia PSC will determine for retail ratemaking purposes the process of transitioning Plant Vogtle Units 3 and 4 from a construction project to an operating plant no later than the Company's base rate case required to be filed by July 1, 2019.

The Georgia PSC has approved fifteen VCM reports covering the periods through June 30, 2016, including construction capital costs incurred, which through that date totaled $3.7 billion. The Company expects to file the sixteenth VCM report, covering the period from July 1 through December 31, 2016, requesting approval of $222 million of construction capital costs incurred during that period, with the Georgia PSC by February 28, 2017. The Company's CWIP balance for Plant Vogtle Units 3 and 4 was approximately $3.9 billion as of December 31, 2016, and the Company had incurred $1.3 billion in financing costs through December 31, 2016.

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As of December 31, 2016, the Company had borrowed $2.6 billion related to Plant Vogtle Units 3 and 4 costs through a loan guarantee agreement between the Company and the DOE and a multi-advance credit facility among the Company, the DOE, and the FFB. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information, including applicable covenants, events of default, and mandatory prepayment events.
There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4 at the federal and state level and additional challenges may arise as construction proceeds. Processes are in place that are designed to assure compliance with the requirements specified in the Westinghouse Design Control Document and the combined construction and operating licenses, including inspections by Southern Nuclear and the NRC that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the NRC. Various design and other licensing-based compliance matters, including the timely resolution of Inspections, Tests, Analyses, and Acceptance Criteria and the related approvals by the NRC, may arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs either to the Vogtle Owners or the Contractor or to both.
In addition to Toshiba's reaffirmation of its commitment, the Contractor provided the Company with revised forecasted in-service dates of December 2019 and September 2020 for Plant Vogtle Units 3 and 4, respectively. The Company is currently reviewing a preliminary summary schedule supporting these dates that ultimately must be reconciled to a detailed integrated project schedule. As construction continues, the risk remains that challenges with Contractor performance including labor productivity, fabrication, delivery, assembly, and installation of plant systems, structures, and components, or other issues could arise and may further impact project schedule and cost. The Company expects the Contractor to employ mitigation efforts and believes the Contractor is responsible for any related costs under the Vogtle 3 and 4 Agreement. The Company estimates its financing costs for Plant Vogtle Units 3 and 4 to be approximately $30 million per month, with total construction period financing costs of approximately $2.5 billion. Additionally, the Company estimates its owner's costs to be approximately $6 million per month, net of delay liquidated damages.
The revised forecasted in-service dates are within the timeframe contemplated in the Vogtle Cost Settlement Agreement and would enable both units to qualify for production tax credits the IRS has allocated to each of Plant Vogtle Units 3 and 4, which require the applicable unit to be placed in service before 2021. The net present value of the production tax credits is estimated at approximately $400 million per unit.
Future claims by the Contractor or the Company (on behalf of the Vogtle Owners) could arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the Vogtle 3 and 4 Agreement and, under the enhanced dispute resolution procedures, may be resolved through litigation after the completion of nuclear fuel load for both units.
The ultimate outcome of these matters cannot be determined at this time.
Income Tax Matters
Bonus Depreciation
In December 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. Bonus depreciation was extended for qualified property placed in service through 2020. The PATH Act allows for 50% bonus depreciation for 2015 through 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 bonus depreciation included in the PATH Act is expected to result in approximately $300 million of positive cash flows for the 2016 tax year and approximately $210 million for the 2017 tax year. See Note 5 to the financial statements for additional information.
Other Matters
The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of

business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters.

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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.

The Company regularly evaluates its operations and costs. Primarily in response to changing customer expectations and payment patterns, including electronic payments and alternative payment locations, and on-going efforts to increase overall operating efficiencies, the Company initiated cost containment activities throughout the enterprise in July 2016, including the closure of 104 local offices and an employee attrition plan affecting approximately 300 positions. Charges associated with the cost containment activities did not have a material impact on the Company's results of operations, financial position, or cash flows. The cost containment activities are expected to reduce operating costs in 2017.

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.

Utility Regulation

The Company is subject to retail regulation by the Georgia PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation, AROs, and pension and other postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and any requirement to refund these regulatory liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Asset Retirement Obligations

AROs are computed as the fair value of the estimated ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities.

The liability for AROs primarily relates to the decommissioning of the Company's nuclear facilities, which include the Company's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2, and facilities that are subject to the CCR Rule, principally ash ponds. In addition, the Company has retirement obligations related to various landfill sites, underground storage tanks, and asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities, including the disposal of polychlorinated biphenyls in certain transformers; leasehold improvements; equipment on customer property; and property associated with the Company's rail lines and natural gas pipelines. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO.

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The Company previously recorded AROs as a result of state requirements in Georgia which closely align with the requirements of the CCR Rule discussed above. The cost estimates are based on information using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule requirements for closure. 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 with respect to compliance activities, 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. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Coal Combustion Residuals" herein for additional information. Given the significant judgment involved in estimating AROs, the Company considers the liabilities for AROs to be critical accounting estimates.

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

Pension and Other Postretirement Benefits

The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets, and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining the Company's pension and other postretirement benefit expense are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on pension and other postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. For purposes of determining its liability related to the pension and other postretirement benefit plans, the Company discounts the future related cash flows using a single-point discount rate for each plan developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments. For 2015 and prior years, the Company computed the interest cost component of its net periodic pension and other postretirement benefit plan expense using the same single-point discount rate. For 2016, the Company 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 decreased by approximately $35 million in 2016.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $10 million or less change in total annual benefit expense and a $147 million or less change in projected obligations.

See Note 2 to the financial statements for additional information regarding pension and other postretirement benefits.

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

In 2014, the FASB issued ASC 606, Revenue from Contracts with Customers, replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the guidance is to recognize revenue to depict the transfer of goods or services to

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customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers. While the Company expects most of its revenue to be included in the scope of ASC 606, it has not fully completed its evaluation of such arrangements. The majority of the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term. For such arrangements, the Company generally expects that the revenue from contracts with these customers will continue to be equivalent to the electricity supplied and billed in that period (including unbilled revenues) and the adoption of ASC 606 will not result in a significant shift in the timing of revenue recognition for such sales.

The Company's ongoing evaluation of other revenue streams and related contracts includes longer term contractual commitments and unregulated sales to customers. Some revenue arrangements, such as certain PPAs and alternative revenue programs, are expected to be excluded from the scope of ASC 606 and therefore, be accounted for and presented separately from revenues under ASC 606 on the Company's financial statements. In addition, the power and utilities industry is currently addressing other specific industry issues, including the applicability of ASC 606 to contributions in aid of construction (CIAC). If final implementation guidance indicates CIAC will be accounted for under ASC 606 and offsetting regulatory treatment is not permitted, it is expected to have a material impact on the Company's financial statements.

The new standard is effective for interim and annual reporting periods beginning after December 15, 2017. The Company must select a transition method to be applied either retrospectively to each prior reporting period presented or retrospectively with a cumulative effect adjustment to retained earnings at the date of initial adoption. As the ultimate impact of the new standard has not yet been determined, the Company has not elected its transition method.

On February 25, 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842) (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company is currently evaluating the new standard and has not yet determined its ultimate impact; however, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

On March 30, 2016, the FASB issued ASU No. 2016-09, Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting (ASU 2016-09). ASU 2016-09 changes the accounting for income taxes and the cash flow presentation for share-based payment award transactions effective for fiscal years beginning after December 15, 2016. The new guidance requires all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation to be recognized as income tax expense or benefit in the income statement. Previously, the Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities rather than net cash provided from financing activities on the statement of cash flows. The Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. The Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of the Company. See Notes 5, 8, and 12 to the financial statements for disclosures impacted by ASU 2016-09.

On October 24, 2016, the FASB issued ASU No. 2016-16, Income Taxes (Topic 740), Intra-Entity Transfers of Assets Other Than Inventory (ASU 2016-16). Current GAAP prohibits the recognition of current and deferred income taxes for an affiliate asset transfer until the asset has been sold to an outside party. ASU 2016-16 requires an entity to recognize the income tax consequences of an affiliate transfer of an asset other than inventory when the transfer occurs. ASU 2016-16 is effective for annual reporting periods beginning after December 15, 2017 and interim periods within those annual periods. The amendments will be applied on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. The Company is currently assessing the impact of the standard on its financial statements and has not yet determined its ultimate impact.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2016. 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 build new generation facilities, including Plant Vogtle Units 3 and 4, to maintain

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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existing generation facilities, to comply with environmental regulations including adding environmental modifications to existing generating units, to expand and improve transmission and distribution facilities, 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 2017 through 2019, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. The Company plans to finance future cash needs in excess of its operating cash flows primarily through securities issuances, capital contributions from Southern Company, borrowings from financial institutions, and borrowings through the FFB. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan and nuclear decommissioning trust funds increased in value as of December 31, 2016 as compared to December 31, 2015. On December 19, 2016, the Company voluntarily contributed $287 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated during 2017. The Company also funded approximately $5 million to its nuclear decommissioning trust funds in 2016. See "Contractual Obligations" herein and Notes 1 and 2 to the financial statements under "Nuclear Decommissioning" and "Pension Plans," respectively, for additional information.

Net cash provided from operating activities totaled $2.4 billion in 2016, a decrease of $92 million from 2015, primarily due to the voluntary contribution to the qualified pension plan, partially offset by the timing of vendor payments. Net cash provided from operating activities totaled $2.5 billion in 2015, an increase of $154 million from 2014, primarily due to increased fuel cost recovery, partially offset by the timing of vendor payments.

Net cash used for investing activities totaled $2.3 billion, $1.9 billion, and $2.2 billion in 2016, 2015, and 2014, respectively, due to gross property additions primarily related to installation of equipment to comply with environmental standards; construction of generation, transmission, and distribution facilities; and purchase of nuclear fuel. The majority of funds needed for gross property additions for the last several years has been provided from operating activities, capital contributions from Southern Company, and the issuance of debt. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Nuclear Construction" herein for additional information.

Net cash used for financing activities totaled $142 million, $530 million, and $163 million for 2016, 2015, and 2014, respectively. The decrease in cash used in 2016 compared to 2015 was primarily due to higher capital contributions from Southern Company, a decrease in redemptions and maturities of senior notes, and an increase in short-term debt, partially offset by higher common stock dividends and a decrease in borrowings from the FFB for construction of Plant Vogtle Units 3 and 4. The increase in cash used in 2015 compared to 2014 was primarily due to the redemption and maturity of senior notes in 2015. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes in 2016 included an increase in property, plant, and equipment of $1.6 billion to comply with environmental standards and construction of generation, transmission, and distribution facilities, increases in other regulatory assets, deferred of $622 million and current and deferred ARO liabilities of $616 million primarily related to changes in ash pond closure strategy, an increase of $373 million in accumulated deferred income taxes primarily as a result of bonus depreciation, and an increase of $357 million in long-term debt due to issuances exceeding maturities. See Note 1 to the financial statements for additional information.

The Company's ratio of common equity to total capitalization plus short-term debt, was 50.0% at December 31, 2016 and 49.9% at December 31, 2015. See Note 6 to the financial statements for additional information.

Sources of Capital

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

The Company may make borrowings through a loan guarantee agreement (Loan Guarantee Agreement) between the Company and the DOE, the proceeds of which may be used to reimburse the Company for a portion of certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the Loan Guarantee Agreement (Eligible Project Costs). Under the Loan Guarantee Agreement, the DOE agreed to guarantee borrowings of up to $3.46 billion (not to exceed 70% of Eligible Project Costs) to be made by the Company under a multi-advance credit facility (FFB Credit Facility) among the Company, the DOE, and the FFB. Eligible Project Costs incurred through December 31, 2016 would allow for borrowings of up to $2.7 billion under the FFB Credit Facility, of which the Company has borrowed $2.6 billion. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information regarding the Loan Guarantee Agreement and Note 3 to the financial statements under "Retail Regulatory Matters – Nuclear Construction" for additional information regarding Plant Vogtle Units 3 and 4.

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

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

At December 31, 2016, the Company's current liabilities exceeded current assets by $1.5 billion. The Company's current liabilities frequently exceed current assets because of scheduled maturities of long-term debt and the periodic use of short-term debt as a funding source, as well as significant seasonal fluctuations in cash needs.

The Company intends to utilize operating cash flows, as well as FFB borrowings, commercial paper, lines of credit, bank notes, and external securities issuances, as market conditions permit, and equity contributions from Southern Company to fund its short-term capital needs. The Company has substantial cash flow from operating activities and access to the capital markets and financial institutions to meet short-term liquidity needs.

At December 31, 2016, the Company had approximately $3 million of cash and cash equivalents. A committed credit arrangement with banks at December 31, 2016 was $1.75 billion of which $1.73 billion was unused. This credit arrangement expires in 2020.

This bank credit arrangement contains a covenant that limits debt levels and contains a cross acceleration provision to other indebtedness (including guarantee obligations) of the Company. Such cross acceleration provision to other indebtedness would trigger an event of default if the Company defaulted on indebtedness, the payment of which was then accelerated. At December 31, 2016, the Company was in compliance with this covenant. This bank credit arrangement does not contain a material adverse change clause at the time of borrowing.

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

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

A portion of the unused credit with banks is allocated to provide liquidity support to the Company's pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2016 was approximately $868 million. In addition, at December 31, 2016, the Company had $250 million of fixed rate pollution control revenue bonds outstanding that were required to be reoffered within the next 12 months.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional electric operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each traditional electric operating company under these arrangements are several and there is no cross-affiliate credit support. Commercial paper is included in notes payable in the balance sheets.

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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, 2016:					
Commercial paper	$ 392	1.1 %	$ 87	0.8 %	$ 443
December 31, 2015:					
Commercial paper	$ 158	0.6 %	$ 234	0.3 %	$ 678
Short-term bank debt	—	— %	62	0.8 %	250
Total	$ 158	0.6 %	$ 296	0.4 %	
December 31, 2014:					
Commercial paper	$ 156	0.3 %	$ 280	0.2 %	$ 703
Short-term bank debt	—	— %	56	0.9 %	400
Total	$ 156	0.3 %	$ 336	0.3 %	

(*) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2016, 2015, and 2014.

The Company believes the need for working capital can be adequately met by utilizing the commercial paper program, lines of credit, short-term bank notes, and operating cash flows.

Financing Activities

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

Senior Notes

In March 2016, the Company issued $325 million aggregate principal amount of Series 2016A 3.25% Senior Notes due April 1, 2026 and $325 million aggregate principal amount of Series 2016B 2.40% Senior Notes due April 1, 2021. An amount equal to the proceeds from the Series 2016A 3.25% Senior Notes due April 1, 2026 is being allocated to eligible green expenditures, including financing of or investments in solar generating facilities or electric vehicle charging infrastructure, or payments under PPAs served by solar or wind generating facilities. The proceeds from the Series 2016B 2.40% Senior Notes due April 1, 2021 were used to repay at maturity $250 million aggregate principal amount of the Company's Series 2013B Floating Rate Senior Notes due March 15, 2016, to repay a portion of the Company's short-term indebtedness, and for general corporate purposes, including the Company's continuous construction program.

In April 2016, the Company's $250 million aggregate principal amount of Series 2011B 3.00% Senior Notes were repaid at maturity.

In August 2016, the Company's $200 million aggregate principal amount of Series 2013C Floating Rate Senior Notes were repaid at maturity.

Pollution Control Revenue Bonds

In January 2016, $4.085 million aggregate principal amount of Savannah Economic Development Authority Pollution Control Revenue Bonds (Savannah Electric and Power Company Project), First Series 1993 were repaid at maturity.

DOE Loan Guarantee Borrowings

In June and December 2016, the Company made additional borrowings under the FFB Credit Facility in an aggregate principal amount of $300 million and $125 million, respectively. The interest rate applicable to the $300 million principal amount is 2.571% and the interest rate applicable to the $125 million principal amount is 3.142%, both for interest periods that extend to the final maturity date of February 20, 2044. The proceeds were used to reimburse the Company for Eligible Project Costs relating to the construction of Plant Vogtle Units 3 and 4.

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Under the Loan Guarantee Agreement, the Company is subject to customary events of default, as well as cross-defaults to other indebtedness and events of default relating to any failure to make payments under the engineering, procurement, and construction contract, as amended, relating to Plant Vogtle Units 3 and 4 or certain other agreements providing intellectual property rights for Plant Vogtle Units 3 and 4. The Loan Guarantee Agreement also includes events of default specific to the DOE loan guarantee program, including the failure of the Company or Southern Nuclear to comply with requirements of law or DOE loan guarantee program requirements. In the event certain mandatory prepayment events occur, the FFB's commitment to make further advances under the FFB Credit Facility will terminate and the Company will be required to prepay the outstanding principal amount of all borrowings under the FFB Credit Facility over a period of five years (with level principal amortization). See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information.

Credit Rating Risk

At December 31, 2016, the Company did not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, energy price risk management, transmission, and construction of new generation at Plant Vogtle Units 3 and 4.

The maximum potential collateral requirements under these contracts at December 31, 2016 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB- and/or Baa3	$ 93
Below BBB- and/or Baa3	$ 1,258

Included in these amounts are certain agreements that could require collateral in the event that the Company or Alabama Power 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 January 10, 2017, S&P revised its consolidated credit rating outlook for Southern Company (including the Company) from negative to stable.

Market Price Risk

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

To mitigate future exposure to changes in interest rates, the Company may enter into derivatives designated as hedges. The weighted average interest rate on $1.8 billion of long-term variable interest rate exposure at January 1, 2017 was 1.91%. If the Company sustained a 100 basis point change in interest rates for all long-term variable interest rate exposure, the change would affect annualized interest expense by approximately $18 million at January 1, 2017. See Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements for additional information.

To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, financial hedge contracts for natural gas purchases. The Company continues to manage a fuel-hedging program implemented per the guidelines of the Georgia PSC. The Company had no material change in market risk exposure for the year ended December 31, 2016 when compared to the December 31, 2015 reporting period.

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The changes in fair value of energy-related derivative contracts are substantially attributable to both the volume and the price of natural gas. For the years ended December 31, the changes in fair value of energy-related derivative contracts, the majority of which are composed of regulatory hedges, were as follows:

	2016 Changes	2015 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	$(13)	$ (20)
Contracts realized or settled:		
Swaps realized or settled	(2)	2
Options realized or settled	11	18
Current period changes(*):		
Swaps	31	—
Options	9	(13)
Contracts outstanding at the end of the period, assets (liabilities), net	$36	$ (13)

(*) 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:

	2016	2015
	mmBtu Volume (in millions)	
Commodity – Natural gas swaps	128	—
Commodity – Natural gas options	27	50
Total hedge volume	155	50

The weighted average swap contract cost below market prices was approximately $0.23 per mmBtu as of December 31, 2016. There were no swaps outstanding as of December 31, 2015. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. All natural gas hedge gains and losses are recovered through the Company's fuel cost recovery mechanism.

At December 31, 2016 and 2015, 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. Through December 31, 2015, the Company's fuel-hedging program had a time horizon up to 24 months. Effective January 1, 2016, the Georgia PSC approved changes to the Company's hedging program allowing it to use an array of derivative instruments within a 48-month time horizon. Hedging gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery mechanism. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

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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 of the fair value hierarchy. 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, 2016 were as follows:

	Fair Value Measurements December 31, 2016		
	Total	Maturity	
	Fair Value	Year 1	Years 2&3
	(in millions)		
Level 1	$ —	$ —	$ —
Level 2	36	28	8
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$ 36	$ 28	$ 8

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

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to total $2.6 billion for 2017, $2.7 billion for 2018, $2.1 billion for 2019, $1.9 billion for 2020, and $1.7 billion for 2021. These amounts include expenditures of approximately $0.7 billion, $0.5 billion, $0.3 billion, and $0.1 billion for the construction of Plant Vogtle Units 3 and 4 in 2017, 2018, 2019, and 2020, respectively. These amounts also include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. Estimated capital expenditures to comply with environmental statutes and regulations included in these amounts are $0.4 billion, $0.3 billion, $0.1 billion, $0.2 billion, and $0.2 billion for 2017, 2018, 2019, 2020, and 2021, respectively. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's final rules and guidelines or future state plans that would limit CO_2 emissions from new, existing, 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 and monitoring of ash ponds in accordance with the CCR Rule, which are reflected in 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 activities, are estimated to be $0.3 billion for 2017 and $0.2 billion per year for 2018 through 2021. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing generating units, to meet regulatory requirements; changes in FERC rules and regulations; Georgia PSC approvals; changes in the expected environmental compliance program; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. See Note 3 to the financial statements under "Retail Regulatory Matters – Nuclear Construction" for information regarding additional factors that may impact construction expenditures.

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

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

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, other purchase commitments, and trusts are

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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

Contractual obligations at December 31, 2016 were as follows:

	2017	2018-2019	2020-2021	After 2021	Total
	(in millions)				
Long-term debt[(a)] —					
Principal	$450	$1,250	$413	$8,533	$10,646
Interest	383	698	628	5,112	6,821
Preferred and preference stock dividends[(b)]	17	35	35	—	87
Financial derivative obligations[(c)]	1	6	1	—	8
Operating leases[(d)]	19	22	17	15	73
Capital leases[(d)]	9	17	7	—	33
Purchase commitments —					
Capital[(e)]	2,412	4,347	2,941	—	9,700
Fuel[(f)]	1,628	1,681	878	6,320	10,507
Purchased power[(g)]	320	595	539	2,543	3,997
Other[(h)]	108	141	126	361	736
Trusts —					
Nuclear decommissioning[(i)]	5	11	11	99	126
Pension and other postretirement benefit plans[(j)]	46	90	—	—	136
Total	$5,398	$8,893	$5,596	$22,983	$42,870

(a) All amounts are reflected based on final maturity dates except for amounts related to FFB borrowings. As it relates to the FFB borrowings, the final maturity date is February 20, 2044; however, principal amortization is reflected beginning in 2020. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information. The Company plans to continue, when economically feasible, to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2017, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts (shown separately).

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

(c) Includes derivative liabilities related to energy-related derivatives. For additional information, see Notes 1 and 11 to the financial statements.

(d) Excludes PPAs that are accounted for as leases and included in "Purchased power."

(e) The Company provides estimated capital expenditures for a five-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, 2016, significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" and "Retail Regulatory Matters – Nuclear Construction" 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, 2016.

(g) Estimated minimum long-term obligations for various PPA purchases from gas-fired, biomass, and wind-powered facilities. Includes a total of $292 million of biomass PPAs that is contingent upon the counterparties meeting specified contract dates for commercial operation. Subsequent to December 31, 2016, the specified contract dates for commercial operation were extended from 2017 to 2019 and may change further as a result of regulatory action. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Renewables" herein for additional information.

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

(i) Projections of nuclear decommissioning trust fund contributions for Plant Hatch and Plant Vogtle Units 1 and 2 are based on the 2013 ARP. See Note 1 to the financial statements under "Nuclear Decommissioning" for additional information.

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

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Cautionary Statement Regarding Forward-Looking Statements

The Company's 2016 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning regulated rates, customer and sales growth, economic conditions, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, pending or potential litigation matters, access to sources of capital, projections for the qualified pension plan, postretirement benefit plans, and nuclear decommissioning trust fund contributions, financing activities, completion dates of construction projects, filings with state and federal regulatory authorities, impact of the PATH Act, federal income tax benefits, 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 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, including potential tax reform legislation, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries;
- 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, construction, and operation of facilities, which include the development and construction of generating facilities with designs that have not been finalized or previously constructed;
- the ability to construct facilities in accordance with the requirements of permits and licenses, to satisfy any environmental performance standards and the requirements of tax credits and other incentives, and to integrate facilities into the Southern Company system upon completion of construction;
- investment performance of the Company's employee and retiree benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate cases related to fuel and other cost recovery mechanisms;
- the ability to successfully operate generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
- legal proceedings and regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals and NRC actions;
- the inherent risks involved in operating and constructing nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, and financial risks;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;

- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from cyber intrusion or terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts;

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- 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 foreign currency exchange rates, counterparty performance, and the economy in general, as well as potential impacts on the benefits of the DOE loan guarantees;
- the ability of the Company to obtain additional generating capacity (or sell excess generating capacity) at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, 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.

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STATEMENTS OF INCOME
For the Years Ended December 31, 2016, 2015, and 2014
Georgia Power Company 2016 Annual Report

	2016	2015	2014
	(in millions)		
Operating Revenues:			
Retail revenues	$7,772	$7,727	$8,240
Wholesale revenues, non-affiliates	175	215	335
Wholesale revenues, affiliates	42	20	42
Other revenues	394	364	371
Total operating revenues	8,383	8,326	8,988
Operating Expenses:			
Fuel	1,807	2,033	2,547
Purchased power, non-affiliates	361	289	287
Purchased power, affiliates	518	575	701
Other operations and maintenance	1,960	1,844	1,902
Depreciation and amortization	855	846	846
Taxes other than income taxes	405	391	409
Total operating expenses	5,906	5,978	6,692
Operating Income	2,477	2,348	2,296
Other Income and (Expense):			
Interest expense, net of amounts capitalized	(388)	(363)	(348)
Other income (expense), net	38	61	23
Total other income and (expense)	(350)	(302)	(325)
Earnings Before Income Taxes	2,127	2,046	1,971
Income taxes	780	769	729
Net Income	1,347	1,277	1,242
Dividends on Preferred and Preference Stock	17	17	17
Net Income After Dividends on Preferred and Preference Stock	$1,330	$1,260	$1,225

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

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STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2016, 2015, and 2014
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	2016	2015	2014
	(in millions)		
Net Income	$1,347	$1,277	$1,242
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $-, $(6), and $(3), respectively	—	(9)	(5)
Reclassification adjustment for amounts included in net income, net of tax of $2, $1, and $1, respectively	2	2	2
Total other comprehensive income (loss)	2	(7)	(3)
Comprehensive Income	$1,349	$1,270	$1,239

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2016, 2015, and 2014
Georgia Power Company 2016 Annual Report

	2016	2015	2014
	(in millions)		
Operating Activities:			
Net income	$1,347	$1,277	$1,242
Adjustments to reconcile net income			
to net cash provided from operating activities —			
Depreciation and amortization, total	1,063	1,029	1,019
Deferred income taxes	383	173	352
Allowance for equity funds used during construction	(48)	(40)	(45)
Retail fuel cost over-recovery — long-term	—	106	(44)
Pension and postretirement funding	(287)	(7)	(156)
Settlement of asset retirement obligations	(123)	(29)	(12)
Other deferred charges — affiliated	(111)	—	—
Other, net	(10)	10	70
Changes in certain current assets and liabilities —			
-Receivables	60	187	(248)
-Fossil fuel stock	104	37	303
-Prepaid income taxes	—	89	(216)
-Other current assets	(38)	(62)	(37)
-Accounts payable	(42)	(259)	16
-Accrued taxes	131	25	17
-Accrued compensation	(5)	(17)	62
-Other current liabilities	1	(2)	40
Net cash provided from operating activities	2,425	2,517	2,363
Investing Activities:			
Property additions	(2,223)	(2,091)	(2,023)
Nuclear decommissioning trust fund purchases	(808)	(985)	(671)
Nuclear decommissioning trust fund sales	803	980	669
Cost of removal, net of salvage	(83)	(71)	(65)
Change in construction payables, net of joint owner portion	(35)	217	(54)
Prepaid long-term service agreements	(34)	(66)	(70)
Sale of property	10	70	7
Other investing activities	23	2	1
Net cash used for investing activities	(2,347)	(1,944)	(2,206)
Financing Activities:			
Increase (decrease) in notes payable, net	234	2	(891)
Proceeds —			
Senior notes	650	500	—
FFB loan	425	1,000	1,200
Pollution control revenue bonds issuances and remarketings	—	409	40
Capital contributions from parent company	594	62	549
Short-term borrowings	—	250	—
Redemptions and repurchases —			
Senior notes	(700)	(1,175)	—
Pollution control revenue bonds	(4)	(268)	(37)
Short-term borrowings	—	(250)	—

Payment of common stock dividends	(1,305)	(1,034)	(954)
Other financing activities	(36)	(26)	(70)
Net cash used for financing activities	(142)	(530)	(163)
Net Change in Cash and Cash Equivalents	(64)	43	(6)
Cash and Cash Equivalents at Beginning of Year	67	24	30
Cash and Cash Equivalents at End of Year	$3	$67	$24
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $20, $16, and $18 capitalized, respectively)	$375	$353	$319
Income taxes (net of refunds)	170	506	507
Noncash transactions —			
Accrued property additions at year-end	336	387	154
Capital lease obligation	—	149	—

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

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BALANCE SHEETS
At December 31, 2016 and 2015
Georgia Power Company 2016 Annual Report

Assets	2016	2015
	(in millions)	
Current Assets:		
Cash and cash equivalents	$3	$67
Receivables —		
Customer accounts receivable	523	541
Unbilled revenues	224	188
Joint owner accounts receivable	57	227
Income taxes receivable, current	—	114
Other accounts and notes receivable	81	57
Affiliated	18	18
Accumulated provision for uncollectible accounts	(3)	(2)
Fossil fuel stock	298	402
Materials and supplies	479	449
Prepaid expenses	105	230
Other regulatory assets, current	193	213
Other current assets	38	19
Total current assets	2,016	2,523
Property, Plant, and Equipment:		
In service	33,841	31,841
Less accumulated provision for depreciation	11,317	10,903
Plant in service, net of depreciation	22,524	20,938
Other utility plant, net	—	171
Nuclear fuel, at amortized cost	569	572
Construction work in progress	4,939	4,775
Total property, plant, and equipment	28,032	26,456
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	60	64
Nuclear decommissioning trusts, at fair value	814	775
Miscellaneous property and investments	46	43
Total other property and investments	920	882
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	676	679
Other regulatory assets, deferred	2,774	2,152
Other deferred charges and assets	417	173
Total deferred charges and other assets	3,867	3,004
Total Assets	$34,835	$32,865

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

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BALANCE SHEETS
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Liabilities and Stockholder's Equity	2016	2015
	(in millions)	
Current Liabilities:		
Securities due within one year	$460	$712
Notes payable	391	158
Accounts payable —		
Affiliated	438	411
Other	589	750
Customer deposits	265	264
Accrued taxes —		
Accrued income taxes	17	12
Other accrued taxes	390	325
Accrued interest	106	99
Accrued compensation	224	205
Asset retirement obligations, current	299	179
Other regulatory liabilities, current	31	16
Over recovered regulatory clause revenues, current	84	10
Other current liabilities	182	154
Total current liabilities	3,476	3,295
Long-Term Debt (See accompanying statements)	10,225	9,616
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	6,000	5,627
Deferred credits related to income taxes	121	105
Accumulated deferred investment tax credits	256	204
Employee benefit obligations	703	949
Asset retirement obligations, deferred	2,233	1,737
Other deferred credits and liabilities	199	347
Total deferred credits and other liabilities	9,512	8,969
Total Liabilities	23,213	21,880
Preferred Stock (See accompanying statements)	45	45
Preference Stock (See accompanying statements)	221	221
Common Stockholder's Equity (See accompanying statements)	11,356	10,719
Total Liabilities and Stockholder's Equity	$34,835	$32,865
Commitments and Contingent Matters (See notes)		

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

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STATEMENTS OF CAPITALIZATION
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	2016	2015	2016	2015
	(in millions)		(percent of total)	
Long-Term Debt:				
Long-term notes payable —				
Variable rates (0.76% to 0.83% at 1/1/16) due 2016	$—	$450		
3.00% due 2016	—	250		
5.70% due 2017	450	450		
1.95% to 5.40% due 2018	748	747		
4.25% due 2019	500	502		
2.40% due 2021	325	—		
2.85% to 5.95% due 2022-2043	4,175	3,850		
Total long-term notes payable	6,198	6,249		
Other long-term debt —				
Pollution control revenue bonds —				
1.38% to 4.00% due 2022-2049	952	952		
Variable rate (0.22% at 1/1/16) due 2016	—	4		
Variable rates (0.77% to 0.87% at 1/1/17) due 2022-2053	868	868		
FFB loans —				
2.57% to 3.86% due 2020	44	37		
2.57% to 3.86% due 2021	44	37		
2.57% to 3.86% due 2022-2044	2,537	2,126		
Total other long-term debt	4,445	4,024		
Capitalized lease obligations	169	183		
Unamortized debt premium (discount), net	(10)	(10)		
Unamortized debt issuance expense	(117)	(118)		
Total long-term debt (annual interest requirement — $402 million)	10,685	10,328		
Less amount due within one year	460	712		
Long-term debt excluding amount due within one year	10,225	9,616	46.8 %	46.7 %
Preferred and Preference Stock:				
Non-cumulative preferred stock				
$25 par value — 6.125%				
Authorized — 50,000,000 shares				
Outstanding — 1,800,000 shares	45	45		
Non-cumulative preference stock				
$100 par value — 6.50%				
Authorized — 15,000,000 shares				
Outstanding — 2,250,000 shares	221	221		
Total preferred and preference stock (annual dividend requirement — $17 million)	266	266	1.2	1.3
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized — 20,000,000 shares				
Outstanding — 9,261,500 shares	398	398		
Paid-in capital	6,885	6,275		
Retained earnings	4,086	4,061		

Accumulated other comprehensive loss	(13)	(15)		
Total common stockholder's equity	11,356	10,719	52.0	52.0
Total Capitalization	$21,847	$20,601	100.0%	100.0%

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

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STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2016, 2015, and 2014
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	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
	(in millions)					
Balance at December 31, 2013	9	$ 398	$ 5,633	$ 3,565	$ (5)	$ 9,591
Net income after dividends on preferred and preference stock	—	—	—	1,225	—	1,225
Capital contributions from parent company	—	—	563	—	—	563
Other comprehensive income (loss)	—	—	—	—	(3)	(3)
Cash dividends on common stock	—	—	—	(954)	—	(954)
Other	—	—	—	(1)	—	(1)
Balance at December 31, 2014	9	398	6,196	3,835	(8)	10,421
Net income after dividends on preferred and preference stock	—	—	—	1,260	—	1,260
Capital contributions from parent company	—	—	79	—	—	79
Other comprehensive income (loss)	—	—	—	—	(7)	(7)
Cash dividends on common stock	—	—	—	(1,034)	—	(1,034)
Balance at December 31, 2015	9	398	6,275	4,061	(15)	10,719
Net income after dividends on preferred and preference stock	—	—	—	1,330	—	1,330
Capital contributions from parent company	—	—	610	—	—	610
Other comprehensive income (loss)	—	—	—	—	2	2
Cash dividends on common stock	—	—	—	(1,305)	—	(1,305)
Balance at December 31, 2016	9	$ 398	$ 6,885	$ 4,086	$ (13)	$ 11,356

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

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Georgia Power Company 2016 Annual Report

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Georgia Power Company (the Company) is a wholly-owned subsidiary of Southern Company, which is the parent company of the Company and three other traditional electric operating companies, as well as Southern Power, Southern Company Gas (as of July 1, 2016), SCS, Southern LINC, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, PowerSecure, Inc. (PowerSecure) (as of May 9, 2016), and other direct and indirect subsidiaries. The traditional electric operating companies – the Company, Alabama Power, Gulf Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. The Company provides electric service to retail customers within its traditional service territory located within the State of Georgia and to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. Southern Company Gas distributes natural gas through utilities in seven states and is involved in several other complementary businesses including gas marketing services, wholesale gas services, and gas midstream operations. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. Southern LINC provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases and for other electric services. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants, including the Company's Plant Hatch and Plant Vogtle. PowerSecure is a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure. The equity method is used for subsidiaries in which the Company has significant influence but does not control.

The Company is subject to regulation by the FERC and the Georgia PSC. As such, the Company's financial statements reflect the effects of rate regulation in accordance with GAAP and comply with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

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

Recently Issued Accounting Standards

In 2014, the FASB issued ASC 606, Revenue from Contracts with Customers, replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the guidance is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

While the Company expects most of its revenue to be included in the scope of ASC 606, it has not fully completed its evaluation of such arrangements. The majority of the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term. For such arrangements, the Company generally expects that the revenue from contracts with these customers will continue to be equivalent to the electricity supplied and billed in that period (including unbilled revenues) and the adoption of ASC 606 will not result in a significant shift in the timing of revenue recognition for such sales.

The Company's ongoing evaluation of other revenue streams and related contracts includes longer term contractual commitments and unregulated sales to customers. Some revenue arrangements, such as certain PPAs and alternative revenue programs, are expected to be excluded from the scope of ASC 606 and therefore, be accounted for and presented separately from revenues under ASC 606 on the Company's financial statements. In addition, the power and utilities industry is currently addressing other specific industry issues, including the applicability of ASC 606 to contributions in aid of construction (CIAC). If final implementation guidance indicates CIAC will be accounted for under ASC 606 and offsetting regulatory treatment is not permitted, it is expected to have a material impact on the Company's financial statements.

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The new standard is effective for interim and annual reporting periods beginning after December 15, 2017. The Company must select a transition method to be applied either retrospectively to each prior reporting period presented or retrospectively with a cumulative effect adjustment to retained earnings at the date of initial adoption. As the ultimate impact of the new standard has not yet been determined, the Company has not elected its transition method.
On February 25, 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842) (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company is currently evaluating the new standard and has not yet determined its ultimate impact; however, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.
On March 30, 2016, the FASB issued ASU No. 2016-09, Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting (ASU 2016-09). ASU 2016-09 changes the accounting for income taxes and the cash flow presentation for share-based payment award transactions effective for fiscal years beginning after December 15, 2016. The new guidance requires all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation to be recognized as income tax expense or benefit in the income statement. Previously, the Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities rather than net cash provided from financing activities on the statement of cash flows. The Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. The Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of the Company. See Notes 5, 8, and 12 for disclosures impacted by ASU 2016-09.
On October 24, 2016, the FASB issued ASU No. 2016-16, Income Taxes (Topic 740), Intra-Entity Transfers of Assets Other Than Inventory (ASU 2016-16). Current GAAP prohibits the recognition of current and deferred income taxes for an affiliate asset transfer until the asset has been sold to an outside party. ASU 2016-16 requires an entity to recognize the income tax consequences of an affiliate transfer of an asset other than inventory when the transfer occurs. ASU 2016-16 is effective for annual reporting periods beginning after December 15, 2017 and interim periods within those annual periods. The amendments will be applied on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. The Company is currently assessing the impact of the standard on its financial statements and has not yet determined its ultimate impact.

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 $606 million, $585 million, and $555 million in 2016, 2015, and 2014, 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, operations, and construction management. Costs for these services amounted to $666 million, $681 million, and $643 million in 2016, 2015, and 2014, respectively.

The Company has entered into several PPAs with Southern Power for capacity and energy. Expenses associated with these PPAs were $265 million, $179 million, and $144 million in 2016, 2015, and 2014, respectively. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

The Company has a joint ownership agreement with Gulf Power under which Gulf Power owns a 25% portion of Plant Scherer Unit 3. Under this agreement, the Company operates Plant Scherer Unit 3 and Gulf Power reimburses the Company for its 25% proportionate share of the related non-fuel expenses, which were $8 million, $12 million, and $9 million in 2016, 2015, and 2014, respectively. See Note 4 for additional information.

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In 2014, prior to Southern Company's acquisition of PowerSecure on May 9, 2016, the Company entered into agreements with PowerSecure to build solar power generation facilities at two U.S. Army bases, as approved by the Georgia PSC. On October 4, 2016, the two facilities began commercial operation. Payments of approximately $118 million made by the Company to PowerSecure under the agreements since 2014 are included in utility plant in service at December 31, 2016.

On September 1, 2016, Southern Company Gas acquired a 50% equity interest in Southern Natural Gas Company, L.L.C. (SNG). Prior to completion of the acquisition, SCS, as agent for the Company, had entered into a long-term interstate natural gas transportation agreement with SNG. The interstate transportation service provided to the Company by SNG pursuant to this agreement is governed by the terms and conditions of SNG's natural gas tariff and is subject to FERC regulation. For the period subsequent to Southern Company Gas' investment in SNG through December 31, 2016, transportation costs under this agreement were approximately $35 million.

Prior to Southern Company's acquisition of Southern Company Gas, SCS, as agent for the Company, had agreements with certain subsidiaries of Southern Company Gas to purchase natural gas. For the period subsequent to Southern Company's acquisition of Southern Company Gas through December 31, 2016, natural gas purchases made by the Company from Southern Company Gas' subsidiaries were approximately $10 million.

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 2016, 2015, or 2014.

The traditional electric 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 accounting requirements 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.

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

	2016	2015	Note
	(in millions)		
Retiree benefit plans	$1,348	$1,307	(a, j)
Deferred income tax charges	681	683	(b, j)
Loss on reacquired debt	137	150	(c, j)
Asset retirement obligations	893	411	(b, j)
Vacation pay	91	91	(d, j)
Cancelled construction projects	44	56	(e)
Remaining net book value of retired assets	166	171	(f)
Storm damage reserves	206	92	(g)
Other regulatory assets	97	110	(h)
Other cost of removal obligations	3	(31)	(b)
Deferred income tax credits	(121)	(105)	(b, j)
Other regulatory liabilities	(39)	(2)	(i, j)
Total regulatory assets (liabilities), net	$3,506	$2,933	

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

(a) Recovered and amortized over the average remaining service period which may range up to 13 years. See Note 2 for additional information.

(b) Asset retirement and other cost of removal obligations and deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 70 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities. Included in the deferred income tax assets is $26 million for the retiree Medicare drug subsidy, which is recovered and amortized, as approved by the Georgia PSC, through 2022.

(c) Recovered over either the remaining life of the original issue or, if refinanced, over the remaining life of the new issue, which currently does not exceed 36 years.

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

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

(f) Amortized as approved by the Georgia PSC over periods not exceeding 10 years or through 2024. The net book value of Plant Mitchell Unit 3 at December 31, 2016 was $12 million, which will continue to be amortized through December 31, 2019 as provided in the 2013 ARP. Amortization of the remaining net book value of Plant Mitchell Unit 3 at December 31, 2019, which is expected to be approximately $5 million, and $31 million related to obsolete inventories of certain retired units will be determined by the Georgia PSC in the 2019 base rate case. See Note 3 under "Retail Regulatory Matters – Integrated Resource Plan" for additional information.

(g) Previous under-recovery as of December 2013 is recorded and recovered or amortized as approved by the Georgia PSC through 2019. Amortization of $185 million related to the under-recovery from January 2014 through December 2016 will be determined by the Georgia PSC in the 2019 base rate case. See Note 3 for additional information.

(h) Comprised of several components including deferred nuclear outages, environmental remediation, building lease, and demand-side management tariff under-recovery. Deferred nuclear outages are recorded and recovered or amortized over the outage cycles of each nuclear unit, which does not exceed 24 months. The building lease is recorded and recovered or amortized as approved by the Georgia PSC through 2020. The amortization of environmental remediation and demand-side management tariff under-recovery of $46 million at December 31, 2016 will be determined by the Georgia PSC in the 2019 base rate case.

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

(j) Generally not earning a return as they are excluded from rate base or are offset in rate base by a corresponding asset or liability.

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated OCI related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters" for additional information.

Revenues

Wholesale capacity revenues from PPAs are recognized either on a levelized basis over the appropriate contract period or the amount billable under the contract terms. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between the actual recoverable costs and amounts billed in current regulated rates.

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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.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

Federal ITCs utilized are deferred and amortized to income as a credit to reduce depreciation over the average life of the related property. The Company had $83 million in federal ITCs at December 31, 2016 that will expire by 2036. State ITCs are recognized in the period in which the credits are generated. The Company had state investment and other tax credit carryforwards totaling $345 million at December 31, 2016, which will expire between 2019 and 2027 and are expected to be fully utilized by 2023.

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

Property, Plant, and Equipment

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

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

	2016	2015
	(in millions)	
Generation	$16,668	$15,386
Transmission	5,779	5,355
Distribution	9,553	9,151
General	1,813	1,921
Plant acquisition adjustment	28	28
Total plant in service	$33,841	$31,841

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred or performed with the exception of certain generating plant maintenance costs. As mandated by the Georgia PSC, the Company defers and amortizes nuclear refueling outage costs over the unit's operating cycle. The refueling cycles are 18 and 24 months for Plant Vogtle Units 1 and 2 and Plant Hatch Units 1 and 2, respectively.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 2.8% in 2016, 2.7% in 2015, and 2.7% in 2014. Depreciation studies are conducted periodically to update the composite rates that are approved by the Georgia PSC and the FERC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

Under the terms of the 2013 ARP, the Company amortized approximately $14 million in each of 2014, 2015, and 2016 of its remaining regulatory liability related to other cost of removal obligations.

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Asset Retirement Obligations and Other Costs of Removal

AROs are computed as the present value of the estimated ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities. The Company has received accounting guidance from the Georgia PSC allowing the continued accrual and recovery of other retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for future obligations are reflected in the balance sheets as a regulatory liability and amounts to be recovered are reflected in the balance sheets as a regulatory asset.

The ARO liability primarily relates to the Company's ash ponds, landfills, and gypsum cells that are subject to the Disposal of Coal Combustion Residuals from Electric Utilities final rule published by the EPA in April 2015 (CCR Rule). In addition, the Company has retirement obligations related to decommissioning of the Company's nuclear facilities, which include the Company's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2, underground storage tanks, and asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities, including the disposal of polychlorinated biphenyls in certain transformers; leasehold improvements; equipment on customer property; and property associated with the Company's rail lines and natural gas pipelines. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability in the balance sheets as ordered by the Georgia PSC. See "Nuclear Decommissioning" herein for additional information on amounts included in rates.

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

	2016	2015
	(in millions)	
Balance at beginning of year	$1,916	$1,255
Liabilities incurred	—	6
Liabilities settled	(123)	(30)
Accretion	77	56
Cash flow revisions	662	629
Balance at end of year	$2,532	$1,916

The increase in cash flow revisions in 2016 is primarily related to changes to the Company's closure strategy for ash ponds, landfills, and gypsum cells AROs.

The increase in cash flow revisions in 2015 is primarily related to changes to the Company's ash ponds, landfills, and gypsum cells ARO closure dollar and timing estimates associated with the CCR Rule and revisions to the nuclear decommissioning AROs based on the latest decommissioning study.

The cost estimates for AROs related to the CCR Rule are based on information as of December 31, 2016 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. 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 with respect to compliance activities,

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.
Nuclear Decommissioning
The NRC requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has external trust funds (Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. The Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and the Georgia PSC, as well as the IRS. While the

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

The Company records the investment securities held in the Funds at fair value, as disclosed in Note 10, as management believes that fair value best represents the nature of the Funds. Gains and losses, whether realized or unrealized, are recorded in the regulatory liability for AROs in the balance sheets and are not included in net income or OCI. Fair value adjustments and realized gains and losses are determined on a specific identification basis.

The Funds participate in a securities lending program through the managers of the Funds. Under this program, the Funds' investment securities are loaned to institutional investors for a fee. Securities loaned are fully collateralized by cash, letters of credit, and/or securities issued or guaranteed by the U.S. government or its agencies or instrumentalities. As of December 31, 2016 and 2015, approximately $56 million and $76 million, respectively, of the fair market value of the Funds' securities were on loan and pledged to creditors under the Funds' managers' securities lending program. The fair value of the collateral received was approximately $58 million and $78 million at December 31, 2016 and 2015, respectively, and can only be sold by the borrower upon the return of the loaned securities. The collateral received is treated as a non-cash item in the statements of cash flows.

At December 31, 2016, investment securities in the Funds totaled $814 million, consisting of equity securities of $326 million, debt securities of $477 million, and $11 million of other securities. At December 31, 2015, investment securities in the Funds totaled $775 million, consisting of equity securities of $296 million, debt securities of $463 million, and $16 million of other securities. These amounts include the investment securities pledged to creditors and collateral received, and exclude receivables related to investment income and pending investment sales and payables related to pending investment purchases and the lending pool.

Sales of the securities held in the Funds resulted in cash proceeds of $803 million, $980 million, and $669 million in 2016, 2015, and 2014, respectively, all of which were reinvested. For 2016, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $38 million, which included $14 million related to unrealized gains on securities held in the Funds at December 31, 2016. For 2015, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $3 million, which included $26 million related to unrealized losses on securities held in the Funds at December 31, 2015. For 2014, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $44 million, which included an immaterial amount related to unrealized gains and losses on securities held in the Funds at December 31, 2014. While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of the securities and purpose for which the securities were acquired.

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

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Site study cost is the estimate to decommission a specific facility as of the site study year. The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from these estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates. The estimated costs of decommissioning are based on the most current study performed in 2015. The site study costs and external trust funds for decommissioning as of December 31, 2016 based on the Company's ownership interests were as follows:

	Plant Hatch	Plant Vogtle Units 1 and 2
Decommissioning periods:		
Beginning year	2034	2047
Completion year	2075	2079
	(in millions)	
Site study costs:		
Radiated structures	$678	$ 568
Spent fuel management	160	147
Non-radiated structures	64	89
Total site study costs	$902	$ 804
External trust funds	$511	$ 303

For ratemaking purposes, the Company's decommissioning costs are based on the NRC generic estimate to decommission the radioactive portion of the facilities and the site study estimate for spent fuel management as of 2012. Under the 2013 ARP, the Georgia PSC approved annual decommissioning cost for ratemaking of $4 million and $2 million for Plant Hatch and Plant Vogtle Units 1 and 2, respectively. Significant assumptions used to determine the costs for ratemaking include an estimated inflation rate of 2.4% and an estimated trust earnings rate of 4.4%. The Company expects the Georgia PSC to review and adjust, if necessary, the amounts collected in rates for nuclear decommissioning costs in the Company's 2019 base rate case.

Allowance for Funds Used During Construction

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, AFUDC increases the revenue requirement and is recovered over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. For the years 2016, 2015, and 2014, the average AFUDC rates were 6.9%, 6.5%, and 5.6%, respectively, and AFUDC capitalized was $68 million, $56 million, and $62 million, respectively. AFUDC, net of income taxes, was 4.6%, 3.9%, and 4.6% of net income after dividends on preferred and preference stock for 2016, 2015, and 2014, respectively. See Note 3 under "Retail Regulatory Matters – Nuclear Construction" for additional information on the inclusion of construction costs related to Plant Vogtle Units 3 and 4 in rate base effective January 1, 2011.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

Storm Damage Recovery

The Company defers and recovers certain costs related to damages from major storms as mandated by the Georgia PSC. Beginning January 1, 2014, the Company is accruing $30 million annually under the 2013 ARP that is recoverable through base rates. As of December 31, 2016 and December 31, 2015, the balance in the regulatory asset related to storm damage was $206 million and $92 million, respectively, with approximately $30 million included in other regulatory assets, current for both years and approximately $176 million and $62 million included in other regulatory assets, deferred, respectively. The annual recovery amount is expected to be reviewed by the Georgia PSC and adjusted in future regulatory proceedings. As a result of this

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regulatory treatment, costs related to storms are generally not expected to have a material impact on the Company's earnings. See Note 3 under "Retail Regulatory Matters – Storm Damage Recovery" for additional information.

Environmental Remediation Recovery

The Company maintains a reserve for environmental remediation as mandated by the Georgia PSC. In December 2013, the Georgia PSC approved the 2013 ARP including the recovery of approximately $2 million annually through the environmental compliance cost recovery (ECCR) tariff. The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable and reduces the reserve as expenditures are incurred. Any difference between the liabilities accrued and cost recovered through rates is deferred as a regulatory asset or liability. The annual recovery amount is expected to be reviewed by the Georgia PSC and adjusted in future regulatory proceedings. As a result of this regulatory treatment, environmental remediation liabilities generally are not expected to have a material impact on the Company's earnings. As of December 31, 2016, the balance of the environmental remediation liability was $17 million, with approximately $2 million included in other regulatory assets, current and approximately $33 million included as other regulatory assets, deferred. See Note 3 under "Environmental Matters – Environmental Remediation" for additional information.

Cash and Cash Equivalents

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

Materials and Supplies

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

Fuel Inventory

Fuel inventory includes the average cost of coal, natural gas, and oil, as well as transportation and emissions allowances. Fuel is recorded to inventory when purchased and then expensed, at weighted average cost, as used and recovered by the Company through fuel cost recovery rates approved by the Georgia PSC. Emissions allowances granted by the EPA are included in inventory at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities on the balance sheets (included in "Other") and are measured at fair value. See Note 10 for additional information regarding fair value. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Derivative contracts that qualify as cash flow hedges of anticipated transactions or are recoverable through the Georgia PSC-approved fuel-hedging program result in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts that qualify as fair value hedges are marked to market through current period income and are recorded on a net basis in the statements of income. Cash flows from derivatives are classified on the statements of cash flows in the same category as the hedged item. See Note 11 for additional information regarding derivatives.

Beginning in 2016, the Company offsets fair value amounts recognized for multiple derivative instruments executed with the same counterparty under netting arrangements. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2016.

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.

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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). On December 19, 2016, the Company voluntarily contributed $287 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2017. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the Georgia PSC and the FERC. For the year ending December 31, 2017, no other postretirement trust 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:	2016	2015	2014
Pension plans			
Discount rate – benefit obligations	4.65%	4.18%	5.02%
Discount rate – interest costs	3.86	4.18	5.02
Discount rate – service costs	5.03	4.49	5.02
Expected long-term return on plan assets	8.20	8.20	8.20
Annual salary increase	4.46	3.59	3.59
Other postretirement benefit plans			
Discount rate – benefit obligations	4.49%	4.03%	4.85%
Discount rate – interest costs	3.67	4.03	4.85
Discount rate – service costs	4.88	4.39	4.85
Expected long-term return on plan assets	6.27	6.48	6.75
Annual salary increase	4.46	3.59	3.59

Assumptions used to determine benefit obligations:	2016	2015
Pension plans		
Discount rate	4.40%	4.65%
Annual salary increase	4.46	4.46
Other postretirement benefit plans		
Discount rate	4.23%	4.49%
Annual salary increase	4.46	4.46

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.

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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, 2016 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate is Reached
Pre-65	6.50 %	4.50 %	2025
Post-65 medical	5.00	4.50	2025
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, 2016 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$ 55	$ 48
Service and interest costs	2	2

Pension Plans

The total accumulated benefit obligation for the pension plans was $3.5 billion at December 31, 2016 and $3.3 billion at December 31, 2015. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2016 and 2015 were as follows:

	2016	2015
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$ 3,615	$ 3,781
Service cost	70	73
Interest cost	136	154
Benefits paid	(164)	(188)
Actuarial (gain) loss	143	(205)
Balance at end of year	3,800	3,615
Change in plan assets		
Fair value of plan assets at beginning of year	3,196	3,383
Actual return (loss) on plan assets	288	(13)
Employer contributions	301	14
Benefits paid	(164)	(188)
Fair value of plan assets at end of year	3,621	3,196
Accrued liability	$ (179)	$ (419)

At December 31, 2016, the projected benefit obligations for the qualified and non-qualified pension plans were $3.6 billion and $152 million, respectively. All pension plan assets are related to the qualified pension plan.

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Amounts recognized in the balance sheets at December 31, 2016 and 2015 related to the Company's pension plans consist of the following:

	2016	2015
	(in millions)	
Other regulatory assets, deferred	$1,129	$1,076
Other current liabilities	(14)	(13)
Employee benefit obligations	(165)	(406)

Presented below are the amounts included in regulatory assets at December 31, 2016 and 2015 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 2017.

	2016	2015	Estimated Amortization in 2017
	(in millions)		
Prior service cost	$17	$8	$ 3
Net (gain) loss	1,112	1,068	57
Regulatory assets	$1,129	$1,076	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2016 and 2015 are presented in the following table:

	2016	2015
	(in millions)	
Regulatory assets:		
Beginning balance	$1,076	$1,102
Net (gain) loss	99	59
Change in prior service costs	14	—
Reclassification adjustments:		
Amortization of prior service costs	(5)	(9)
Amortization of net gain (loss)	(55)	(76)
Total reclassification adjustments	(60)	(85)
Total change	53	(26)
Ending balance	$1,129	$1,076

Components of net periodic pension cost were as follows:

	2016	2015	2014
	(in millions)		
Service cost	$70	$73	$62
Interest cost	136	154	153
Expected return on plan assets	(258)	(251)	(228)
Recognized net (gain) loss	55	76	41
Net amortization	5	9	10
Net periodic pension cost	$8	$61	$38

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

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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, 2016, estimated benefit payments were as follows:

	Benefit Payments (in millions)
2017	$ 184
2018	190
2019	196
2020	202
2021	206
2022 to 2026	1,126

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2016 and 2015 were as follows:

	2016	2015
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$854	$864
Service cost	6	7
Interest cost	30	34
Benefits paid	(45)	(45)
Actuarial (gain) loss	(1)	(22)
Plan amendment	—	12
Retiree drug subsidy	3	4
Balance at end of year	847	854
Change in plan assets		
Fair value of plan assets at beginning of year	358	395
Actual return (loss) on plan assets	21	(6)
Employer contributions	17	10
Benefits paid	(42)	(41)
Fair value of plan assets at end of year	354	358
Accrued liability	$(493)	$(496)

Amounts recognized in the balance sheets at December 31, 2016 and 2015 related to the Company's other postretirement benefit plans consist of the following:

	2016	2015
	(in millions)	
Other regulatory assets, deferred	$213	$223
Employee benefit obligations	(493)	(496)

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Presented below are the amounts included in regulatory assets at December 31, 2016 and 2015 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 2017.

	2016	2015	Estimated Amortization in 2017
	(in millions)		
Prior service cost	$6	$8	$ 1
Net (gain) loss	207	215	8
Regulatory assets	$213	$223	

The changes in the balance of regulatory assets related to the other postretirement benefit plans for the plan years ended December 31, 2016 and 2015 are presented in the following table:

	2016	2015
	(in millions)	
Regulatory assets:		
Beginning balance	$223	$213
Net (gain) loss	—	9
Change in prior service costs	—	12
Reclassification adjustments:		
Amortization of prior service costs	(1)	—
Amortization of net gain (loss)	(9)	(11)
Total reclassification adjustments	(10)	(11)
Total change	(10)	10
Ending balance	$213	$223

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

	2016	2015	2014
	(in millions)		
Service cost	$6	$7	$6
Interest cost	30	34	34
Expected return on plan assets	(22)	(24)	(25)
Net amortization	10	11	2
Net periodic postretirement benefit cost	$24	$28	$17

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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)		
2017	$54	$ (4)	$ 50
2018	56	(5)	51
2019	58	(5)	53
2020	59	(5)	54
2021	60	(6)	54
2022 to 2026	303	(32)	271

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, 2016 and 2015, along with the targeted mix of assets for each plan, is presented below:

	Target	2016	2015
Pension plan assets:			
Domestic equity	26 %	29 %	30 %
International equity	25	22	23
Fixed income	23	29	23
Special situations	3	2	2
Real estate investments	14	13	16
Private equity	9	5	6
Total	100 %	100%	100%
Other postretirement benefit plan assets:			
Domestic equity	36 %	35 %	34 %
International equity	24	24	27
Domestic fixed income	33	35	25
Global fixed income			8
Special situations	1	1	—
Real estate investments	4	4	4
Private equity	2	1	2
Total	100 %	100%	100%

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

Investment Strategies

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

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

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2016 and 2015. 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, private equity, and special situations investments. Investments in real estate, private equity, and special situations are generally classified as Net Asset Value as a Practical Expedient, since the underlying assets typically do not have publicly available observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. Techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, discounted cash flow analysis, prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals. The fair value of partnerships is determined by aggregating the value of the underlying assets less liabilities.

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The fair values of pension plan assets as of December 31, 2016 and 2015 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. For 2015, investments in special situations were presented in the table below based on the nature of the investment.

	Fair Value Measurements Using				
As of December 31, 2016:	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(*)	$686	$ 317	$ —	$ —	$1,003
International equity(*)	420	380	—	—	800
Fixed income:					
U.S. Treasury, government, and agency bonds	—	201	—	—	201
Mortgage- and asset-backed securities	—	4	—	—	4
Corporate bonds	—	338	—	—	338
Pooled funds	—	179	—	—	179
Cash equivalents and other	340	1	—	—	341
Real estate investments	106	—	—	394	500
Special situations	—	—	—	61	61
Private equity	—	—	—	188	188
Total	$1,552	$ 1,420	$ —	$ 643	$3,615

(*) 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, 2015:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Net Asset Value as a Practical Expedient (NAV)	Total
	(in millions)				
Assets:					
Domestic equity(*)	$565	$ 236	$ —	$ —	$801
International equity(*)	412	343	—	—	755
Fixed income:					
U.S. Treasury, government, and agency bonds	—	157	—	—	157

Mortgage- and asset-backed securities	—	69	—	—	69
Corporate bonds	—	394	—	—	394
Pooled funds	—	173	—	—	173
Cash equivalents and other	—	50	—	—	50
Real estate investments	103	—	—	421	524
Private equity	—	—	—	220	220
Total	$1,080	$ 1,422	$ —	$ 641	$3,143

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(*) 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, 2016 and 2015 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. For 2015, investments in special situations were presented in the table below based on the nature of the investment.

	Fair Value Measurements Using				
As of December 31, 2016:	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(*)	$45	$ 9	$ —	$ —	$54
International equity(*)	11	37	—	—	48
Fixed income:					
U.S. Treasury, government, and agency bonds	—	5	—	—	5
Mortgage- and asset-backed securities	—	—	—	—	—
Corporate bonds	—	9	—	—	9
Pooled funds	—	38	—	—	38
Cash equivalents and other	15	—	—	—	15
Trust-owned life insurance	—	162	—	—	162
Real estate investments	3	—	—	11	14
Special situations	—	—	—	2	2
Private equity	—	—	—	5	5
Total	$74	$ 260	$ —	$ 18	$352

(*) 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.

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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(*)	$30	$ 36	$ —	$ —	$66
International equity(*)	12	41	—	—	53
Fixed income:					
U.S. Treasury, government, and agency bonds	—	5	—	—	5
Mortgage- and asset-backed securities	—	2	—	—	2
Corporate bonds	—	12	—	—	12
Pooled funds	—	30	—	—	30
Cash equivalents and other	10	6	—	—	16
Trust-owned life insurance	—	158	—	—	158
Real estate investments	3	—	—	12	15
Private equity	—	—	—	7	7
Total	$55	$ 290	$ —	$ 19	$364

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

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 2016, 2015, and 2014 were $27 million, $26 million, and $25 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

In 2011, plaintiffs filed a putative class action against the Company in the Superior Court of Fulton County, Georgia alleging that the Company's collection in rates of municipal franchise fees (all of which are remitted to municipalities) exceeded the amounts allowed in orders of the Georgia PSC and alleging certain state tort law claims. On November 16, 2016, the Georgia Court of Appeals reversed the trial court's previous dismissal of the case and remanded the case to the trial court for further proceedings. The Company has filed a petition for writ of certiorari with the Georgia Supreme Court. The Company believes the plaintiffs' claims have no merit and intends to vigorously defend itself in this matter. The ultimate outcome of this matter cannot be determined at this time.

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.

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Environmental Matters

Environmental Remediation

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

The Company's environmental remediation liability as of December 31, 2016 was $17 million. The Company has been designated or identified as a potentially responsible party at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act, and assessment and potential cleanup of such sites is expected.

The ultimate outcome of these matters cannot be determined at this time; however, as a result of the Company's regulatory treatment for environmental remediation expenses described in Note 1 under "Environmental Remediation Recovery," these matters are not expected to have a material impact on the Company's financial statements.

Nuclear Fuel Disposal Costs

Acting through the DOE and pursuant to the Nuclear Waste Policy Act of 1982, the U.S. government entered into contracts with the Company that require the DOE to dispose of spent nuclear fuel and high level radioactive waste generated at Plant Hatch and Plant Vogtle Units 1 and 2 beginning no later than January 31, 1998. The DOE has yet to commence the performance of its contractual and statutory obligation to dispose of spent nuclear fuel. Consequently, the Company pursued and continues to pursue legal remedies against the U.S. government for its partial breach of contract.

In 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. In March 2015, the Company recovered approximately $18 million, based on its ownership interests, which was credited to accounts where the original costs were charged and reduced rate base, fuel, and cost of service for the benefit of customers.

In 2014, the Company filed additional lawsuits against the U.S. government for the costs of continuing to store spent nuclear fuel at Plant Hatch and Plant Vogtle Units 1 and 2 for the period from January 1, 2011 through December 31, 2013. The damage period was subsequently extended to December 31, 2014. Damages will continue to accumulate until the issue is resolved or storage is provided. No amounts have been recognized in the financial statements as of December 31, 2016 for any potential recoveries from the additional lawsuits. The final outcome of these matters cannot be determined at this time; however, no material impact on the Company's net income is expected.

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

FERC Matters

The Company has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional electric operating companies (including the Company) and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In April 2015, the FERC issued an order finding that the traditional electric 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 electric operating companies and in some adjacent areas. The FERC directed the traditional electric 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 electric operating companies (including the Company) and Southern Power filed a request for rehearing in May 2015 and in June 2015 filed their response with the FERC.

On December 9, 2016, the traditional electric operating companies (including the Company) and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' (including the Company's) and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies (including the Company) and in some adjacent areas. The traditional electric operating companies (including the Company) and Southern Power expect to make a compliance filing within 30 days accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.

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

Retail Regulatory Matters

Rate Plans

Pursuant to the terms and conditions of a settlement agreement related to Southern Company's acquisition of Southern Company Gas approved by the Georgia PSC on April 14, 2016, the 2013 ARP will continue in effect until December 31, 2019, and the Company will be required to file its next base rate case by July 1, 2019. Furthermore, through December 31, 2019, the Company and Atlanta Gas Light Company each will retain their respective merger savings, net of transition costs, as defined in the settlement agreement; through December 31, 2022, such net merger savings applicable to each will be shared on a 60/40 basis with their respective customers; thereafter, all merger savings will be retained by customers.

In accordance with the 2013 ARP, the Georgia PSC approved increases to tariffs effective January 1, 2015 and 2016 as follows: (1) traditional base tariff rates by approximately $107 million and $49 million, respectively; (2) ECCR tariff by approximately $23 million and $75 million, respectively; (3) Demand-Side Management tariffs by approximately $3 million in each year; and (4) Municipal Franchise Fee tariff by approximately $3 million and $13 million, respectively, for a total increase in base revenues of approximately $136 million and $140 million, respectively.

Under the 2013 ARP, the Company's retail ROE is set at 10.95% and earnings are evaluated against a retail ROE range of 10.00% to 12.00%. Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by the Company. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. In 2014, the Company's retail ROE exceeded 12.00%, and the Company refunded to retail customers approximately $11 million in 2016, as approved by the Georgia PSC on February 18, 2016. In 2015, the Company's retail ROE was within the allowed retail ROE range. In 2016, the Company's retail ROE exceeded 12.00%, and the Company expects to refund to retail customers approximately $40 million, subject to review and approval by the Georgia PSC. The ultimate outcome of this matter cannot be determined at this time.

Integrated Resource Plan

On July 28, 2016, the Georgia PSC approved the 2016 IRP including the decertification and retirement of Plant Mitchell Units 3, 4A, and 4B (217 MWs) and Plant Kraft Unit 1 (17 MWs), as well as the decertification of the Intercession City unit (143 MWs total capacity). On August 2, 2016, the Plant Mitchell and Plant Kraft units were retired. On August 31, 2016, the Company sold its 33% ownership interest in the Intercession City unit to Duke Energy Florida, LLC.

Additionally, the Georgia PSC approved the Company's environmental compliance strategy and related expenditures proposed in the 2016 IRP, including measures taken to comply with existing government-imposed environmental mandates, subject to limits on expenditures for Plant McIntosh Unit 1 and Plant Hammond Units 1 through 4.

The Georgia PSC approved the reclassification of the remaining net book value of Plant Mitchell Unit 3 and costs associated with materials and supplies remaining at the unit retirement date to a regulatory asset. Recovery of the unit's net book value will continue through December 31, 2019, as provided in the 2013 ARP. The timing of the recovery of the remaining balance of the unit's net book value as of December 31, 2019 and costs associated with materials and supplies remaining at the unit retirement date was deferred for consideration in the Company's 2019 base rate case.

The Georgia PSC also approved the Renewable Energy Development Initiative to procure an additional 1,200 MWs of renewable resources primarily utilizing market-based prices established through a competitive bidding process with expected in-service dates between 2018 and 2021. Additionally, 200 MWs of self-build capacity for use by the Company was approved, as well as consideration for no more than 200 MWs of capacity as part of a renewable commercial and industrial program.

The Georgia PSC also approved recovery of costs up to $99 million through June 30, 2019 to preserve nuclear as an option at a future generation site in Stewart County, Georgia. The timing of cost recovery will be determined by the Georgia PSC in a future base rate case. The ultimate outcome of this matter cannot be determined at this time.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. In December 2015, the Georgia PSC approved the Company's request to lower annual billings by approximately $350 million effective January 1, 2016. On May 17, 2016, the Georgia PSC approved the Company's request to further lower annual billings by approximately $313 million effective

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June 1, 2016. On December 6, 2016, the Georgia PSC approved the delay of the Company's next fuel case, which was previously scheduled to be filed by February 28, 2017. The Georgia PSC will review the Company's cumulative over or under recovered fuel balance no later than September 1, 2018 and evaluate the need to file a fuel case unless the Company deems it necessary to file a fuel case at an earlier time. Under an Interim Fuel Rider, the Company continues to be allowed to adjust its fuel cost recovery rates prior to the next fuel case if the under recovered fuel balance exceeds $200 million.

The Company's fuel cost recovery mechanism includes costs associated with a natural gas hedging program, as revised and approved by the Georgia PSC, allowing the use of an array of derivative instruments within a 48-month time horizon effective January 1, 2016.

The Company's over recovered fuel balance totaled approximately $84 million at December 31, 2016 and is included in over recovered regulatory clause revenues, current. At December 31, 2015, the Company's over recovered fuel balance totaled approximately $116 million, including $10 million in over recovered regulatory clause revenues, current and $106 million in other deferred credits and liabilities.

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

Storm Damage Recovery

As of December 31, 2016, the balance in the Company's regulatory asset related to storm damage was $206 million. During October 2016, Hurricane Matthew caused significant damage to the Company's transmission and distribution facilities. As of December 31, 2016, the Company had recorded incremental restoration cost related to this hurricane of $121 million, of which approximately $116 million was charged to the storm damage reserve and the remainder was capitalized. The Company is accruing $30 million annually through December 31, 2019, as provided in the 2013 ARP, to the storm damage reserve to cover the operations and maintenance costs of damages from major storms to its transmission and distribution facilities, which is recoverable through base rates. The rate of recovery of storm damage costs after December 31, 2019 is expected to be adjusted in the Company's 2019 base rate case. As a result of this regulatory treatment, costs related to storms are not expected to have a material impact on the Company's financial statements. See Note 1 under "Storm Damage Recovery" for additional information regarding the Company's storm damage reserve.

Nuclear Construction

In 2008, the Company, acting for itself and as agent for Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia (Dalton), acting by and through its Board of Water, Light, and Sinking Fund Commissioners, doing business as Dalton Utilities (collectively, Vogtle Owners), entered into an agreement with a consortium consisting of Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc., which was subsequently acquired by Westinghouse and changed its name to WECTEC Global Project Services Inc. (WECTEC) (Westinghouse and WECTEC, collectively, Contractor), pursuant to which the Contractor agreed to design, engineer, procure, construct, and test two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities at Plant Vogtle (Vogtle 3 and 4 Agreement).

Under the terms of the Vogtle 3 and 4 Agreement, the Vogtle Owners agreed to pay a purchase price subject to certain price escalations and adjustments, including fixed escalation amounts and index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. The Vogtle 3 and 4 Agreement also provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees, subject to an aggregate cap of 10% of the contract price, or approximately $920 million to $930 million. In addition, the Vogtle 3 and 4 Agreement provides for limited cost sharing by the Vogtle Owners for Contractor costs under certain conditions (which the Company has not been notified have occurred) with maximum additional capital costs under this provision attributable to the Company (based on the Company's ownership interest) of approximately $114 million. Each Vogtle Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Contractor under the Vogtle 3 and 4 Agreement. The Company's proportionate share is 45.7%. In the event of certain credit rating downgrades of any Vogtle Owner, such Vogtle Owner will be required to provide a letter of credit or other credit enhancement.

Certain obligations of Westinghouse have been guaranteed by Toshiba Corporation (Toshiba), Westinghouse's parent company. In the event of certain credit rating downgrades of Toshiba, Westinghouse is required to provide letters of credit or other credit enhancement. In December 2015, Toshiba experienced credit rating downgrades and Westinghouse provided the Vogtle Owners with $920 million of letters of credit. These letters of credit remain in place in accordance with the terms of the Vogtle 3 and 4 Agreement.

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On February 14, 2017, Toshiba announced preliminary earnings results for the period ended December 31, 2016, which included a substantial goodwill impairment charge at Westinghouse attributed to increased cost estimates to complete its U.S. nuclear projects, including Plant Vogtle Units 3 and 4. Toshiba also warned that it will likely be in a negative equity position as a result of the charges. At the same time, Toshiba reaffirmed its commitment to its U.S. nuclear projects with implementation of management changes and increased oversight. An inability or failure by the Contractor to perform its obligations under the Vogtle 3 and 4 Agreement could have a material impact on the construction of Plant Vogtle Units 3 and 4.

Under the terms of the Vogtle 3 and 4 Agreement, the Contractor does not have a right to terminate the Vogtle 3 and 4 Agreement for convenience. The Contractor may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including certain Vogtle Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Vogtle Owners, Vogtle Owner insolvency, and certain other events. In the event of an abandonment of work by the Contractor, the maximum liability of the Contractor under the Vogtle 3 and 4 Agreement is increased significantly, but remains subject to limitations. The Vogtle Owners may terminate the Vogtle 3 and 4 Agreement at any time for convenience, provided that the Vogtle Owners will be required to pay certain termination costs.

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4 with a certified capital cost of $4.418 billion. In addition, in 2009 the Georgia PSC approved inclusion of the Plant Vogtle Units 3 and 4 related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows the Company to recover financing costs for nuclear construction projects certified by the Georgia PSC. Financing costs are recovered on all applicable certified costs through annual adjustments to the NCCR tariff by including the related CWIP accounts in rate base during the construction period. The Georgia PSC approved an NCCR tariff of $368 million for 2014, as well as increases to the NCCR tariff of approximately $27 million and $19 million effective January 1, 2015 and 2016, respectively.

The Company is required to file semi-annual Vogtle Construction Monitoring (VCM) reports with the Georgia PSC by February 28 and August 31 each year. In accordance with the 2009 certification order, the Company requested amendments to the Plant Vogtle Units 3 and 4 certificate in both the February 2013 (eighth VCM) and February 2015 (twelfth VCM) filings, when projected construction capital costs to be borne by the Company increased by 5% above the certified costs and estimated in-service dates were extended. In October 2013, the Georgia PSC approved a stipulation (2013 Stipulation) between the Company and the Georgia PSC Staff to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate until the completion of Plant Vogtle Unit 3 or earlier if deemed appropriate by the Georgia PSC and the Company. In April 2015, the Georgia PSC recognized that the certified cost and the 2013 Stipulation did not constitute a cost recovery cap and deemed the amendment requested in the February 2015 filing unnecessary and withdrawn until the completion of construction of Plant Vogtle Unit 3 consistent with the 2013 Stipulation.

On December 31, 2015, Westinghouse and the Vogtle Owners entered into a definitive settlement agreement (Contractor Settlement Agreement) to resolve disputes between the Vogtle Owners and the Contractor under the Vogtle 3 and 4 Agreement, including litigation that was pending in the U.S. District Court for the Southern District of Georgia (Vogtle Construction Litigation). Effective December 31, 2015, the Company, acting for itself and as agent for the other Vogtle Owners, and the Contractor entered into an amendment to the Vogtle 3 and 4 Agreement to implement the Contractor Settlement Agreement. The Contractor Settlement Agreement and the related amendment to the Vogtle 3 and 4 Agreement (i) restrict the Contractor's ability to seek further increases in the contract price by clarifying and limiting the circumstances that constitute nuclear regulatory changes in law; (ii) provide for enhanced dispute resolution procedures; (iii) revise the guaranteed substantial completion dates to June 30, 2019 for Unit 3 and June 30, 2020 for Unit 4; (iv) provide that delay liquidated damages will commence if the nuclear fuel loading date for each unit does not occur by December 31, 2018 for Unit 3 and December 31, 2019 for Unit 4; and (v) provide that the Company, based on its ownership interest, will pay to the Contractor and capitalize to the project cost approximately

$350 million, of which approximately $263 million had been paid as of December 31, 2016. In addition, the Contractor Settlement Agreement provides for the resolution of other open existing items relating to the scope of the project under the Vogtle 3 and 4 Agreement, including cyber security, for which costs are reflected in the Company's current in-service forecast of $5.440 billion. Further, as part of the settlement and Westinghouse's acquisition of WECTEC: (i) Westinghouse engaged Fluor Enterprises, Inc., a subsidiary of Fluor Corporation, as a new construction subcontractor and (ii) the Vogtle Owners, Chicago Bridge & Iron Co, N.V., and The Shaw Group Inc. entered into mutual releases of any and all claims arising out of events or circumstances in connection with the construction of Plant Vogtle Units 3 and 4 that occurred on or before the date of the Contractor Settlement Agreement. On January 5, 2016, the Vogtle Construction Litigation was dismissed with prejudice.

On December 20, 2016, the Georgia PSC voted to approve a settlement agreement (Vogtle Cost Settlement Agreement) resolving the following prudence matters: (i) none of the $3.3 billion of costs incurred through December 31, 2015 and reflected in the fourteenth VCM report will be disallowed from rate base on the basis of imprudence; (ii) the Contractor Settlement Agreement is reasonable and prudent and none of the amounts paid or to be paid pursuant to the Contractor Settlement Agreement should be

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disallowed from rate base on the basis of imprudence; (iii) financing costs on verified and approved capital costs will be deemed prudent provided they are incurred prior to December 31, 2019 and December 31, 2020 for Plant Vogtle Units 3 and 4, respectively; and (iv) (a) the in-service capital cost forecast will be adjusted to $5.680 billion (Revised Forecast), which includes a contingency of $240 million above the Company's current forecast of $5.440 billion, (b) capital costs incurred up to the Revised Forecast will be presumed to be reasonable and prudent with the burden of proof on any party challenging such costs, and (c) the Company would have the burden to show that any capital costs above the Revised Forecast are reasonable and prudent. Under the terms of the Vogtle Cost Settlement Agreement, the certified in-service capital cost for purposes of calculating the NCCR tariff will remain at $4.418 billion. Construction capital costs above $4.418 billion will accrue AFUDC through the date each unit is placed in service. The ROE used to calculate the NCCR tariff was reduced from 10.95% (the ROE rate setting point authorized by the Georgia PSC in the 2013 ARP) to 10.00% effective January 1, 2016. For purposes of the AFUDC calculation, the ROE on costs between $4.418 billion and $5.440 billion will also be 10.00% and the ROE on any amounts above $5.440 billion would be the Company's average cost of long-term debt. If the Georgia PSC adjusts the Company's ROE rate setting point in a rate case prior to Plant Vogtle Units 3 and 4 being placed into retail rate base, then the ROE for purposes of calculating both the NCCR tariff and AFUDC will likewise be 95 basis points lower than the revised ROE rate setting point. If Plant Vogtle Units 3 and 4 are not placed in service by December 31, 2020, then (i) the ROE for purposes of calculating the NCCR tariff will be reduced an additional 300 basis points, or $8 million per month, and may, at the Georgia PSC's discretion, be accrued to be used for the benefit of customers, until such time as the units are placed in service and (ii) the ROE used to calculate AFUDC will be the Company's average cost of long-term debt.

Under the terms of the Vogtle Cost Settlement Agreement, Plant Vogtle Units 3 and 4 will be placed into retail rate base on December 31, 2020 or when placed in service, whichever is later. The Georgia PSC will determine for retail ratemaking purposes the process of transitioning Plant Vogtle Units 3 and 4 from a construction project to an operating plant no later than the Company's base rate case required to be filed by July 1, 2019.

The Georgia PSC has approved fifteen VCM reports covering the periods through June 30, 2016, including construction capital costs incurred, which through that date totaled $3.7 billion. The Company expects to file the sixteenth VCM report, covering the period from July 1 through December 31, 2016, requesting approval of $222 million of construction capital costs incurred during that period, with the Georgia PSC by February 28, 2017. The Company's CWIP balance for Plant Vogtle Units 3 and 4 was approximately $3.9 billion as of December 31, 2016, and the Company had incurred $1.3 billion in financing costs through December 31, 2016.

As of December 31, 2016, the Company had borrowed $2.6 billion related to Plant Vogtle Units 3 and 4 costs through a loan guarantee agreement between the Company and the DOE and a multi-advance credit facility among the Company, the DOE, and the FFB. See Note 6 under "DOE Loan Guarantee Borrowings" for additional information, including applicable covenants, events of default, and mandatory prepayment events.

There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4 at the federal and state level and additional challenges may arise as construction proceeds. Processes are in place that are designed to assure compliance with the requirements specified in the Westinghouse Design Control Document and the combined construction and operating licenses, including inspections by Southern Nuclear and the NRC that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the NRC. Various design and other licensing-based compliance matters, including the timely resolution of Inspections, Tests, Analyses, and Acceptance Criteria and the related approvals by the NRC, may arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs either to the Vogtle Owners or the Contractor or to both.

In addition to Toshiba's reaffirmation of its commitment, the Contractor provided the Company with revised forecasted in-service dates of December 2019 and September 2020 for Plant Vogtle Units 3 and 4, respectively. The

Company is currently reviewing a preliminary summary schedule supporting these dates that ultimately must be reconciled to a detailed integrated project schedule. As construction continues, the risk remains that challenges with Contractor performance including labor productivity, fabrication, delivery, assembly, and installation of plant systems, structures, and components, or other issues could arise and may further impact project schedule and cost. The Company expects the Contractor to employ mitigation efforts and believes the Contractor is responsible for any related costs under the Vogtle 3 and 4 Agreement. The Company estimates its financing costs for Plant Vogtle Units 3 and 4 to be approximately $30 million per month, with total construction period financing costs of approximately $2.5 billion. Additionally, the Company estimates its owner's costs to be approximately $6 million per month, net of delay liquidated damages.

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The revised forecasted in-service dates are within the timeframe contemplated in the Vogtle Cost Settlement Agreement and would enable both units to qualify for production tax credits the IRS has allocated to each of Plant Vogtle Units 3 and 4, which require the applicable unit to be placed in service before 2021. The net present value of the production tax credits is estimated at approximately $400 million per unit.

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

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

4. JOINT OWNERSHIP AGREEMENTS

The Company and Alabama Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 MWs, as well as associated transmission facilities. The capacity of these units is sold equally to the Company and Alabama Power under a power contract. The Company and Alabama Power make payments sufficient to provide for the operating expenses, taxes, interest expense, and a ROE. The Company's share of purchased power totaled $57 million in 2016, $78 million in 2015, and $84 million in 2014 and is included in purchased power, affiliates in the statements of income. The Company accounts for SEGCO using the equity method. See Note 7 under "Guarantees" for additional information.

The Company owns undivided interests in Plants Vogtle, Hatch, Wansley, and Scherer in varying amounts jointly with one or more of the following entities: OPC, MEAG Power, Dalton, Florida Power & Light Company, Jacksonville Electric Authority, and Gulf Power. Under these agreements, the Company has been contracted to operate and maintain the plants as agent for the co-owners and is jointly and severally liable for third party claims related to these plants. In addition, the Company jointly owns the Rocky Mountain pumped storage hydroelectric plant with OPC, which is the operator of the plant. On August 31, 2016, the Company sold its 33% ownership interest in the Intercession City combustion turbine unit to Duke Energy Florida, LLC.

At December 31, 2016, the Company's percentage ownership and investment (exclusive of nuclear fuel) in jointly-owned facilities in commercial operation with the above entities were as follows:

Facility (Type)	Company Ownership		Plant in Service	Accumulated Depreciation	CWIP
			(in millions)		
Plant Vogtle (nuclear)					
Units 1 and 2	45.7	%	$3,545	$ 2,111	$ 74
Plant Hatch (nuclear)	50.1		1,297	585	81
Plant Wansley (coal)	53.5		1,046	308	12
Plant Scherer (coal)					
Units 1 and 2	8.4		258	90	3
Unit 3	75.0		1,203	458	23
Rocky Mountain (pumped storage)	25.4		181	129	—

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

The Company also owns 45.7% of Plant Vogtle Units 3 and 4, which are currently under construction and had a CWIP balance of approximately $3.9 billion as of December 31, 2016. See Note 3 under "Retail Regulatory Matters – Nuclear Construction" for additional information.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and various combined and separate state income tax returns. Under a joint consolidated income tax allocation agreement, each Southern

Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

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Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2016	2015	2014
	(in millions)		
Federal –			
Current	$391	$515	$295
Deferred	319	176	366
	710	691	661
State –			
Current	6	81	82
Deferred	64	(3)	(14)
	70	78	68
Total	$780	$769	$729

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:

	2016	2015
	(in millions)	
Deferred tax liabilities –		
Accelerated depreciation	$5,266	$4,909
Property basis differences	957	1,003
Employee benefit obligations	428	310
Premium on reacquired debt	56	61
Regulatory assets –		
Storm damage reserves	83	37
Employee benefit obligations	546	528
Asset retirement obligations	726	545
Retired assets	55	58
Asset retirement obligations	182	161
Other	83	92
Total	8,382	7,704
Deferred tax assets –		
Federal effect of state deferred taxes	173	150
Employee benefit obligations	661	642
Other property basis differences	105	88
Other deferred costs	100	83
State investment tax credit carryforward	201	216
Federal tax credit carryforward	84	3
Unbilled fuel revenue	47	47
Regulatory liabilities associated with asset retirement obligations	33	60
Asset retirement obligations	908	706
Other	70	82
Total	2,382	2,077
Accumulated deferred income taxes	$6,000	$5,627

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The application of bonus depreciation provisions in current tax law significantly increased deferred tax liabilities related to accelerated depreciation in 2016 and 2015.

At December 31, 2016, tax-related regulatory assets to be recovered from customers were $681 million. These assets are primarily attributable to tax benefits flowed through to customers in prior years and deferred taxes previously recognized at rates lower than the current enacted tax law.

At December 31, 2016, tax-related regulatory liabilities to be credited to customers were $121 million. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law.

In accordance with regulatory requirements, utilized federal ITCs are deferred and amortized over the average life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $10 million in each of 2016, 2015, and 2014. State investment tax credits are recognized in the period in which the credits are generated and totaled $42 million in 2016, $33 million in 2015, and $34 million in 2014. At December 31, 2016, the Company had $83 million in federal ITC carryforwards that will expire by 2036 and $201 million in state ITC carryforwards that will expire between 2019 and 2027.

Effective Tax Rate

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

	2016	2015	2014
Federal statutory rate	35.0 %	35.0 %	35.0 %
State income tax, net of federal deduction	2.1	2.5	2.2
Non-deductible book depreciation	0.8	1.2	1.3
AFUDC equity	(0.8)	(0.7)	(0.8)
Other	(0.4)	(0.4)	(0.7)
Effective income tax rate	36.7 %	37.6 %	37.0 %

On March 30, 2016, the FASB issued ASU 2016-09, which changes the accounting for income taxes for share-based payment award transactions. Entities are required to recognize all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation as income tax expense or benefit in the income statement. The adoption of ASU 2016-09 did not have a material impact on the Company's overall effective tax rate. See Note 1 under "Recently Issued Accounting Standards" for additional information.

Unrecognized Tax Benefits

The Company had no unrecognized tax benefits as of December 31, 2016 and no material changes in unrecognized tax benefits for any year presented.

The Company classifies interest on tax uncertainties as interest expense; however, the Company did not have any accrued interest or penalties for unrecognized tax benefits for any year presented.

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

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013 through 2015 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.

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6. FINANCING
Securities Due Within One Year
A summary of scheduled maturities of long-term debt due within one year at December 31 was as follows:

	2016	2015
	(in millions)	
Senior notes	$450	$700
Pollution control revenue bonds	—	4
Capital leases	10	8
Total	$460	$712

Maturities through 2021 applicable to total long-term debt are as follows: $460 million in 2017; $762 million in 2018; $513 million in 2019; $57 million in 2020; and $376 million in 2021.
Senior Notes
In March 2016, the Company issued $325 million aggregate principal amount of Series 2016A 3.25% Senior Notes due April 1, 2026 and $325 million aggregate principal amount of Series 2016B 2.40% Senior Notes due April 1, 2021. An amount equal to the proceeds from the Series 2016A 3.25% Senior Notes due April 1, 2026 is being allocated to eligible green expenditures, including financing of or investments in solar generating facilities or electric vehicle charging infrastructure, or payments under PPAs served by solar or wind generating facilities. The proceeds from the Series 2016B 2.40% Senior Notes due April 1, 2021 were used to repay at maturity $250 million aggregate principal amount of the Company's Series 2013B Floating Rate Senior Notes due March 15, 2016, to repay a portion of the Company's short-term indebtedness, and for general corporate purposes, including the Company's continuous construction program.
At December 31, 2016 and 2015, the Company had $6.2 billion and $6.3 billion of senior notes outstanding, respectively, which included senior notes due within one year. These senior notes are effectively subordinated to all secured debt of the Company, which aggregated $2.8 billion and $2.4 billion at December 31, 2016 and 2015, respectively. As of December 31, 2016, the Company's secured debt included borrowings of $2.6 billion guaranteed by the DOE and capital lease obligations of $169 million. As of December 31, 2015, the Company's secured debt included borrowings of $2.2 billion guaranteed by the DOE and capital lease obligations of $183 million. See Note 7 and "DOE Loan Guarantee Borrowings" herein for additional information.
Pollution Control Revenue Bonds
Pollution control revenue bond obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bond obligations outstanding at both December 31, 2016 and 2015 was $1.8 billion.
DOE Loan Guarantee Borrowings
Pursuant to the loan guarantee program established under Title XVII of the Energy Policy Act of 2005 (Title XVII Loan Guarantee Program), the Company and the DOE entered into a loan guarantee agreement (Loan Guarantee Agreement) in February 2014, under which the DOE agreed to guarantee the obligations of the Company under a note purchase agreement (FFB Note Purchase Agreement) among the DOE, the Company, and the FFB and a related promissory note (FFB Promissory Note). The FFB Note Purchase Agreement and the FFB Promissory Note provide for a multi-advance term loan facility (FFB Credit Facility), under which the Company may make term loan borrowings through the FFB.
Proceeds of advances made under the FFB Credit Facility are used to reimburse the Company for a portion of certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the Title XVII Loan Guarantee Program (Eligible Project Costs). Aggregate borrowings under the FFB Credit Facility may not exceed the

lesser of (i) 70% of Eligible Project Costs or (ii) approximately $3.46 billion.
All borrowings under the FFB Credit Facility are full recourse to the Company, and the Company is obligated to reimburse the DOE for any payments the DOE is required to make to the FFB under the guarantee. The Company's reimbursement obligations to the DOE are full recourse and secured by a first priority lien on (i) the Company's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor

core) and (ii) the Company's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. There are no restrictions on the Company's ability to grant liens on other property.

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

In connection with its entry into the agreements with the DOE and the FFB, the Company incurred issuance costs of approximately $66 million, which are being amortized over the life of the borrowings under the FFB Credit Facility.

In June and December 2016, the Company made borrowings under the FFB Credit Facility in an aggregate principal amount of $300 million and $125 million, respectively. The interest rate applicable to the $300 million principal amount is 2.571% and the interest rate applicable to the $125 million principal amount is 3.142%, both for an interest period that extends to the final maturity date of February 20, 2044.

At December 31, 2016 and 2015, the Company had $2.6 billion and $2.2 billion of borrowings outstanding under the FFB Credit Facility, respectively. Future advances are subject to satisfaction of customary conditions, as well as certification of compliance with the requirements of the Title XVII Loan Guarantee Program, including accuracy of project-related representations and warranties, delivery of updated project-related information, and evidence of compliance with the prevailing wage requirements of the Davis-Bacon Act of 1931, as amended, and certification from the DOE's consulting engineer that proceeds of the advances are used to reimburse Eligible Project Costs.

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

In the event certain mandatory prepayment events occur, the FFB's commitment to make further advances under the FFB Credit Facility will terminate and the Company will be required to prepay the outstanding principal amount of all borrowings under the FFB Credit Facility over a period of five years (with level principal amortization). Among other things, these mandatory prepayment events include (i) the termination of the Vogtle 3 and 4 Agreement; (ii) cancellation of Plant Vogtle Units 3 and 4 by the Georgia PSC, or by the Company if authorized by the Georgia PSC; and (iii) cost disallowances by the Georgia PSC that could have a material adverse effect on completion of Plant Vogtle Units 3 and 4 or the Company's ability to repay the outstanding borrowings under the FFB Credit Facility. Under certain circumstances, insurance proceeds and any proceeds from an event of taking must be applied to immediately prepay outstanding borrowings under the FFB Credit Facility. The Company also may voluntarily prepay outstanding borrowings under the FFB Credit Facility. Under the FFB Promissory Note, any prepayment (whether mandatory or optional) will be made with a make-whole premium or discount, as applicable.

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

Capital Leases

Assets acquired under capital leases are recorded in the balance sheets as utility plant in service, and the related obligations are classified as long-term debt. At December 31, 2016 and 2015, the Company had a capital lease asset for its corporate headquarters building of $61 million, with accumulated depreciation at December 31, 2016 and 2015 of $33 million and $26 million, respectively. At December 31, 2016 and 2015, the capitalized lease obligation was $28 million and $35 million, respectively, with an annual interest rate of 7.9% for both years. For ratemaking purposes, the Georgia PSC has allowed the lease payments in cost of service with no return on the capital lease asset. The difference between the depreciation and the lease payments allowed for ratemaking purposes is recovered as operating expenses as ordered by the Georgia PSC. The annual operating expense incurred for this capital lease was not material for any year presented.

At December 31, 2016 and 2015, the Company had capital lease assets related to two PPAs with Southern Power of $149 million, with accumulated amortization at December 31, 2016 and 2015 of $19 million and $10 million, respectively. At December 31, 2016 and 2015, the related capitalized lease obligations were $141 million and $148 million, respectively. The annual interest rates range from 10% to 11% for these two capital lease PPAs. For ratemaking purposes, the Georgia PSC has included the capital lease asset amortization in cost of service and the interest in the Company's cost of debt. See Note 1 under "Affiliate Transactions" and Note 7 under "Fuel and Purchased Power Agreements" for additional information.

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Assets Subject to Lien

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

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

Outstanding Classes of Capital Stock

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

Dividend Restrictions

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

Bank Credit Arrangements

At December 31, 2016, the Company had a $1.75 billion committed credit arrangement with banks, of which $1.73 billion was unused. This credit arrangement expires in 2020.

This bank credit arrangement requires payment of commitment fees based on the unused portion of the commitments. Commitment fees average less than 1/4 of 1% for the Company.

This bank credit arrangement contains a covenant that limits the Company's debt levels to 65% of total capitalization, as defined in the agreement. For purposes of this definition, debt excludes certain hybrid securities. At December 31, 2016, the Company was in compliance with the debt limit covenant.

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

A portion of the $1.73 billion unused credit with banks is allocated to provide liquidity support to the Company's pollution control revenue bonds and its commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2016 was $868 million. In addition, at December 31, 2016, the Company had $250 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

The Company makes short-term borrowings primarily through a commercial paper program that has the liquidity support of the Company's committed bank credit arrangement described above. Commercial paper is included in notes payable in the balance sheets.

Details of commercial paper borrowings outstanding were as follows:

	Commercial Paper at the End of the Period	
	Amount Outstanding	Weighted Average Interest

		Rate	
	(in millions)		
December 31, 2016	$392	1.1	%
December 31, 2015	$158	0.6	%

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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 2016, 2015, and 2014, the Company incurred fuel expense of $1.8 billion, $2.0 billion, and $2.5 billion, respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.
The Company has commitments regarding a portion of a 5% interest in the original cost of Plant Vogtle Units 1 and 2 owned by MEAG Power that are in effect until the latter of the retirement of the plant or the latest stated maturity date of MEAG Power's bonds issued to finance such ownership interest. The payments for capacity are required whether or not any capacity is available. The energy cost is a function of each unit's variable operating costs. Portions of the capacity payments relate to costs in excess of MEAG Power's Plant Vogtle Units 1 and 2 allowed investment for ratemaking purposes. The present value of these portions at the time of the disallowance was written off. Generally, the cost of such capacity and energy is included in purchased power, non-affiliates in the statements of income. Capacity payments totaled $11 million, $10 million, and $19 million in 2016, 2015, and 2014, respectively.
The Company has also entered into various long-term PPAs, some of which are accounted for as capital or operating leases. Total capacity expense under PPAs accounted for as operating leases was $217 million, $203 million, and $167 million for 2016, 2015, and 2014, respectively. Estimated total long-term obligations at December 31, 2016 were as follows:

	Affiliate Capital Leases	Affiliate Operating Leases	Non-Affiliate Operating Leases[c]	Vogtle Units 1 and 2 Capacity Payments	Total
	(in millions)				
2017	$22	$ 72	$ 123	$ 8	$225
2018	22	63	126	7	218
2019	23	64	127	6	220
2020	23	65	123	5	216
2021	24	66	124	5	219
2022 and thereafter	204	479	882	43	1,608
Total	$318	$ 809	$ 1,505	$ 74	$2,706
Less: amounts representing executory costs[a]	48				
Net minimum lease payments	270				
Less: amounts representing interest[b]	128				
Present value of net minimum lease payments	$142				

(a) Executory costs such as taxes, maintenance, and insurance (including the estimated profit thereon) are estimated and included in total minimum lease payments.
(b) Calculated using an adjusted incremental borrowing rate to reduce the present value of the net minimum lease payments to fair value.
(c) A total of $197 million of biomass PPAs included under the non-affiliate operating leases is contingent upon the counterparties meeting specified contract dates for commercial operation. Subsequent to December 31, 2016, the specified contract dates for commercial operation were extended from 2017 to 2019 and may change further as a result of regulatory action.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other traditional electric operating companies and Southern Power. Under these agreements, each of the traditional electric 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 electric 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.

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Operating Leases

In addition to the PPA operating leases discussed above, the Company has other operating lease agreements with various terms and expiration dates. Total rent expense was $28 million for 2016, $29 million for 2015, and $28 million for 2014. The Company includes any step rents, fixed escalations, and lease concessions in its computation of minimum lease payments.

As of December 31, 2016, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Railcars	Other	Total
	(in millions)		
2017	$ 12	$ 7	$ 19
2018	6	7	13
2019	3	6	9
2020	3	6	9
2021	2	6	8
2022 and thereafter	2	13	15
Total	$ 28	$ 45	$ 73

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

In addition to the above rental commitments, the Company has obligations upon expiration of certain railcar leases with respect to the residual value of the leased property. These leases have terms expiring through 2024 with maximum obligations under these leases of $32 million. At the termination of the leases, the lessee may either renew the lease, exercise its purchase option, or the property can be sold to a third party. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligations.

Guarantees

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

In addition, in 2013, the Company entered into an agreement that requires the Company to guarantee certain payments of a gas supplier for Plant McIntosh for a period up to 15 years. The guarantee is expected to be terminated if certain events occur within one year of the initial gas deliveries in 2018. In the event the gas supplier defaults on payments, the maximum potential exposure under the guarantee is approximately $43 million.

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

8. STOCK COMPENSATION

Stock-Based Compensation

Stock-based compensation primarily in the form of Southern Company 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, 2016, there were 990 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.

The weighted average grant-date fair value of stock options granted during 2014 derived using the Black-Scholes stock option pricing model was $2.20.

The compensation cost related to the grant of Southern Company stock options to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. Compensation cost and related tax benefits recognized in the Company's financial statements were not material for any year presented. As of December 31, 2016, 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, 2016, 2015, and 2014 was $18 million, $9 million, and $19 million, respectively. No cash proceeds are received by the Company upon the exercise of stock options. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $7 million, $4 million, and $7 million for the years ended December 31, 2016, 2015, and 2014, respectively. Prior to the adoption of ASU 2016-09, the excess tax benefits related to the exercise of stock options were recognized in the Company's financial statements with a credit to equity. Upon the adoption of ASU 2016-09, beginning in 2016, all tax benefits related to the exercise of stock options are recognized in income. As of December 31, 2016, the aggregate intrinsic value for the options outstanding and options exercisable was $46 million and $41 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. 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, 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

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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, 2016, 2015, and 2014, employees of the Company were granted performance share units of 261,434, 236,804, and 176,224, respectively. The weighted average grant-date fair value of TSR-based performance share units granted during 2016, 2015, and 2014, 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 $45.17, $46.41, and $37.54, respectively. The weighted average grant-date fair value of both EPS-based and ROE-based performance share units granted during 2016 and 2015 was $48.84 and $47.78, respectively.

For the years ended December 31, 2016, 2015, and 2014, total compensation cost for performance share units recognized in income was $15 million, $15 million, and $6 million, respectively, with the related tax benefit also recognized in income of $6 million, $6 million, and $2 million, respectively. The compensation cost related to the grant of Southern Company performance share units to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2016, $4 million of total unrecognized compensation cost related to performance share award units will be recognized over a weighted-average period of approximately 22 months.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at Plant Hatch and Plant Vogtle Units 1 and 2. The Act provides funds up to $13.4 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. The Company could be assessed up to $127 million per incident for each licensed reactor it operates but not more than an aggregate of $19 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for the Company, based on its ownership and buyback interests in all licensed reactors, is $247 million per incident, but not more than an aggregate of $37 million to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due no later than September 10, 2018. See Note 4 for additional information on joint ownership agreements.

The Company is a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $1.5 billion for members' operating nuclear generating facilities. Additionally, the Company has NEIL policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $1.25 billion for nuclear losses in excess of the $1.5 billion primary coverage. In April 2014, NEIL introduced a new excess non-nuclear policy providing coverage up to $750 million for non-nuclear losses in excess of the $1.5 billion primary coverage.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. The Company purchases limits based on the projected full cost of replacement power, subject to ownership limitations, and has elected a 12-week deductible waiting period for each facility.

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

Under each of the NEIL policies, members are subject to assessments each year if losses exceed the accumulated funds available to the insurer. The maximum annual assessments for the Company as of December 31, 2016 under the NEIL policies would be $82 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, 2016, 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, 2016:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in millions)			
Assets:				
Energy-related derivatives	$—	$ 44	$ —	$44
Interest rate derivatives	—	2	—	2
Nuclear decommissioning trusts:(*)				
Domestic equity	204	1	—	205
Foreign equity	—	121	—	121
U.S. Treasury and government agency securities	—	71	—	71
Municipal bonds	—	73	—	73
Corporate bonds	—	164	—	164
Mortgage and asset backed securities	—	164	—	164
Other	11	5	—	16
Total	$215	$ 645	$ —	$860
Liabilities:				
Energy-related derivatives	$—	$ 8	$ —	$8

Interest rate derivatives	—	3	—	3
Total	$—	$ 11	$ —	$11

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

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As of December 31, 2015, assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

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

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

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

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. For fair value measurements of the investments within the nuclear decommissioning trusts, external pricing vendors are designated for each asset class with each security specifically assigned a primary pricing source. For investments held within commingled funds, fair value is determined at the end of each business day through the net asset value, which is established by obtaining the underlying securities' individual prices from the primary pricing source. A market price secured from the primary source vendor is then evaluated by management in its valuation of the assets within the trusts. As a general approach, fixed income market pricing vendors gather market data (including indices and market research reports) and integrate relative credit information, observed market movements, and sector news into proprietary pricing models, pricing

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systems, and mathematical tools. Dealer quotes and other market information, including live trading levels and pricing analysts' judgments, are also obtained when available. See Note 1 under "Nuclear Decommissioning" for additional information.

As of December 31, 2016 and 2015, 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:		
2016	$10,516	$11,034
2015	$10,145	$10,480

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on current rates available to the Company.

11. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a net 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 energy-related commodity prices. The Company manages a fuel-hedging program through the use of financial derivative contracts, which is expected to continue to mitigate price volatility. At December 31, 2016 and 2015, 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. Through December 31, 2015, the Company's fuel-hedging program had a time horizon up to 24 months. Effective January 1, 2016, the Georgia PSC approved changes to the Company's hedging program allowing it to use an array of derivative instruments within a 48-month time horizon.

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

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

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

At December 31, 2016, the net volume of energy-related derivative contracts for natural gas positions totaled 155 million mmBtu, all of which expire by 2020, which is the longest hedge date.

In addition to the volume discussed above, the Company enters into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The expected volume of natural gas subject to such a feature is 3 million mmBtu for the Company.

Interest Rate Derivatives

The Company may also enter into interest rate derivatives to hedge exposure to changes in interest rates. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings, with any ineffectiveness recorded directly to earnings. At December 31, 2016, there were no cash flow hedges outstanding. Derivatives related to fixed rate securities are accounted for as fair value hedges, where the derivatives' fair value gains and losses and the hedged items' fair value gains and losses attributable to interest rate risk are both recorded directly to earnings, providing an offset, with any differences representing ineffectiveness.

At December 31, 2016, the following interest rate derivatives were outstanding:

	Notional Amount	Interest Rate Received	Weighted Average Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2016
	(in millions)				(in millions)
Fair Value Hedges of Existing Debt					
	$ 250	5.40%	3-month LIBOR + 4.02%	June 2018	$ —
	500	1.95%	3-month LIBOR + 0.76%	December 2018	(2)
	200	4.25%	3-month LIBOR + 2.46%	December 2019	1
Total	$ 950				$ (1)

The estimated pre-tax gains (losses) that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2017 total $4 million. Deferred gains and losses related to interest rate derivative settlements of cash flow hedges are expected to be amortized into earnings through 2037.

Derivative Financial Statement Presentation and Amounts

The Company enters into energy-related and interest rate derivative contracts that may contain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. At December 31, 2016, fair value amounts of derivative assets and liabilities on the balance sheets are presented net to the extent that there are netting arrangements or similar agreements with the counterparties. At December 31, 2015, the fair value amounts of derivative instruments were presented gross on the balance sheets.

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At December 31, 2016 and 2015, the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

Derivative Category and Balance Sheet Location	2016 Assets	2016 Liabilities	2015 Assets	2015 Liabilities
	(in millions)			
Derivatives designated as hedging instruments for regulatory purposes				
Energy-related derivatives:				
Other current assets/Other current liabilities	$30	$ 1	$2	$ 12
Other deferred charges and assets/Other deferred credits and liabilities	14	7	—	3
Total derivatives designated as hedging instruments for regulatory purposes	$44	$ 8	$2	$ 15
Derivatives designated as hedging instruments in cash flow and fair value hedges				
Interest rate derivatives:				
Other current assets/Other current liabilities	$2	$ —	$5	$ —
Other deferred charges and assets/Other deferred credits and liabilities	—	3	—	6
Total derivatives designated as hedging instruments in cash flow and fair value hedges	$2	$ 3	$5	$ 6
Gross amounts recognized	$46	$ 11	$7	$ 21
Gross amounts offset	$(8)	$ (8)	$(6)	$ (6)
Net amounts recognized in the Balance Sheets(*)	$38	$ 3	$1	$ 15

(*) At December 31, 2015, the fair value amounts for derivative contracts subject to netting arrangements were presented gross on the balance sheet.

Energy-related derivatives not designated as hedging instruments were immaterial on the balance sheets for 2016 and 2015.

At December 31, 2016 and 2015, the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivatives designated as regulatory hedging instruments and deferred were as follows:

Derivative Category	Unrealized Losses Balance Sheet Location	2016	2015	Unrealized Gains Balance Sheet Location	2016	2015
		(in millions)			(in millions)	
Energy-related derivatives:(*)	Other regulatory assets, current	$ —	$ (12)	Other regulatory liabilities, current	$ 29	$ 2
	Other regulatory assets, deferred	—	(3)	Other deferred credits and liabilities	7	—
Total energy-related derivative gains (losses)		$ —	$ (15)		$ 36	$ 2

(*) At December 31, 2016, the unrealized gains and losses for energy-related derivative contracts subject to netting arrangements were presented net on the balance sheet. At December 31, 2015, the unrealized gains and losses for energy-related derivative contracts subject to netting arrangements were presented gross on the balance sheet.

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For the years ended December 31, 2016, 2015, and 2014, the pre-tax effects of interest rate derivatives designated as cash flow hedging instruments on the statements of income were as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)			Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
					Amount		
Derivative Category	2016	2015	2014	Statements of Income Location	2016	2015	2014
	(in millions)				(in millions)		
Interest rate derivatives	$ —	$ (15)	$ (8)	Interest expense, net of amounts capitalized	$(4)	$(3)	$(3)

For the years ended December 31, 2016 and 2015, the pre-tax effects of interest rate derivatives designated as fair value hedging instruments on the statements of income were immaterial on a gross basis for the Company. Furthermore, the pre-tax effect of interest rate derivatives designated as fair value hedging instruments on the Company's statements of income were offset by changes to the carrying value of long-term debt. The gains and losses related to interest rate derivative settlements of fair value hedges are recorded directly to earnings.

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

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2016, the Company's collateral posted with its derivative counterparties was immaterial.

At December 31, 2016, the fair value of derivative liabilities with contingent features, including 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 because of joint and several liability features underlying these derivatives, was immaterial.

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.

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12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2016 and 2015 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
	(in millions)		
March 2016	$1,872	$ 509	$ 269
June 2016	2,051	656	349
September 2016	2,698	1,054	599
December 2016	1,762	258	113
March 2015	$1,978	$ 454	$ 236
June 2015	2,016	554	277
September 2015	2,691	964	551
December 2015	1,641	376	196

In accordance with the adoption of ASU 2016-09 (see Note 1 under "Recently Issued Accounting Standards"), previously reported amounts for income tax expense were reduced by $1 million in the third quarter 2016, $2 million in the second quarter 2016, and $1 million in the first quarter 2016.

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

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	2016	2015	2014	2013	2012
Operating Revenues (in millions)	$ 8,383	$ 8,326	$ 8,988	$ 8,274	$ 7,998
Net Income After Dividends on Preferred and Preference Stock (in millions)	$ 1,330	$ 1,260	$ 1,225	$ 1,174	$ 1,168
Cash Dividends on Common Stock (in millions)	$ 1,305	$ 1,034	$ 954	$ 907	$ 983
Return on Average Common Equity (percent)	12.05	11.92	12.24	12.45	12.76
Total Assets (in millions)[(a)(b)]	$ 34,835	$ 32,865	$ 30,872	$ 28,776	$ 28,618
Gross Property Additions (in millions)	$ 2,314	$ 2,332	$ 2,146	$ 1,906	$ 1,838
Capitalization (in millions):					
Common stock equity	$ 11,356	$ 10,719	$ 10,421	$ 9,591	$ 9,273
Preferred and preference stock	266	266	266	266	266
Long-term debt[(a)]	10,225	9,616	8,563	8,571	7,928
Total (excluding amounts due within one year)	$ 21,847	$ 20,601	$ 19,250	$ 18,428	$ 17,467
Capitalization Ratios (percent):					
Common stock equity	52.0	52.0	54.1	52.0	53.1
Preferred and preference stock	1.2	1.3	1.4	1.4	1.5
Long-term debt[(a)]	46.8	46.7	44.5	46.6	45.4
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	2,155,945	2,127,658	2,102,673	2,080,358	2,062,040
Commercial[(c)]	305,488	302,891	300,186	297,493	295,523
Industrial[(c)]	10,537	10,429	10,192	10,063	10,017
Other	9,585	9,261	9,003	8,623	7,724
Total	2,481,555	2,450,239	2,422,054	2,396,537	2,375,304
Employees (year-end)	7,527	7,989	7,909	7,886	8,094

(a) A reclassification of debt issuance costs from Total Assets to Long-term debt of $124 million, $62 million, and $67 million is reflected for years 2014, 2013, and 2012, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(b) A reclassification of deferred tax assets from Total Assets of $34 million, $68 million, and $117 million is reflected for years 2014, 2013, and 2012, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(c) A reclassification of customers from commercial to industrial is reflected for years 2012-2015 to be consistent with the rate structure approved by the Georgia PSC. The impact to operating revenues, kilowatt-hour sales, and average revenue per kilowatt-hour by class is not material.

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	2016	2015	2014	2013	2012
Operating Revenues (in millions):					
Residential	$3,318	$3,240	$3,350	$3,058	$2,986
Commercial	3,077	3,094	3,271	3,077	2,965
Industrial	1,291	1,305	1,525	1,391	1,322
Other	86	88	94	94	89
Total retail	7,772	7,727	8,240	7,620	7,362
Wholesale — non-affiliates	175	215	335	281	281
Wholesale — affiliates	42	20	42	20	20
Total revenues from sales of electricity	7,989	7,962	8,617	7,921	7,663
Other revenues	394	364	371	353	335
Total	$8,383	$8,326	$8,988	$8,274	$7,998
Kilowatt-Hour Sales (in millions):					
Residential	27,585	26,649	27,132	25,479	25,742
Commercial	32,932	32,719	32,426	31,984	32,270
Industrial	23,746	23,805	23,549	23,087	23,089
Other	610	632	633	630	641
Total retail	84,873	83,805	83,740	81,180	81,742
Wholesale — non-affiliates	3,415	3,501	4,323	3,029	2,934
Wholesale — affiliates	1,398	552	1,117	496	600
Total	89,686	87,858	89,180	84,705	85,276
Average Revenue Per Kilowatt-Hour (cents):					
Residential	12.03	12.16	12.35	12.00	11.60
Commercial	9.34	9.46	10.09	9.62	9.19
Industrial	5.44	5.48	6.48	6.03	5.73
Total retail	9.16	9.22	9.84	9.39	9.01
Wholesale	4.51	5.80	6.93	8.54	8.52
Total sales	8.91	9.06	9.66	9.35	8.99
Residential Average Annual Kilowatt-Hour Use Per Customer	12,864	12,582	12,969	12,293	12,509
Residential Average Annual Revenue Per Customer	$1,557	$1,529	$1,605	$1,475	$1,451
Plant Nameplate Capacity Ratings (year-end) (megawatts)	15,274	15,455	17,593	17,586	17,984
Maximum Peak-Hour Demand (megawatts):					
Winter	14,527	15,735	16,308	12,767	14,104
Summer	16,244	16,104	15,777	15,228	16,440
Annual Load Factor (percent)	61.9	61.9	61.2	63.5	59.1
Plant Availability (percent):					
Fossil-steam	87.4	85.6	86.3	87.1	90.3
Nuclear	95.6	94.1	90.8	91.8	94.1
Source of Energy Supply (percent):					
Coal	26.4	24.5	30.9	26.4	26.6
Nuclear	17.6	17.6	16.7	17.7	18.3
Hydro	1.1	1.6	1.3	2.0	0.7
Oil and gas	28.2	28.3	26.3	29.6	22.0
Purchased power —					

From non-affiliates	6.7	5.0	3.8	3.3	6.8
From affiliates	20.0	23.0	21.0	21.0	25.6
Total	100.0	100.0	100.0	100.0	100.0

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GULF POWER COMPANY
FINANCIAL SECTION

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Gulf Power Company 2016 Annual Report

The management of Gulf 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, 2016.

/s/ S. W. Connally, Jr.
S. W. Connally, Jr.
Chairman, President, and Chief Executive Officer
/s/ Xia Liu
Xia Liu
Vice President and Chief Financial Officer
February 21, 2017

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors of
Gulf Power Company

We have audited the accompanying balance sheets and statements of capitalization of Gulf Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2016 and 2015, 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, 2016. 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 II-342 to II-379) present fairly, in all material respects, the financial position of Gulf Power Company as of December 31, 2016 and 2015, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.
/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 21, 2017

DEFINITIONS

Term	Meaning
AFUDC	Allowance for funds used during construction
Alabama Power	Alabama Power Company
ARO	Asset retirement obligation
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
CCR	Coal combustion residuals
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
EPA	U.S. Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	U.S. generally accepted accounting principles
Georgia Power	Georgia Power Company
IRS	Internal Revenue Service
ITC	Investment tax credit
KWH	Kilowatt-hour
Mississippi Power	Mississippi Power Company
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MW	Megawatt
OCI	Other comprehensive income
power pool	The operating arrangement whereby the integrated generating resources of the traditional electric operating companies and Southern Power (excluding subsidiaries) are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power purchase agreement
PSC	Public Service Commission
ROE	Return on equity
S&P	S&P Global Ratings, a division of S&P Global Inc.
scrubber	Flue gas desulfurization system
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	U.S. Securities and Exchange Commission
Southern Company	The Southern Company
Southern Company Gas	Southern Company Gas (formerly known as AGL Resources Inc.) and its subsidiaries
Southern Company system	Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), Southern Electric Generating Company, Southern Nuclear, SCS, Southern LINC, PowerSecure, Inc. (as of May 9, 2016), and other subsidiaries
Southern LINC	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
traditional electric operating companies	Alabama Power, Georgia Power, Gulf Power Company, and Mississippi Power

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Gulf Power Company 2016 Annual Report
OVERVIEW
Business Activities
Gulf Power Company (the Company) operates as a vertically integrated utility providing electric service to retail customers within its traditional service territory located in northwest Florida and to wholesale customers in the Southeast.
Many factors affect the opportunities, challenges, and risks of the Company's business of providing electric service. 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, stringent environmental standards, reliability, restoration following major storms, fuel, and capital expenditures. 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. Through 2015, long-term non-affiliate capacity sales from the Company's ownership of Plant Scherer Unit 3 (205 MWs) provided the majority of the Company's wholesale earnings. Contract expirations at the end of 2015 and the end of May 2016 related to Plant Scherer Unit 3 wholesale sales had a material negative impact on the Company's earnings in 2016. Remaining contract sales from Plant Scherer Unit 3 cover approximately 24% of the Company's ownership of the unit through 2019.
In 2013, the Florida PSC approved the settlement agreement (2013 Rate Case Settlement Agreement) among the Company and all of the intervenors to the Company's retail base rate case. Under the terms of the 2013 Rate Case Settlement Agreement, the Company (1) increased base rates approximately $35 million and $20 million annually effective January 2014 and 2015, respectively; (2) continued its authorized retail ROE midpoint (10.25%) and range (9.25% – 11.25%); (3) may reduce depreciation expense and record a regulatory asset that will be included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million between January 2014 and June 2017, of which $28.5 million had been recorded as of December 31, 2016; and (4) accrued a return similar to AFUDC on certain transmission system upgrades placed into service after January 2014 through January 1, 2017.
On October 12, 2016, the Company filed a petition (2016 Rate Case) with the Florida PSC requesting an annual increase in retail rates and charges of $106.8 million based on the projected test year of January 1, 2017 through December 31, 2017 and a retail ROE of 11% compared to the current retail ROE of 10.25%. The requested increase includes recovery of the portion of Plant Scherer Unit 3 that has been rededicated to serving retail customers following the contract expirations discussed above. If retail recovery of Plant Scherer Unit 3 is not approved by the Florida PSC in the 2016 Rate Case, the Company may consider an asset sale. The current book value of the Company's ownership of Plant Scherer Unit 3 could exceed market value which could result in a material loss. The Florida PSC is expected to make a decision on the 2016 Rate Case in the second quarter 2017. The Company has requested that the increase in base rates, if approved by the Florida PSC, become effective in July 2017.
On November 2, 2016, the Florida PSC approved the Company's 2017 annual cost recovery clause factors. The fuel and environmental factors include certain costs associated with the ongoing ownership and operation of Plant Scherer Unit 3. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Cost Recovery Clauses" herein for additional information.
The Company continues to focus on several key performance indicators including, but not limited to, customer satisfaction, plant availability, system reliability, and net income after dividends on 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.
See RESULTS OF OPERATIONS herein for information on the Company's financial performance.
Earnings
The Company's 2016 net income after dividends on preference stock was $131 million, representing a $17 million, or 11.5%, decrease over the previous year. The decrease was primarily due to lower wholesale revenues and higher

depreciation, partially offset by higher retail revenues and lower operations and maintenance expenses as compared to the corresponding period in 2015.

In 2015, the net income after dividends on preference stock was $148 million, representing an $8 million, or 5.7%, increase over the previous year. The increase was primarily due to an increase in retail base revenues effective January 1, 2015 and a reduction in depreciation, both as authorized in the 2013 Rate Case Settlement Agreement, partially offset by higher operations and maintenance expenses as compared to the corresponding period in 2014.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Gulf Power Company 2016 Annual Report

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year	
	2016	2016	2015
	(in millions)		
Operating revenues	$1,485	$ 2	$ (107)
Fuel	432	(13)	(160)
Purchased power	142	7	28
Other operations and maintenance	336	(18)	13
Depreciation and amortization	172	31	(4)
Taxes other than income taxes	120	2	7
Total operating expenses	1,202	9	(116)
Operating income	283	(7)	9
Total other income and (expense)	(52)	(11)	3
Income taxes	91	(1)	4
Net income	140	(17)	8
Dividends on preference stock	9	—	—
Net income after dividends on preference stock	$131	$ (17)	$ 8

Operating Revenues

Operating revenues for 2016 were $1.49 billion, reflecting an increase of $2 million from 2015. Details of operating revenues were as follows:

	Amount	
	2016	2015
	(in millions)	
Retail — prior year	$1,249	$1,267
Estimated change resulting from –		
Rates and pricing	30	22
Sales growth	—	—
Weather	1	3
Fuel and other cost recovery	1	(43)
Retail — current year	1,281	1,249
Wholesale revenues –		
Non-affiliates	61	107
Affiliates	75	58
Total wholesale revenues	136	165
Other operating revenues	68	69
Total operating revenues	$1,485	$1,483
Percent change	N/M	(6.7)%

N/M - Not meaningful

In 2016, retail revenues increased $32 million, or 2.6%, when compared to 2015 primarily as a result of an increase in the Company's environmental cost recovery clause revenues, partially offset by a decrease in the energy conservation clause revenues. In 2015, retail revenues decreased $18 million, or 1.4%, when compared to 2014 primarily as a result of lower fuel cost recovery revenues partially offset by higher revenues associated with purchased power capacity costs and higher revenues resulting from an increase in retail base rates, as authorized in the 2013 Rate Case Settlement Agreement, as well as an increase in

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Gulf Power Company 2016 Annual Report

the environmental and energy conservation cost recovery clause rates, both effective in January 2015. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth and weather.

In 2016, revenues associated with changes in rates and pricing increased primarily due to an increase in the environmental cost recovery clause as a result of additional rate base investment related to environmental compliance equipment placed in service at the end of 2015 as well as portions of the Company's ownership in Plant Scherer Unit 3 that were rededicated to retail service in 2016. In 2015, revenues associated with changes in rates and pricing included higher revenues due to increases in retail base rates and the Company's environmental and energy conservation cost recovery clauses. Annually, the Company petitions the Florida PSC for recovery of projected environmental and energy conservation costs, including any true-up amount from prior periods, and approved rates are implemented each January. The recovery provisions include related expenses and a return on average net investment.

Fuel and other cost recovery provisions include fuel expenses, the energy component of purchased power costs, purchased power capacity costs, and the difference between projected and actual costs and revenues related to energy conservation and environmental compliance. Annually, the Company petitions the Florida PSC for recovery of projected fuel and purchased power costs, including any true-up amount from prior periods, and approved rates are implemented each January. The recovery provisions generally equal the related expenses and have no material effect on earnings.

See Note 1 to the financial statements under "Revenues" and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information regarding the Company's retail base rate case and cost recovery clauses, including the Company's fuel cost recovery, purchased power capacity recovery, environmental cost recovery, and energy conservation cost recovery clauses.

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

	2016	2015	2014
	(in millions)		
Capacity and other	$30	$67	$65
Energy	31	40	64
Total non-affiliated	$61	$107	$129

Wholesale revenues from sales to non-affiliates consist of long-term sales agreements to other utilities in Florida and Georgia and short-term opportunity sales. Capacity revenues from long-term sales agreements represent the greatest contribution to net income. The energy is generally sold at variable cost. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost of energy. Wholesale energy 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 electric service territory, and the availability of the Southern Company system's generation. See FUTURE EARNINGS POTENTIAL – "General" for additional information regarding the expiration of long-term sales agreements for Plant Scherer Unit 3, which will materially impact future wholesale earnings.

In 2016, wholesale revenues from sales to non-affiliates decreased $46 million, or 43.0%, as compared to the prior year primarily due to a 55.3% decrease in capacity revenues resulting from the expiration of Plant Scherer Unit 3 long-term sales agreements at the end of 2015 and the end of May 2016. In 2015, wholesale revenues from sales to non-affiliates decreased $22 million, or 17.1%, as compared to the prior year primarily due to a 37.7% decrease in KWH sales resulting from lower sales under the Plant Scherer Unit 3 long-term sales agreements due to a planned outage and lower natural gas prices that led to increased self-generation from customer-owned units.

Wholesale revenues from sales to affiliated companies will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the FERC. These transactions do not have a significant impact on earnings since the revenue related to these energy sales generally offsets the cost of energy sold. In 2016, wholesale revenues from sales to affiliates increased $17 million, or 29.3%, as compared to the prior year primarily due to a 46.1% increase in KWH sales to affiliates due to lower planned unit outages for the Company's generation resources and a 7.9% increase in the price of energy sold to affiliates due to more sales during peak load hours. In 2015, wholesale revenues from sales to affiliates decreased $72 million, or 55.4%, as compared to the prior year primarily due to a 23.5% decrease in the price of energy sold to affiliates due to lower power pool interchange rates resulting from lower natural gas prices and a 42.0% decrease in KWH sales that resulted from the availability of lower-cost generation alternatives.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Gulf Power Company 2016 Annual Report

In 2016, other operating revenues decreased by an immaterial amount compared to 2015. In 2015, other operating revenues increased $5 million, or 7.8%, as compared to the prior year primarily due to a $2 million increase in franchise fees and a $2 million increase in revenues from other energy services. Franchise fees have no impact on net income. Revenues from other energy services did not have a material effect on net income since they were generally offset by associated expenses.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2016 and the percent change from the prior year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2016	2016	2015	2016	2015
	(in millions)				
Residential	5,358	(0.1)%	— %	(0.2)%	(1.0)%
Commercial	3,869	(0.7)	1.6	(1.5)	0.3
Industrial	1,830	1.8	(2.8)	1.8	(2.8)
Other	25	(0.8)	(0.1)	(0.8)	(0.1)
Total retail	11,082	—	0.1	(0.3)%	(0.8)%
Wholesale					
Non-affiliates	751	(27.8)	(37.7)		
Affiliates	2,784	46.1	(42.0)		
Total wholesale	3,535	20.0	(40.5)		
Total energy sales	14,617	4.2 %	(12.5)%		

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.

Residential KWH sales decreased in 2016 compared to 2015 due to declining use per customer primarily resulting from energy efficiency improvements, partially offset by customer growth and warmer weather during the third quarter. Residential KWH sales increased minimally in 2015 compared to 2014 due to customer growth and warmer weather in the second and third quarters of 2015, mostly offset by a decline in use per customer, primarily resulting from efficiency improvements.

Commercial KWH sales decreased in 2016 compared to 2015 due to declining use per customer, primarily resulting from energy efficiency improvements, partially offset by customer growth and warmer weather during the third quarter. Commercial KWH sales increased in 2015 compared to 2014 due to customer growth and warmer weather in the second and third quarters of 2015, partially offset by a decline in use per customer, primarily resulting from efficiency improvements.

Industrial KWH sales increased in 2016 compared to 2015 primarily due to decreased customer co-generation, partially offset by changes in customers' operations. Industrial KWH sales decreased in 2015 compared to 2014 primarily due to increased customer co-generation as a result of lower natural gas prices, partially offset by increases due to changes in customers' operations.

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

Fuel and Purchased Power Expenses

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

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Gulf Power Company 2016 Annual Report

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

	2016	2015	2014
Total generation (in millions of KWHs)	8,259	8,629	11,109
Total purchased power (in millions of KWHs)	6,973	5,976	5,547
Sources of generation (percent) –			
Coal	57	57	67
Gas	43	43	33
Cost of fuel, generated (in cents per net KWH) –			
Coal	3.68	3.88	4.03
Gas	4.17	4.22	3.93
Average cost of fuel, generated (in cents per net KWH)	3.89	4.03	3.99
Average cost of purchased power (in cents per net KWH)(*)	3.63	3.89	4.83

(*) Average cost of purchased power includes fuel purchased by the Company for tolling agreements where power is generated by the provider.

In 2016, total fuel and purchased power expenses were $574 million, a decrease of $6 million, or 1.0%, from the prior year costs. The decrease was primarily the result of a $30 million decrease due to a lower average cost of fuel and purchased power, largely offset by a $24 million increase due to a higher volume of KWHs generated and purchased.

In 2015, total fuel and purchased power expenses were $580 million, a decrease of $132 million, or 18.5%, from the prior year costs. The decrease was primarily the result of a $79 million decrease due to a lower volume of KWHs generated and purchased and a $53 million decrease due to a lower average cost of fuel and purchased power.

Fuel and purchased power transactions do not have a significant impact on earnings since energy and capacity expenses are generally offset by energy and capacity revenues through the Company's fuel and purchased power capacity cost recovery clauses and long-term wholesale contracts. See Note 3 to the financial statements under "Retail Regulatory Matters – Cost Recovery Clauses – Retail Fuel Cost Recovery" and " – Purchased Power Capacity Recovery" for additional information.

Fuel

Fuel expense was $432 million in 2016, a decrease of $13 million, or 2.9%, from the prior year costs. The decrease was primarily due to a 3.5% decrease in the average cost of fuel due to lower coal and natural gas prices and a 4.3% lower volume of KWHs generated due to an increase in KWHs purchased from lower-cost gas-fired PPA resources. In 2015, fuel expense was $445 million, a decrease of $160 million, or 26.4%, from the prior year costs. The decrease was primarily due to a 22.3% lower volume of KWHs generated due to the availability of lower-cost generation alternatives, partially offset by a 1.0% increase in the average cost of fuel due to higher natural gas prices per KWH generated.

Purchased Power – Non-Affiliates

Purchased power expense from non-affiliates was $126 million in 2016, an increase of $26 million, or 26.0%, from the prior year. The increase was primarily due to a 41.2% increase in the volume of KWHs purchased due to an increase in energy purchased from gas-fired PPA resources, partially offset by a 14.9% decrease in the average cost per KWH purchased, both due to lower energy costs from gas-fired resources. In 2015, purchased power expense from non-affiliates was $100 million, an increase of $18 million, or 22.0%, from the prior year. The increase was primarily due to a $26 million increase in capacity costs associated with a scheduled price increase for an existing PPA, partially offset by the expiration of another PPA, an 11.9% decrease in the average cost per KWH purchased due to lower market prices for fuel, and a 7.8% decrease in the volume of KWHs purchased due to the availability of lower-cost generation alternatives.

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 electric service territory, and the availability of the Southern Company system's generation.

Purchased Power – Affiliates

Purchased power expense from affiliates was $16 million in 2016, a decrease of $19 million, or 54.3%, from the prior year. The decrease was primarily due to a 53.9% decrease in the volume of KWHs purchased primarily due to increased supply from the Company's fossil and wind resources, partially offset by a 0.4% increase in the average cost per KWH purchased from power pool resources. In 2015, purchased power expense from affiliates was $35 million, an increase of $10 million, or 40.0%, from the prior year. The increase was primarily due to a 108.9% increase in the volume of KWHs purchased primarily due to the availability of lower-cost generation alternatives available from the power pool, partially offset by a 34.2% decrease in the average cost per KWH purchased due to lower power pool interchange rates.

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

Other Operations and Maintenance Expenses

In 2016, other operations and maintenance expenses decreased $18 million, or 5.1%, compared to the prior year primarily due to decreases of $7 million in marketing incentive programs and $6 million in routine and planned maintenance expenses at generation facilities. Also contributing to the decrease was $4 million in rate case expense amortization recorded in 2015 and a $3 million reduction in employee compensation and benefits expenses including pension costs. In 2015, other operations and maintenance expenses increased $13 million, or 3.8%, compared to the prior year primarily due to increases of $6 million in employee compensation and benefits expenses including pension costs, $3 million in rate case expense amortization, and $2 million in energy service contracts.

Expenses from marketing incentive programs and energy services did not have a significant impact on earnings since they were generally offset by associated revenues. Rate case expenses were amortized as authorized in the 2013 Rate Case Settlement Agreement. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Cost Recovery Clauses" herein and Note 2 to the financial statements for additional information related to rate case expenses and pension costs, respectively.

Depreciation and Amortization

Depreciation and amortization increased $31 million, or 22.0%, in 2016 compared to the prior year. The increase was primarily due to a reduction in depreciation of $20.1 million recorded in 2015, as authorized in the 2013 Rate Case Settlement Agreement, and an increase of $9 million primarily attributable to property additions to utility plant. In 2015, depreciation and amortization decreased $4 million, or 2.8%, compared to the prior year. As authorized in the 2013 Rate Case Settlement Agreement, the Company recorded $11.7 million more of a reduction in depreciation in 2015 than in 2014. This decrease was partially offset by an increase of $8 million primarily attributable to property additions at transmission and distribution facilities. See Note 3 to the financial statements under "Retail Regulatory Matters – Retail Base Rate Cases" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $2 million, or 1.7%, in 2016 compared to the prior year primarily due to increases of $2 million in property taxes. In 2015, taxes other than income taxes increased $7 million, or 6.3%, compared to the prior year primarily due to increases of $3 million in property taxes, $2 million in franchise fees, and $2 million in gross receipts taxes. Gross receipts taxes and franchise fees are based on billed revenues and have no impact on net income. These taxes are collected from customers and remitted to governmental agencies.

Total Other Income and (Expense)

In 2016, total other income and (expense) decreased $11 million, or 26.8%, compared to the prior year primarily due to a decrease of $13 million in AFUDC equity related to environmental control projects at generating facilities and transmission projects placed in service in 2015, partially offset by a $2 million decrease in interest expense, net of amounts capitalized, primarily due to the redemption of debt. In 2015, total other income and (expense) increased $3 million, or 6.8%, primarily due to $6 million in deferred returns on transmission projects, which reduced interest expense and were recorded as a regulatory asset, as authorized in the 2013 Rate Case Settlement Agreement. This decrease was partially offset by a $2 million net increase in interest expense related to long-term debt resulting from the issuance of senior notes in 2014. See Note 1 to the financial statements under "Allowance for Funds Used During Construction" for additional information.

Effects of Inflation

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

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electric service to retail customers within its traditional service territory located in northwest Florida and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Florida 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 – Utility Regulation" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs and limited projected demand growth over the next several years, and the outcome of the 2016 Rate Case. Future earnings will be driven primarily by customer growth. Earnings will also depend upon maintaining and growing sales, considering, among other things, the adoption and/or penetration rates of increasingly energy-efficient technologies due to changes in the minimum allowable equipment efficiencies along with the continuation of changes in customer behavior. Earnings are subject to a variety of other factors. These factors include weather, competition, 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 primarily 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.

Current proposals related to potential tax reform legislation are primarily focused on reducing the corporate income tax rate, allowing 100% of capital expenditures to be deducted, and eliminating the interest deduction. The ultimate impact of any tax reform proposals is dependent on the final form of any legislation enacted and the related transition rules and cannot be determined at this time, but could have a material impact on the Company's financial statements.

Through 2015, long-term non-affiliate capacity sales from the Company's ownership of Plant Scherer Unit 3 provided the majority of the Company's wholesale earnings. Contract expirations at the end of 2015 and the end of May 2016 related to Plant Scherer Unit 3 wholesale sales had a material negative impact on the Company's earnings in 2016. Remaining contract sales from Plant Scherer Unit 3 cover approximately 24% of the Company's ownership of the unit through 2019. The Company has requested recovery through retail rates for the portion of Plant Scherer Unit 3 that has been rededicated to serving retail customers. Therefore, the retail recoverability of these costs will be decided in the 2016 Rate Case. If retail recovery of Plant Scherer Unit 3 is not approved by the Florida PSC in the 2016 Rate Case, the Company may consider an asset sale. The current book value of the Company's ownership of Plant Scherer Unit 3 could exceed market value which could result in a material loss. See Note 3 to the financial statements under "Retail Regulatory Matters – Retail Base Rate Cases" for additional information.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in retail rates or through long-term wholesale agreements on a timely basis or through market-based contracts. The State of Florida has statutory provisions that allow a utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. The Company's current long-term wholesale agreements contain provisions that permit charging the customer with costs incurred as a result of changes in environmental laws and regulations. The full impact of any such legislative or regulatory changes cannot be determined at this time. 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. Further, higher costs that are recovered through regulated rates or long-term wholesale agreements could contribute to reduced demand for electricity as well as impact the cost competitiveness of wholesale capacity, which could negatively affect results of operations, cash flows, and financial condition. See "Other Matters" herein and Note 3 to the financial statements under "Environmental Matters" and "Retail Regulatory Matters – Cost Recovery Clauses – Environmental Cost Recovery" for additional information, including a discussion on the State of Florida's statutory provisions on environmental cost recovery.

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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 2016, the Company had invested approximately $1.9 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $28 million, $116 million, and $227 million for 2016, 2015, and 2014, respectively. The Company expects that capital expenditures to comply with environmental statutes and regulations will total approximately $245 million from 2017 through 2021, with annual totals of approximately $33 million, $52 million, $57 million, $55 million, and $48 million for 2017, 2018, 2019, 2020, and 2021, respectively. These estimated expenditures do not include any potential capital expenditures that may arise from the EPA's final rules and guidelines or future state plans that would limit CO_2 emissions from existing, new, modified, or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" herein for additional information. The Company also anticipates costs associated with ash pond closure and ground water monitoring under the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule) and the closure of an ash pond at Plant Scholz, which are reflected in the Company's ARO liabilities. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 1 to the financial statements under "Asset Retirement Obligations and Other Cost of Removal" 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 time periods over which compliance with regulations is required; individual state implementation of regulations, as applicable; the outcome of any legal challenges to the environmental rules; any additional rulemaking activities in response to legal challenges and court decisions; the cost, availability, and existing inventory of emissions allowances; the impact of future changes in generation and emissions-related technology; the Company's fuel mix; and environmental remediation requirements. 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.

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.

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 implementation strategy for the MATS rule included emission controls, retirements, and fuel conversions at affected units. All of the Company's units that are subject to the MATS rule completed the measures necessary to achieve

compliance with this rule or were retired prior to or during 2016.
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. In October 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 were required to recommend area designations by October 2016, and no areas within the Company's service territory were proposed for designation as nonattainment.
The EPA regulates fine particulate matter concentrations through an annual and 24-hour average NAAQS, based on standards promulgated in 1997, 2006, and 2012. All areas in which the Company's generating units are located have been determined by the EPA to be in attainment with those standards.

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In 2010, the EPA revised the NAAQS for sulfur dioxide (SO_2), establishing a new one-hour standard. No areas within the Company's service territory have been designated as nonattainment under this standard. However, in 2015, the EPA finalized a data requirements rule to support final EPA designation decisions for all remaining areas under the SO_2 standard, which could result in nonattainment designations for areas within the Company's service territory. Nonattainment designations could require additional reductions in SO_2 emissions and increased compliance and operational costs.

On July 6, 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide (NO_x) emissions from power plants in two phases – Phase 1 in 2015 and Phase 2 in 2017. On October 26, 2016, the EPA published a final rule that updates the CSAPR ozone-season NO_x program, beginning in 2017, and establishes more stringent ozone-season emissions budgets in Mississippi and removes Florida from the program. The State of Georgia's emission budget was not affected by the revisions, but interstate emissions trading is restricted unless the state decides to voluntarily adopt a significantly reduced budget. Georgia is also in the CSAPR annual SO_2 and NO_x programs.

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. On December 14, 2016, the EPA finalized revisions to the regional haze regulations. These regulations establish a deadline of July 31, 2021 for states to submit revised State Implementation Plans (SIP) to the EPA demonstrating reasonable progress toward the statutory goal of achieving natural background conditions by 2064. State implementation of the reasonable progress requirements defined in this final rule could require further reductions in SO_2 or NO_x emissions.

In June 2015, the EPA published a final rule requiring certain states (including Florida, Georgia, and Mississippi) 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), and proposed SIP revisions have been submitted by the affected states where the Company's generating units are located.

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. 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. The ultimate impact of the eight-hour ozone and SO_2 NAAQS, CSAPR, regional haze regulations, and SSM rule will depend on various factors, such as implementation, adoption, or other action at the state level, and the outcome of pending and/or future legal challenges, and cannot be determined at this time.

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 2014. The effect of this final rule will depend on the results of additional studies that are currently underway and implementation of the rule by regulators based on site-specific factors. National Pollutant Discharge Elimination System (NPDES) permits issued after July 14, 2018 must include conditions to implement and ensure compliance with the standards and protective measures required by the rule.

In November 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 NPDES 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.
In 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 in August 2015 but, in October 2015, the U.S. Court of Appeals for the Sixth Circuit issued an order staying implementation of the final rule. The case is held in abeyance pending review by the U.S. Supreme Court of challenges to the U.S. Court of Appeals for the Sixth Circuit's jurisdiction in the case.

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In addition, numeric nutrient water quality standards promulgated by the State of Florida to limit the amount of nitrogen and phosphorous allowed in state waters are in effect for the State's streams and estuaries. The impact of these standards will depend on further regulatory action in connection with their site-specific implementation through the State of Florida's National Pollutant Discharge Elimination System permitting program and Total Maximum Daily Load restoration program 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 and decisions on infrastructure expansion and improvements. 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. The ultimate impact of these final rules will depend on various factors, such as pending and/or future legal challenges, compliance dates, and implementation of the rules, and cannot be determined at this time.

Coal Combustion Residuals

The Company currently manages CCR at onsite storage units consisting of landfills and surface impoundments (CCR Units) at three electric generating plants in Florida and is a co-owner of units at generating plants located in Mississippi and Georgia operated by Mississippi Power and Georgia Power, respectively. In addition to on-site storage, the Company sells a portion of its CCR to third parties for beneficial reuse. Individual states regulate CCR and the States of Florida, Mississippi, and Georgia each have their own regulatory requirements. The Company has an inspection program in place to assist in maintaining the integrity of its coal ash surface impoundments.

The CCR Rule became effective in October 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. On December 16, 2016, President Obama signed the Water Infrastructure Improvements for the Nation Act (WIIN Act). The WIIN Act allows states to establish permit programs for implementing the CCR Rule, if the EPA approves the program, and allows for federal permits and EPA enforcement where a state permitting program does not exist.

Based on current cost estimates for closure and monitoring of ash ponds pursuant to the CCR Rule, and the closure of an ash pond at Plant Scholz, the Company has recorded AROs. 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 with respect to compliance activities, the Company expects to continue to periodically update these estimates. The Company has posted closure and post-closure care plans to its public website as required by the CCR Rule; however, the ultimate impact of the CCR Rule will depend on the results of initial and ongoing minimum criteria assessments and the implementation of state or federal permit programs. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. The estimated costs associated with closure of the ash ponds at Plant Scholz and Plant Smith for 2017 have been approved for recovery through the environmental cost recovery clause. 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, 2016.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company 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 affected sites. Included in this amount are costs associated with remediation of the Company's substation sites. These projects have been approved by the Florida PSC for recovery through the environmental cost recovery clause; therefore, these liabilities have no impact to the Company's net income. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Global Climate Issues

In October 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

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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 review with the courts. The stay will remain in effect through the resolution of the litigation, including any review by 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 and decisions on infrastructure expansion and improvements. 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 outcome of pending legal challenges, including legal challenges filed by the traditional electric operating companies, and any individual state implementation of the EPA's final guidelines in the event the rule is upheld and implemented.

In December 2015, parties to the United Nations Framework Convention on Climate Change – including the United States – adopted 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 tracking progress toward the goals every five years. The ultimate impact of this agreement depends on its implementation by participating countries and cannot be determined at this time.

The EPA's greenhouse gas reporting rule requires annual reporting of greenhouse gas emissions expressed in terms of metric tons of CO_2 equivalent emissions for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2015 greenhouse gas emissions were approximately 9 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2016 greenhouse gas emissions on the same basis is approximately 8 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 electric operating companies (including the Company) and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In April 2015, the FERC issued an order finding that the traditional electric 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 electric operating companies and in some adjacent areas. The FERC directed the traditional electric 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 electric operating companies (including the Company) and Southern Power filed a request for rehearing in May 2015 and in June 2015 filed their response with the FERC.

On December 9, 2016, the traditional electric operating companies (including the Company) and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' (including the Company's) and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies (including the Company) and in some adjacent areas. The traditional electric operating companies (including the Company) and Southern Power expect to make a compliance filing within 30 days accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.

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

Retail Regulatory Matters

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates. See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.

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Retail Base Rate Cases
In 2013, the Florida PSC approved the 2013 Rate Case Settlement Agreement among the Company and all of the intervenors to the Company's retail base rate case. Under the terms of the 2013 Rate Case Settlement Agreement, the Company (1) increased base rates approximately $35 million and $20 million annually effective January 2014 and 2015, respectively; (2) continued its authorized retail ROE midpoint (10.25%) and range (9.25% – 11.25%); (3) may reduce depreciation expense and record a regulatory asset that will be included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million between January 2014 and June 2017, of which $28.5 million had been recorded as of December 31, 2016; and (4) accrued a return similar to AFUDC on certain transmission system upgrades placed into service after January 2014 through January 1, 2017.
The 2013 Rate Case Settlement Agreement also provides that the Company may reduce depreciation and record a regulatory asset that will be included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million from January 2014 through June 2017. In any given month, such depreciation reduction may not exceed the amount necessary for the retail ROE, as reported to the Florida PSC monthly, to reach the midpoint of the authorized retail ROE range then in effect. Recovery of the regulatory asset will occur over a period to be determined by the Florida PSC in the Company's 2016 Rate Case. For 2014 and 2015, the Company recognized reductions in depreciation expense of $8.4 million and $20.1 million, respectively. No net reduction in depreciation was recorded in 2016.
On October 12, 2016, the Company filed the 2016 Rate Case with the Florida PSC requesting an annual increase in retail rates and charges of $106.8 million based on the projected test year of January 1, 2017 through December 31, 2017 and a retail ROE of 11% compared to the current retail ROE of 10.25%. The requested increase includes recovery of the portion of Plant Scherer Unit 3 that has been rededicated to serving retail customers following the contract expirations discussed previously. If retail recovery of Plant Scherer Unit 3 is not approved by the Florida PSC in the 2016 Rate Case, the Company may consider an asset sale. The current book value of the Company's ownership of Plant Scherer Unit 3 could exceed market value which could result in a material loss. The Florida PSC is expected to make a decision on the 2016 Rate Case in the second quarter 2017. The Company has requested that the increase in base rates, if approved by the Florida PSC, become effective in July 2017. The ultimate outcome of this matter cannot be determined at this time.
See Note 3 to the financial statements under "Retail Regulatory Matters – Retail Base Rate Cases" for additional information.
Cost Recovery Clauses
On November 2, 2016, the Florida PSC approved the Company's 2017 annual cost recovery clause rates for its fuel, purchased power capacity, environmental, and energy conservation cost recovery clauses. The net effect of the approved changes is a decrease of approximately $41 million in annual revenues effective in January 2017. In general, the decreased revenues will not have a significant impact on net income since most of the revenues will be offset by lower expenses. However, certain costs associated with the ongoing ownership and operation of Plant Scherer Unit 3 were included in the environmental cost recovery clause rate, which increased annual revenues by approximately $12 million in 2016 and is expected to increase revenues by an incremental $2 million for a total of approximately $14 million in 2017. The final disposition of these costs, and the related impact on rates, is subject to the Florida PSC's ultimate ruling on whether costs associated with Plant Scherer Unit 3 are recoverable from retail customers, which is expected to be decided in the 2016 Rate Case as discussed previously. The ultimate outcome of this matter cannot be determined at this time. See Note 3 to the financial statements under "Retail Regulatory Matters – Retail Base Rate Cases" for additional information.
Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor for fuel and purchased power will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. The recovery provisions for environmental compliance and energy conservation include related expenses and a

return on net average investment. See Note 1 to the financial statements under "Revenues" for additional information.
Renewables
In April 2015, the Florida PSC approved three energy purchase agreements totaling 120 MWs of utility-scale solar generation located at three military installations in northwest Florida. Purchases under these solar agreements are expected to begin by the summer of 2017.
The Florida PSC issued a final approval order on the Company's Community Solar Pilot Program on April 15, 2016. The program will offer the Company's customers an opportunity to voluntarily contribute to the construction and operation of a solar photovoltaic facility with electric generating capacity of up to 1 MW through annual subscriptions. The energy generated from the solar facility is expected to provide power to all of the Company's customers.

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On November 29, 2016, the Florida PSC approved an energy purchase agreement for up to 94 MWs of additional wind generation in central Oklahoma. Purchases under this agreement will be for energy only and will be recovered through the Company's fuel cost recovery clause.

Income Tax Matters

Bonus Depreciation

In December 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. Bonus depreciation was extended for qualified property placed in service through 2020. The PATH Act allows for 50% bonus depreciation for 2015 through 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 bonus depreciation included in the PATH Act is expected to result in approximately $20 million of positive cash flows for the 2016 tax year and approximately $26 million for the 2017 tax year. See Note 5 to the financial statements for additional information.

Other Matters

As a result of the cost to comply with environmental regulations imposed by the EPA, the Company retired its coal-fired generation at Plant Smith Units 1 and 2 (357 MWs) on March 31, 2016. The Company filed a petition with the Florida PSC requesting permission to recover the remaining net book value of Plant Smith Units 1 and 2 and the remaining materials and supplies associated with these units as of the retirement date. On August 29, 2016, the Florida PSC approved the Company's request to reclassify these costs, totaling approximately $63 million, to a regulatory asset for recovery over a period to be decided in the 2016 Rate Case. The ultimate outcome of this matter cannot be determined at this time.

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.

Utility Regulation

The Company is subject to retail regulation by the Florida PSC. The Florida PSC sets the rates the Company is permitted to charge customers based on allowable costs. The Company is also subject to cost-based regulation by the FERC with respect to wholesale transmission rates. 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 other 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.

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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 Company's facilities that are subject to the CCR Rule and to the closure of an ash pond at Plant Scholz. In addition, the Company has retirement obligations related to combustion turbines at its Pea Ridge facility, various landfill sites, a barge unloading dock, asbestos removal, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, certain wireless communication towers, and certain structures authorized by the U.S. Army Corps of Engineers. 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 recorded new AROs in 2015 for facilities that are subject to the CCR Rule as discussed above and for the closure of an ash pond at Plant Scholz. 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 for those facilities impacted by 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 with respect to compliance activities, 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. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Coal Combustion Residuals" herein for additional information.

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" 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 adopted

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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 decreased by approximately $4 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 $2 million or less change in total annual benefit expense and a $21 million or less change in projected obligations.

See Note 2 to the financial statements for additional information regarding pension and other postretirement benefits.

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

In 2014, the FASB issued ASC 606, Revenue from Contracts with Customers, replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the guidance is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

While the Company expects most of its revenue to be included in the scope of ASC 606, it has not fully completed its evaluation of such arrangements. The majority of the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term. For such arrangements, the Company generally expects that the revenue from contracts with these customers will continue to be equivalent to the electricity supplied and billed in that period (including unbilled revenues) and the adoption of ASC 606 will not result in a significant shift in the timing of revenue recognition for such sales.

The Company's ongoing evaluation of other revenue streams and related contracts includes longer term contractual commitments and unregulated sales to customers. Some revenue arrangements, such as certain PPAs and alternative revenue programs, are expected to be excluded from the scope of ASC 606 and therefore, be accounted for and presented separately from revenues under ASC 606 on the Company's financial statements. In addition, the power and utilities industry is currently addressing other specific industry issues, including the applicability of ASC 606 to contributions in aid of construction (CIAC). If final implementation guidance indicates CIAC will be accounted for under ASC 606 and offsetting regulatory treatment is not permitted, it could have a material impact on the Company's financial statements.

The new standard is effective for interim and annual reporting periods beginning after December 15, 2017. The Company must select a transition method to be applied either retrospectively to each prior reporting period presented or retrospectively with a cumulative effect adjustment to retained earnings at the date of initial adoption. As the ultimate impact of the new standard has not yet been determined, the Company has not elected its transition method.

On February 25, 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842) (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company is currently evaluating the new standard and has not yet determined its ultimate impact; however, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

On March 30, 2016, the FASB issued ASU No. 2016-09, Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting (ASU 2016-09). ASU 2016-09 changes the accounting for income taxes and the cash flow presentation for share-based payment award transactions effective for fiscal years beginning after December 15, 2016. The new guidance requires all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation to be recognized as income tax expense or benefit in the income statement. Previously, the Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities rather than net cash provided from financing activities on the statement of cash flows. The Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. The Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of the Company. See Notes 5, 8, and 11 to the financial statements for disclosures impacted by ASU 2016-09.

On October 24, 2016, the FASB issued ASU No. 2016-16, Income Taxes (Topic 740), Intra-Entity Transfers of Assets Other Than Inventory (ASU 2016-16). Current GAAP prohibits the recognition of current and deferred income taxes for an affiliate asset transfer until the asset has been sold to an outside party. ASU 2016-16 requires an entity to recognize the income tax consequences of an affiliate transfer of an asset other than inventory when the transfer occurs. ASU 2016-16 is effective for annual reporting periods beginning after December 15, 2017 and interim periods within those annual periods. The amendments will be applied on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. The Company is currently assessing the impact of the standard on its financial statements and has not yet determined its ultimate impact.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2016. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to maintain existing facilities, to comply with environmental regulations including adding environmental modifications to certain existing generating units, to expand and improve transmission and distribution facilities, 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 2017 through 2019, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt issuances in the capital markets, borrowings from financial institutions, and equity contributions from Southern Company. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as bank credit agreements 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 increased in value as of December 31, 2016 as compared to December 31, 2015. On December 19, 2016, the Company voluntarily contributed $48 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated during 2017. See Note 2 to the financial statements under "Pension Plans" for additional information.

Net cash provided from operating activities totaled $379 million in 2016, a decrease of $81 million from 2015, primarily due to decreases in cash flows related to clause recovery and a voluntary contribution to the qualified pension plan, partially offset by the timing of fossil fuel stock purchases. Net cash provided from operating activities totaled $460 million in 2015, an increase of $116 million from 2014, primarily due to increases in cash flows related to clause recovery and bonus depreciation. This increase was partially offset by decreases related to the timing of fossil fuel stock purchases and vendor payments.

Net cash used for investing activities totaled $180 million, $281 million, and $358 million for 2016, 2015, and 2014, respectively. The changes in cash used for investing activities were primarily related to gross property additions for environmental, distribution, steam generation, and transmission assets. Funds for the Company's property additions were provided by operating activities, capital contributions, and other financing activities.

Net cash used for financing activities totaled $217 million in 2016 primarily due to the redemptions of long-term debt and the payment of common stock dividends, partially offset by an increase in notes payable. Net cash used for financing activities totaled $144 million in 2015 primarily due to the payment of common stock dividends and redemptions of long-term debt, partially offset by an increase in notes payable and proceeds from the issuance of common stock to Southern Company. Net cash provided from financing activities totaled $31 million in 2014 primarily due to the issuance of long-term debt and common stock to Southern Company, partially offset by the payment of common stock dividends, the redemption of long-term debt, and a decrease to notes payable. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes in 2016 included a decrease of $206 million in long-term debt due to the early retirement and redemption at maturity of $235 million in senior notes and the reclassification of $85 million in senior notes to securities due within one year, an increase of $126 million in notes payable, and an increase of $85 million in other regulatory assets, deferred,

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primarily related to the retirement of Plant Smith Units 1 and 2 and CCR compliance costs. See Note 3 to the financial statements for additional information related to the retirement of Plant Smith Units 1 and 2.

The Company's ratio of common equity to total capitalization plus short-term debt, was 48.3% and 46.0% at December 31, 2016 and 2015, respectively. See Note 6 to the financial statements for additional information.

Sources of Capital

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

Security issuances are subject to annual regulatory approval by the Florida PSC pursuant to its rules and regulations. 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 (1933 Act). The amounts of securities authorized by the Florida PSC, as well as the amounts registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

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

The Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet scheduled maturities of long-term debt, as well as significant seasonal fluctuations in cash needs. The Company has substantial cash flow from operating activities and access to the capital markets and financial institutions to meet short-term liquidity needs, including its commercial paper program which is supported by bank credit facilities.

At December 31, 2016, the Company had approximately $56 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2016 were as follows:

Expires				Executable Term Loans		Expires Within One Year	
2017	2018	Total	Unused	One Year	Two Years	Term Out	No Term Out
(in millions)		(in millions)		(in millions)		(in millions)	
$85	$195	$280	$280	$45	$—	$25	$60

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. At December 31, 2016, the Company was 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.

Most of the unused credit arrangements with banks are allocated to provide liquidity support to the Company's pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2016 was approximately $82 million. In addition, at December 31, 2016, the Company had $86 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional electric operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each traditional electric operating company under these arrangements are several and there is no cross-affiliate credit support. Short-term borrowings are included in notes payable in the balance sheets.

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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, 2016					
Commercial paper	$ 168	1.1 %	$ 53	0.9 %	$ 168
Short-term bank debt	100	1.5 %	64	1.3 %	100
Total	$ 268	1.2 %	$ 117	1.1 %	
December 31, 2015					
Commercial paper	$ 142	0.7 %	$ 101	0.4 %	$ 175
Short-term bank debt	—	— %	10	0.7 %	40
Total	$ 142	0.7 %	$ 111	0.4 %	
December 31, 2014					
Commercial paper	$ 110	0.3 %	$ 85	0.2 %	$ 145

(*) Average and maximum amounts are based upon daily balances during the year.

The Company believes the need for working capital can be adequately met by utilizing the commercial paper program, lines of credit, short-term bank term loans, and operating cash flows.

Financing Activities

In May 2016, the Company redeemed $125 million aggregate principal amount of its Series 2011A 5.75% Senior Notes due June 1, 2051.

Also in May 2016, the Company entered into an 11-month floating rate bank loan bearing interest based on one-month LIBOR. This short-term loan was for $100 million aggregate principal amount and the proceeds were used to repay existing indebtedness and for working capital and other general corporate purposes.

In December 2016, the Company repaid at maturity $110 million aggregate principal amount of its Series M 5.30% Senior Notes due December 1, 2016.

Subsequent to December 31, 2016, the Company issued 1,750,000 shares of common stock to Southern Company and realized proceeds of $175 million. The proceeds were used for general corporate purposes, including the Company's continuous construction program.

In addition to any financings that may be necessary to meet capital requirements, contractual obligations, and storm recovery, 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

At December 31, 2016, the Company did not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

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

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The maximum potential collateral requirements under these contracts at December 31, 2016 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements (in millions)
At BBB- and/or Baa3	$ 192
Below BBB- and/or Baa3	$ 628

Included in these amounts are certain agreements that could require collateral in the event that Alabama Power or Georgia Power 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 January 10, 2017, S&P revised its consolidated credit rating outlook for Southern Company (including the Company) from negative to stable.

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 may enter into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company may enter into derivatives which are designated as hedges. The weighted average interest rate on $82 million of outstanding variable rate long-term debt that has not been hedged at January 1, 2017 was 0.79%. If the Company sustained a 100 basis point change in interest rates for all variable rate long-term debt, the change would not materially affect annualized interest expense at January 1, 2017. See Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements for additional information.

To mitigate residual risks relative to movements in fuel and electricity prices, the Company enters into financial hedge contracts for natural gas purchases and physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. The Company continues to manage a fuel-hedging program implemented per the guidelines of the Florida PSC and the actual cost of fuel is recovered through the retail fuel clause. The Florida PSC approved a stipulation and agreement that prospectively imposed a moratorium on the Company's fuel-hedging program in October 2016 through December 31, 2017. The Company had no material change in market risk exposure for the year ended December 31, 2016 when compared to the year ended December 31, 2015.

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, substantially all of which are composed of regulatory hedges, were as follows:

	2016 Changes	2015 Changes
	Fair Value (in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	$(100)	$(72)
Contracts realized or settled	49	47
Current period changes(*)	27	(75)

Contracts outstanding at the end of the period, assets (liabilities), net	$(24)	$(100)

(*) 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 were 51 million mmBtu and 82 million mmBtu as of December 31, 2016 and December 31, 2015, respectively.

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The weighted average swap contract cost above market prices was approximately $0.48 per mmBtu as of December 31, 2016 and $1.17 per mmBtu as of December 31, 2015. Natural gas settlements are recovered through the Company's fuel cost recovery clause.

At December 31, 2016 and 2015, 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 fuel cost recovery clause. 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 and the actual cost of fuel is recovered through the retail fuel clause. The moratorium imposed by the Florida PSC does not have an impact on the recovery of existing hedges entered into under the previously-approved hedging program.

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 of the fair value hierarchy. See Note 9 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, 2016 were as follows:

	Fair Value Measurements December 31, 2016			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
	(in millions)			
Level 1	$—	$—	$ —	$ —
Level 2	(24)	(8)	(16)	—
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$(24)	$(8)	$ (16)	$ —

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related 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 10 to the financial statements.

Through 2015, long-term non-affiliate capacity sales from the Company's ownership of Plant Scherer Unit 3 provided the majority of the Company's wholesale earnings. Contract expirations at the end of 2015 and the end of May 2016 related to Plant Scherer Unit 3 wholesale sales had a material negative impact on the Company's earnings in 2016. Remaining contract sales from Plant Scherer Unit 3 cover approximately 24% of the Company's ownership of the unit through 2019. The Company has requested recovery through retail rates for the portion of Plant Scherer Unit 3 that has been rededicated to serving retail customers. Therefore, the retail recoverability of these costs will be decided in the 2016 Rate Case. If retail recovery of Plant Scherer Unit 3 is not approved by the Florida PSC in the 2016 Rate Case, the Company may consider an asset sale. The current book value of the Company's ownership of Plant Scherer Unit 3 could exceed market value which could result in a material loss. See Note 3 to the financial statements under "Retail Regulatory Matters – Retail Base Rate Cases" for additional information.

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to total $227 million for 2017, $218 million for 2018, $219 million for 2019, $265 million for 2020, and $225 million for 2021. These amounts include capital expenditures related to contractual purchase commitments for capital expenditures covered under long-term service agreements. Estimated capital expenditures to comply with environmental statutes and regulations included in these amounts are $33 million, $52 million, $57 million, $55 million, and $48 million for 2017, 2018, 2019, 2020, and 2021, respectively. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's final rules and guidelines or future state plans that would limit CO_2 emissions from new, existing, 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 and monitoring of ash ponds at Plant Scholz and in accordance with the CCR Rule, which are reflected in 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 activities, are estimated

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to be $16 million, $17 million, $6 million, $26 million, and $8 million for the years 2017, 2018, 2019, 2020, and 2021, respectively. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; storm impacts; 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 generating units, to meet regulatory requirements; changes in the expected environmental compliance program; changes in FERC rules and regulations; Florida PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

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 FERC and the Florida PSC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preference stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 10 to the financial statements for additional information.

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Contractual Obligations

Contractual obligations at December 31, 2016 were as follows:

	2017	2018-2019	2020-2021	After 2021	Total
	(in millions)				
Long-term debt[(a)] –					
Principal	$87	$—	$175	$824	$1,086
Interest	42	73	65	515	695
Financial derivative obligations[(b)]	12	17	—	—	29
Preference stock dividends[(c)]	9	18	18	—	45
Operating leases[(d)]	8	7	—	1	16
Purchase commitments –					
Capital[(e)]	227	437	462	—	1,126
Fuel[(f)]	261	290	162	70	783
Purchased power[(g)]	126	261	271	1,044	1,702
Other[(h)]	8	24	34	136	202
Pension and other postretirement benefit plans[(i)]	5	11	—	—	16
Total	$785	$1,138	$1,187	$2,590	$5,700

(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, 2017, 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) Includes derivative liabilities related to cash flow hedges of forecasted debt, as well as energy-related derivatives. For additional information, see Notes 1 and 10 to the financial statements.

(c) Preference stock does not mature; therefore, amounts are provided for the next five years only.

(d) Excludes a PPA accounted for as a lease, which is included in "Purchased power."

(e) The Company provides estimated capital expenditures for a five-year period, including capital expenditures associated with environmental regulations. These amounts exclude capital expenditures covered under long-term service agreements, which are reflected in "Other." At December 31, 2016, significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information.

(f) Includes commitments to purchase coal 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, 2016.

(g) The capacity and transmission related costs associated with PPAs are recovered through the purchased power capacity clause. Energy costs associated with PPAs are recovered through the fuel clause. See Notes 3 and 7 to the financial statements for additional information.

(h) Includes long-term service agreements and contracts for the procurement of limestone. Long-term service agreements include price escalation based on inflation indices. Limestone costs are recovered through the environmental cost recovery clause. See Note 3 to the financial statements for additional information.

(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.

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Cautionary Statement Regarding Forward-Looking Statements

The Company's 2016 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, customer and sales growth, economic conditions, 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 and postretirement benefit plans contributions, financing activities, start and completion of construction projects, filings with state and federal regulatory authorities, impact of the PATH Act, federal income tax benefits, 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 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, including potential tax reform legislation, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries;
- 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;
- 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 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 foreign 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.

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STATEMENTS OF INCOME
For the Years Ended December 31, 2016, 2015, and 2014
Gulf Power Company 2016 Annual Report

	2016	2015	2014
	(in millions)		
Operating Revenues:			
Retail revenues	$1,281	$1,249	$1,267
Wholesale revenues, non-affiliates	61	107	129
Wholesale revenues, affiliates	75	58	130
Other revenues	68	69	64
Total operating revenues	1,485	1,483	1,590
Operating Expenses:			
Fuel	432	445	605
Purchased power, non-affiliates	126	100	82
Purchased power, affiliates	16	35	25
Other operations and maintenance	336	354	341
Depreciation and amortization	172	141	145
Taxes other than income taxes	120	118	111
Total operating expenses	1,202	1,193	1,309
Operating Income	283	290	281
Other Income and (Expense):			
Interest expense, net of amounts capitalized	(47)	(49)	(53)
Other income (expense), net	(5)	8	9
Total other income and (expense)	(52)	(41)	(44)
Earnings Before Income Taxes	231	249	237
Income taxes	91	92	88
Net Income	140	157	149
Dividends on Preference Stock	9	9	9
Net Income After Dividends on Preference Stock	$131	$148	$140

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

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STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2016, 2015, and 2014
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	2016	2015	2014
	(in millions)		
Net Income	$140	$157	$149
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $-, $-, and $-, respectively	1	1	—
Total other comprehensive income (loss)	1	1	—
Comprehensive Income	$141	$158	$149

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

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STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2016, 2015, and 2014
Gulf Power Company 2016 Annual Report

	2016	2015	2014
	(in millions)		
Operating Activities:			
Net income	$140	$157	$149
Adjustments to reconcile net income			
to net cash provided from operating activities —			
Depreciation and amortization, total	179	152	153
Deferred income taxes	57	90	65
Pension and postretirement funding	(48)	—	(30)
Other, net	(3)	4	(4)
Changes in certain current assets and liabilities —			
-Receivables	15	33	(17)
-Fossil fuel stock	37	(6)	34
-Prepaid income taxes	(11)	32	(19)
-Other current assets	(1)	(2)	(2)
-Accounts payable	5	(22)	8
-Over recovered regulatory clause revenues	1	22	—
-Other current liabilities	8	—	7
Net cash provided from operating activities	379	460	344
Investing Activities:			
Property additions	(178)	(235)	(348)
Cost of removal net of salvage	(9)	(10)	(13)
Change in construction payables	13	(28)	12
Payments pursuant to long-term service agreements	(5)	(8)	(8)
Other investing activities	(1)	—	(1)
Net cash used for investing activities	(180)	(281)	(358)
Financing Activities:			
Increase (decrease) in notes payable, net	126	32	(26)
Proceeds —			
Common stock issued to parent	—	20	50
Capital contributions from parent company	20	4	4
Pollution control revenue bonds	—	13	42
Senior notes	—	—	200
Redemptions and repurchases —			
Senior notes	(235)	(60)	(75)
Pollution control revenue bonds	—	(13)	(29)
Payment of common stock dividends	(120)	(130)	(123)
Other financing activities	(8)	(10)	(12)
Net cash provided from (used for) financing activities	(217)	(144)	31
Net Change in Cash and Cash Equivalents	(18)	35	17
Cash and Cash Equivalents at Beginning of Year	74	39	22
Cash and Cash Equivalents at End of Year	$56	$74	$39
Supplemental Cash Flow Information:			
Cash paid (received) during the period for —			
Interest (net of $-, $6, and $5 capitalized, respectively)	$53	$52	$48
Income taxes (net of refunds)	21	(7)	44

Noncash transactions — accrued property additions at year-end	33	20	42

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

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BALANCE SHEETS
At December 31, 2016 and 2015
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Assets	2016	2015
	(in millions)	
Current Assets:		
Cash and cash equivalents	$56	$74
Receivables —		
Customer accounts receivable	72	76
Unbilled revenues	55	54
Under recovered regulatory clause revenues	17	20
Income taxes receivable, current	—	27
Other accounts and notes receivable	6	9
Affiliated	17	1
Accumulated provision for uncollectible accounts	(1)	(1)
Fossil fuel stock	71	108
Materials and supplies	55	56
Prepaid expenses	18	8
Other regulatory assets, current	44	90
Other current assets	12	14
Total current assets	422	536
Property, Plant, and Equipment:		
In service	5,140	5,045
Less accumulated provision for depreciation	1,382	1,296
Plant in service, net of depreciation	3,758	3,749
Other utility plant, net	—	62
Construction work in progress	51	48
Total property, plant, and equipment	3,809	3,859
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	58	61
Other regulatory assets, deferred	512	427
Other deferred charges and assets	21	37
Total deferred charges and other assets	591	525
Total Assets	$4,822	$4,920

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

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BALANCE SHEETS
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Liabilities and Stockholder's Equity	2016	2015
	(in millions)	
Current Liabilities:		
Securities due within one year	$87	$110
Notes payable	268	142
Accounts payable —		
Affiliated	59	55
Other	54	44
Customer deposits	35	36
Accrued taxes —		
Accrued income taxes	1	4
Other accrued taxes	19	9
Accrued interest	8	9
Accrued compensation	40	36
Deferred capacity expense, current	22	22
Other regulatory liabilities, current	16	22
Liabilities from risk management activities	9	49
Other current liabilities	31	29
Total current liabilities	649	567
Long-Term Debt (See accompanying statements)	987	1,193
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	948	893
Employee benefit obligations	96	129
Deferred capacity expense	119	141
Asset retirement obligations	120	113
Other cost of removal obligations	249	233
Other regulatory liabilities, deferred	47	47
Other deferred credits and liabilities	71	102
Total deferred credits and other liabilities	1,650	1,658
Total Liabilities	3,286	3,418
Preference Stock (See accompanying statements)	147	147
Common Stockholder's Equity (See accompanying statements)	1,389	1,355
Total Liabilities and Stockholder's Equity	$4,822	$4,920

Commitments and Contingent Matters (See notes)
The accompanying notes are an integral part of these financial statements.

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STATEMENTS OF CAPITALIZATION
At December 31, 2016 and 2015
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	2016	2015	2016	2015
	(in millions)		(percent of total)	
Long-Term Debt:				
Long-term notes payable —				
5.30% due 2016	$—	$110		
2.93 to 5.90% due 2017	87	85		
4.75% due 2020	175	175		
3.10% to 5.75% due 2022-2051	515	640		
Total long-term notes payable	777	1,010		
Other long-term debt —				
Pollution control revenue bonds —				
1.15% to 4.45% due 2022-2049	227	227		
Variable rates (0.75% to 0.84% at 1/1/17) due 2022-2042	82	82		
Total other long-term debt	309	309		
Unamortized debt discount	(5)	(8)		
Unamortized debt issuance expense	(7)	(8)		
Total long-term debt (annual interest requirement — $42 million)	1,074	1,303		
Less amount due within one year	87	110		
Long-term debt excluding amount due within one year	987	1,193	39.1 %	44.3 %
Preferred and Preference Stock:				
Authorized — 20,000,000 shares — preferred stock				
— 10,000,000 shares — preference stock				
Outstanding — $100 par or stated value				
— 6% preference stock — 550,000 shares (non-cumulative)	54	54		
— 6.45% preference stock — 450,000 shares (non-cumulative)	44	44		
— 5.60% preference stock — 500,000 shares (non-cumulative)	49	49		
Total preference stock (annual dividend requirement — $9 million)	147	147	5.8	5.4
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized — 20,000,000 shares				
Outstanding — 5,642,717 shares	503	503		
Paid-in capital	589	567		
Retained earnings	296	285		
Accumulated other comprehensive loss	1	—		
Total common stockholder's equity	1,389	1,355	55.1	50.3
Total Capitalization	$2,523	$2,695	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, 2016, 2015, and 2014
Gulf Power Company 2016 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, 2013	5	$ 433	$ 553	$ 250	$ (1)	$1,235
Net income after dividends on preference stock	—	—	—	140	—	140
Issuance of common stock	—	50	—	—	—	50
Capital contributions from parent company	—	—	7	—	—	7
Cash dividends on common stock	—	—	—	(123)	—	(123)
Balance at December 31, 2014	5	483	560	267	(1)	1,309
Net income after dividends on preference stock	—	—	—	148	—	148
Issuance of common stock	1	20	—	—	—	20
Capital contributions from parent company	—	—	7	—	—	7
Other comprehensive income (loss)	—	—	—	—	1	1
Cash dividends on common stock	—	—	—	(130)	—	(130)
Balance at December 31, 2015	6	503	567	285	—	1,355
Net income after dividends on preference stock	—	—	—	131	—	131
Capital contributions from parent company	—	—	22	—	—	22
Other comprehensive income (loss)	—	—	—	—	1	1
Cash dividends on common stock	—	—	—	(120)	—	(120)
Balance at December 31, 2016	6	$ 503	$ 589	$ 296	$ 1	$1,389

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

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1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES
General
Gulf Power Company (the Company) is a wholly-owned subsidiary of Southern Company, which is the parent company of the Company and three other traditional electric operating companies, as well as Southern Power, Southern Company Gas (as of July 1, 2016), SCS, Southern LINC, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, PowerSecure (as of May 9, 2016), Inc. (PowerSecure), and other direct and indirect subsidiaries. The traditional electric operating companies – the Company, Alabama Power, Georgia Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. The Company provides electric service to retail customers in northwest Florida and to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. Southern Company Gas distributes natural gas through utilities in seven states and is involved in several other complementary businesses including gas marketing services, wholesale gas services, and gas midstream operations. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. Southern LINC 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. PowerSecure is a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure.
The equity method is used for entities in which the Company has significant influence but does not control.
The Company is subject to regulation by the FERC and the Florida 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
In 2014, the FASB issued ASC 606, Revenue from Contracts with Customers, replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the guidance is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.
While the Company expects most of its revenue to be included in the scope of ASC 606, it has not fully completed its evaluation of such arrangements. The majority of the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term. For such arrangements, the Company generally expects that the revenue from contracts with these customers will continue to be equivalent to the electricity supplied and billed in that period (including unbilled revenues) and the adoption of ASC 606 will not result in a significant shift in the timing of revenue recognition for such sales.
The Company's ongoing evaluation of other revenue streams and related contracts includes longer term contractual commitments and unregulated sales to customers. Some revenue arrangements, such as certain PPAs and alternative revenue programs, are expected to be excluded from the scope of ASC 606 and therefore, be accounted for and presented separately from revenues under ASC 606 on the Company's financial statements. In addition, the power and utilities industry is currently addressing other specific industry issues, including the applicability of ASC 606 to contributions in aid of construction (CIAC). If final implementation guidance indicates CIAC will be accounted for under ASC 606 and offsetting regulatory treatment is not permitted, it could have a material impact on the Company's

financial statements.
The new standard is effective for interim and annual reporting periods beginning after December 15, 2017. The Company must select a transition method to be applied either retrospectively to each prior reporting period presented or retrospectively with a cumulative effect adjustment to retained earnings at the date of initial adoption. As the ultimate impact of the new standard has not yet been determined, the Company has not elected its transition method.
On February 25, 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842) (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged. ASU 2016-02 is

effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company is currently evaluating the new standard and has not yet determined its ultimate impact; however, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.
On March 30, 2016, the FASB issued ASU No. 2016-09, Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting (ASU 2016-09). ASU 2016-09 changes the accounting for income taxes and the cash flow presentation for share-based payment award transactions effective for fiscal years beginning after December 15, 2016. The new guidance requires all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation to be recognized as income tax expense or benefit in the income statement. Previously, the Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities rather than net cash provided from financing activities on the statement of cash flows. The Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. The Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of the Company. See Notes 5, 8, and 11 for disclosures impacted by ASU 2016-09.
On October 24, 2016, the FASB issued ASU No. 2016-16, Income Taxes (Topic 740), Intra-Entity Transfers of Assets Other Than Inventory (ASU 2016-16). Current GAAP prohibits the recognition of current and deferred income taxes for an affiliate asset transfer until the asset has been sold to an outside party. ASU 2016-16 requires an entity to recognize the income tax consequences of an affiliate transfer of an asset other than inventory when the transfer occurs. ASU 2016-16 is effective for annual reporting periods beginning after December 15, 2017 and interim periods within those annual periods. The amendments will be applied on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. The Company is currently assessing the impact of the standard on its financial statements and has not yet determined its ultimate impact.

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 $80 million, $81 million, and $80 million during 2016, 2015, and 2014, 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 operating agreements with Georgia Power and Mississippi Power under which the Company owns a portion of Plant Scherer and Plant Daniel, respectively. Georgia Power operates Plant Scherer and Mississippi Power operates Plant Daniel. The Company reimbursed Georgia Power $8 million, $12 million, and $9 million and Mississippi Power $26 million, $27 million, and $31 million in 2016, 2015, and 2014, respectively, for its proportionate share of related expenses. See Note 4 and Note 7 under "Operating Leases" for additional information.
The Company has an agreement with Alabama Power under which Alabama Power made transmission system upgrades to ensure firm delivery of energy under a non-affiliate PPA from a combined cycle plant located in Alabama. Payments by the Company to Alabama Power for the improvements were $12 million, $14 million, and $12 million in 2016, 2015, and 2014, respectively, and are expected to be approximately $10 million annually for 2017 through 2023, when the PPA expires. These costs have been approved for recovery by the Florida PSC through the Company's purchased power capacity cost recovery clause and by the FERC in the transmission facilities cost allocation tariff.

In 2016, the Company purchased a turbine rotor assembly from Southern Power for $6.8 million.
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 2016, 2015, or 2014.
The traditional electric 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.

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Regulatory Assets and Liabilities

The Company is subject to accounting requirements 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:

	2016	2015	Note
	(in millions)		
Retiree benefit plans, net	$160	$147	(a,b)
PPA charges	141	163	(b,c)
Closure of ash ponds	75	29	(b,d)
Remaining book value of retired assets	66	4	(e)
Deferred income tax charges	56	59	(f)
Environmental remediation	44	46	(b,d)
Regulatory asset, offset to other cost of removal	29	29	(g)
Deferred return on transmission upgrades	25	10	(g)
Fuel-hedging assets, net	24	104	(b,h)
Other regulatory assets, net	18	16	(i)
Loss on reacquired debt	18	15	(j)
Asset retirement obligations, net	7	(1)	(b,f)
Other cost of removal obligations	(278)	(262)	(f)
Property damage reserve	(40)	(38)	(e)
Over recovered regulatory clause revenues	(23)	(22)	(k)
Deferred income tax credits	(2)	(3)	(f)
Total regulatory assets (liabilities), net	$320	$296	

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

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

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

(c) Recovered over the life of the PPA for periods up to seven years.

(d) Recovered through the environmental cost recovery clause when the remediation or the work is performed.

(e) Recorded and recovered or amortized as approved by the Florida PSC.

(f) 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 65 years. Asset retirement and removal assets and liabilities will be settled and trued up following completion of the related activities.

(g) Recorded as authorized by the Florida PSC in a settlement agreement approved in December 2013 (2013 Rate Case Settlement Agreement). See Note 3 for additional information.

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

(i) Comprised primarily of vacation pay. Other regulatory assets costs, with the exception of vacation pay, are recorded and recovered or amortized as approved by the Florida PSC. Vacation pay, including banked holiday pay, does not earn a return as offset in rate base by a corresponding liability; it is recorded as earned by employees and recovered as paid, generally within one year.

(j)

Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 40 years.

(k) Recorded and recovered or amortized as approved by the Florida PSC, generally within one year.

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.

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Revenues
Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract period. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. The Company continuously monitors the over or under recovered fuel cost balance in light of the inherent variability in fuel costs. The Company is required to notify the Florida PSC if the projected fuel cost over or under recovery is expected to exceed 10% of the projected fuel revenue applicable for the period and indicate if an adjustment to the fuel cost recovery factor is being requested. The Company has similar retail cost recovery clauses for energy conservation costs, purchased power capacity costs, and environmental compliance 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. Annually, the Company petitions for recovery of projected costs including any true-up amounts from prior periods, and approved rates are implemented each January. See Note 3 under "Retail Regulatory Matters" 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 and emissions allowance costs are recovered by the Company through the fuel cost recovery and environmental cost recovery rates, respectively, approved annually by the Florida PSC.
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 and state ITCs are recognized in the period in which the credit is claimed on the state income tax return. 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:

	2016	2015
	(in millions)	
Generation	$3,001	$2,974
Transmission	706	691
Distribution	1,241	1,196
General	191	182
Plant acquisition adjustment	1	2
Total plant in service	$5,140	$5,045

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.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.5% in both 2016 and 2015 and 3.6% in 2014. Depreciation studies are conducted periodically to update the composite rates. These studies are approved by the Florida PSC and the FERC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired. As authorized by the Florida PSC in the 2013 Rate Case Settlement Agreement, the Company is allowed to reduce depreciation and record a regulatory asset in an aggregate amount up to $62.5 million between January 2014 and June 2017. See Note 3 herein under "Retail Regulatory Matters – Retail Base Rate Cases" for additional information.

Asset Retirement Obligations and Other Costs of Removal

AROs 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 an order from the Florida 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 facilities that are subject to the Disposal of Coal Combustion Residuals from Electric Utilities final rule published by the EPA in April 2015 (CCR Rule), principally ash ponds, and to the closure of an ash pond at Plant Scholz. In addition, the Company has retirement obligations related to combustion turbines at its Pea Ridge facility, various landfill sites, a barge unloading dock, asbestos removal, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, certain wireless communication towers, and certain structures authorized by the U.S. Army Corps of Engineers. 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 Florida PSC, and are reflected in the balance sheets.

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

	2016	2015
	(in millions)	
Balance at beginning of year	$130	$17
Liabilities incurred	1	105
Liabilities settled	(1)	(1)
Accretion	4	2
Cash flow revisions	2	7
Balance at end of year	$136	$130

The increase in liabilities incurred in 2015 is primarily related to AROs associated with the portion of the Company's steam generation facilities impacted by the CCR Rule and the closure of an ash pond at Plant Scholz. In connection with permitting activity related to the coal ash pond at the retired Plant Scholz facility, the Company recorded additional AROs of $29 million in 2015.

The cost estimates for AROs related to CCR are based on information as of December 31, 2016 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 for those facilities impacted by 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 with respect to compliance activities, 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.

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Allowance for Funds Used During Construction

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, 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. The average annual AFUDC rate was 5.73% for all years presented. AFUDC, net of income taxes, as a percentage of net income after dividends on preference stock was 0.00%, 10.80%, and 10.93% for 2016, 2015, and 2014, respectively.

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.

Property Damage Reserve

The Company accrues for the cost of repairing damages from major storms and other uninsured property damages, including uninsured damages to transmission and distribution facilities, generation facilities, and other property. The costs of such damage are charged to the reserve. The Florida PSC approved annual accrual to the property damage reserve is $3.5 million, with a target level for the reserve between $48 million and $55 million. The Florida PSC also authorized the Company to make additional accruals above $3.5 million at the Company's discretion. The Company accrued total expenses of $3.5 million in each of 2016, 2015, and 2014. As of December 31, 2016 and 2015, the balance in the Company's property damage reserve totaled approximately $40 million and $38 million, respectively, which is included in deferred liabilities in the balance sheets.

When the property damage reserve is inadequate to cover the cost of major storms, the Florida PSC can authorize a storm cost recovery surcharge to be applied to customer bills. As authorized in the 2013 Rate Case Settlement Agreement, the Company may recover costs associated with any tropical systems named by the National Hurricane Center through the initiation of a storm surcharge. The storm surcharge will begin, on an interim basis, 60 days following the filing of a cost recovery petition. The storm surcharge generally may not exceed $4.00/1,000 KWHs on monthly residential bills in aggregate for a calendar year. This limitation does not apply if the Company incurs in excess of $100 million in storm recovery costs that qualify for recovery in a given calendar year. This threshold amount is inclusive of the amount necessary to replenish the storm reserve to the level that existed as of December 31, 2013. See Note 3 under "Retail Regulatory Matters – Retail Base Rate Cases" for additional details of the 2013 Rate Case Settlement Agreement.

Injuries and Damages Reserve

The Company is subject to claims and lawsuits arising in the ordinary course of business. As permitted by the Florida PSC, the Company accrues for the uninsured costs of injuries and damages by charges to income amounting to $1.6 million annually. The Florida PSC has also given the Company the flexibility to increase its annual accrual above $1.6 million to the extent the balance in the reserve does not exceed $2 million and to defer expense recognition of liabilities greater than the balance in the reserve. The cost of settling claims is charged to the reserve. The injuries and damages reserve had a balance of $1.4 million at December 31, 2016, which is included in current liabilities in the balance sheets. The balance was zero at December 31, 2015. There were no liabilities in excess of the reserve balance at December 31, 2016. The Company recorded a liability with a corresponding regulatory asset of $1.7 million for estimated liabilities related to outstanding claims and suits in excess of the reserve balance at December 31, 2015, of which $1.6 million and $0.1 million are included in current liabilities and deferred credits and other liabilities in the balance sheets, respectively.

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.

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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 oil, natural gas, coal, transportation, and emissions allowances. Fuel is recorded to inventory when purchased and then expensed, at weighted average cost, as used. Fuel expense and emissions allowance costs are recovered by the Company through the fuel cost recovery and environmental cost recovery rates, respectively, approved annually by the Florida 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 9 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 Florida PSC approved fuel-hedging program result in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts that qualify as fair value hedges are marked to market through current period income and are recorded on a net basis in the statements of income. Cash flows from derivatives are classified on the statement of cash flows in the same category as the hedged item. The Florida PSC approved a stipulation and agreement that prospectively imposed a moratorium on the Company's fuel-hedging program in October 2016 through December 31, 2017. The moratorium does not have an impact on the recovery of existing hedges entered into under the previously-approved hedging program. See Note 10 for additional information regarding derivatives.

Beginning in 2016, the Company offsets fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2016.

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

Comprehensive Income

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

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). On December 19, 2016, the Company voluntarily contributed $48 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2017. 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 FERC. For the year ending December 31, 2017, no other postretirement trust 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.

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Assumptions used to determine net periodic costs:	2016	2015	2014
Pension plans			
Discount rate – benefit obligations	4.71%	4.18%	5.02%
Discount rate – interest costs	3.97	4.18	5.02
Discount rate – service costs	5.04	4.48	5.02
Expected long-term return on plan assets	8.20	8.20	8.20
Annual salary increase	4.46	3.59	3.59
Other postretirement benefit plans			
Discount rate – benefit obligations	4.51%	4.04%	4.86%
Discount rate – interest costs	3.68	4.04	4.86
Discount rate – service costs	4.88	4.38	4.86
Expected long-term return on plan assets	8.05	8.07	8.08
Annual salary increase	4.46	3.59	3.59

Assumptions used to determine benefit obligations:	2016	2015
Pension plans		
Discount rate	4.46%	4.71%
Annual salary increase	4.46	4.46
Other postretirement benefit plans		
Discount rate	4.25%	4.51%
Annual salary increase	4.46	4.46

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

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2016 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate is Reached
Pre-65	6.50 %	4.50 %	2025
Post-65 medical	5.00	4.50	2025
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, 2016 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$ 4	$ 3
Service and interest costs	—	—

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Pension Plans

The total accumulated benefit obligation for the pension plans was $460 million at December 31, 2016 and $424 million at December 31, 2015. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2016 and 2015 were as follows:

	2016	2015
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$480	$491
Service cost	12	12
Interest cost	19	20
Benefits paid	(17)	(20)
Actuarial (gain) loss	23	(23)
Balance at end of year	517	480
Change in plan assets		
Fair value of plan assets at beginning of year	420	435
Actual return (loss) on plan assets	39	4
Employer contributions	49	1
Benefits paid	(17)	(20)
Fair value of plan assets at end of year	491	420
Accrued liability	$(26)	$(60)

At December 31, 2016, the projected benefit obligations for the qualified and non-qualified pension plans were $494 million and $23 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2016 and 2015 related to the Company's pension plans consist of the following:

	2016	2015
	(in millions)	
Other regulatory assets, deferred	$153	$142
Other current liabilities	(1)	(1)
Employee benefit obligations	(25)	(59)

Presented below are the amounts included in regulatory assets at December 31, 2016 and 2015 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 2017.

	2016	2015	Estimated Amortization in 2017
	(in millions)		
Prior service cost	$3	$2	$ 1
Net (gain) loss	150	140	7
Regulatory assets	$153	$142	

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The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2016 and 2015 are presented in the following table:

	2016	2015
	(in millions)	
Regulatory assets:		
Beginning balance	$142	$146
Net (gain) loss	16	6
Change in prior service costs	2	—
Reclassification adjustments:		
Amortization of prior service costs	(1)	(1)
Amortization of net gain (loss)	(6)	(9)
Total reclassification adjustments	(7)	(10)
Total change	11	(4)
Ending balance	$153	$142

Components of net periodic pension cost were as follows:

	2016	2015	2014
	(in millions)		
Service cost	$12	$12	$10
Interest cost	19	20	19
Expected return on plan assets	(34)	(32)	(28)
Recognized net (gain) loss	6	9	5
Net amortization	1	1	1
Net periodic pension cost	$4	$10	$7

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, 2016, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2017	$ 20
2018	22
2019	23
2020	24
2021	26
2022 to 2026	149

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Other Postretirement Benefits
Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2016 and 2015 were as follows:

	2016	2015
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$81	$78
Service cost	1	1
Interest cost	3	3
Benefits paid	(4)	(4)
Actuarial (gain) loss	2	(1)
Plan amendment	—	4
Balance at end of year	83	81
Change in plan assets		
Fair value of plan assets at beginning of year	17	18
Actual return (loss) on plan assets	2	—
Employer contributions	3	3
Benefits paid	(4)	(4)
Fair value of plan assets at end of year	18	17
Accrued liability	$(65)	$(64)

Amounts recognized in the balance sheets at December 31, 2016 and 2015 related to the Company's other postretirement benefit plans consist of the following:

	2016	2015
	(in millions)	
Other regulatory assets, deferred	$11	$10
Other current liabilities	(1)	(1)
Other regulatory liabilities, deferred	(4)	(5)
Employee benefit obligations	(64)	(63)

Approximately $7 million and $5 million was included in net regulatory assets at December 31, 2016 and 2015, respectively, related to the net loss for the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost. The estimated amortization of such amounts for 2017 is immaterial.
The changes in the balance of net regulatory assets (liabilities) related to the other postretirement benefit plans for the plan years ended December 31, 2016 and 2015 are presented in the following table:

	2016	2015
	(in millions)	
Net regulatory assets (liabilities):		
Beginning balance	$ 5	$ 2
Net (gain) loss	2	1
Change in prior service costs	—	2
Total change	2	3
Ending balance	$ 7	$ 5

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

	2016	2015	2014
	(in millions)		
Service cost	$1	$1	$1
Interest cost	3	3	3
Expected return on plan assets	(1)	(1)	(1)
Net periodic postretirement benefit cost	$3	$3	$3

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)		
2017	$5	$ —	$ 5
2018	5	—	5
2019	6	(1)	5
2020	6	(1)	5
2021	6	(1)	5
2022 to 2026	30	(3)	27

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.

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The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2016 and 2015, along with the targeted mix of assets for each plan, is presented below:

	Target	2016	2015
Pension plan assets:			
Domestic equity	26 %	29 %	30 %
International equity	25	22	23
Fixed income	23	29	23
Special situations	3	2	2
Real estate investments	14	13	16
Private equity	9	5	6
Total	100 %	100 %	100 %
Other postretirement benefit plan assets:			
Domestic equity	25 %	28 %	29 %
International equity	24	21	22
Domestic fixed income	25	31	25
Special situations	3	2	2
Real estate investments	14	13	16
Private equity	9	5	6
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.
- 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, 2016 and 2015. 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

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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.
- Real estate investments, private equity, and special situations investments. Investments in real estate, private equity, and special situations are generally classified as Net Asset Value as a Practical Expedient, since the underlying assets typically do not have publicly available observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. Techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, discounted cash flow analysis, prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals. The fair value of partnerships is determined by aggregating the value of the underlying assets less liabilities.

The fair values of pension plan assets as of December 31, 2016 and 2015 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. For 2015, investments in special situations were presented in the table below based on the nature of the investment.

	Fair Value Measurements Using				
As of December 31, 2016:	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(*)	$93	$ 43	$ —	$ —	$136
International equity(*)	57	52	—	—	109
Fixed income:					
U.S. Treasury, government, and agency bonds	—	27	—	—	27
Mortgage- and asset-backed securities	—	1	—	—	1
Corporate bonds	—	47	—	—	47
Pooled funds	—	24	—	—	24
Cash equivalents and other	46	—	—	—	46
Real estate investments	14	—	—	53	67
Special situations	—	—	—	8	8

Private equity	—	—	—	25	25
Total	$210	$ 194	$ —	$ 86	$490

(*) 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.

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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(*)	$73	$ 31	$ —	$ —	$104
International equity(*)	54	45	—	—	99
Fixed income:					
U.S. Treasury, government, and agency bonds	—	21	—	—	21
Mortgage- and asset-backed securities	—	9	—	—	9
Corporate bonds	—	51	—	—	51
Pooled funds	—	23	—	—	23
Cash equivalents and other	—	7	—	—	7
Real estate investments	14	—	—	55	69
Private equity	—	—	—	29	29
Total	$141	$ 187	$ —	$ 84	$412

(*) 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, 2016 and 2015 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases.

As of December 31, 2016:	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(*)	$3	$ 2	$ —	$ —	$ 5
International equity(*)	2	2	—	—	4
Fixed income:					
U.S. Treasury, government, and agency bonds	—	1	—	—	1

Corporate bonds	—	2	—	—	2
Pooled funds	—	1	—	—	1
Cash equivalents and other	2	—	—	—	2
Real estate investments	1	—	—	2	3
Private equity	—	—	—	1	1
Total	$8	$ 8	$ —	$ 3	$ 19

(*) 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.

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	Fair Value Measurements Using				
	Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs	Net Asset Value as a Practical Expedient	
As of December 31, 2015:	(Level 1)	(Level 2)	(Level 3)	(NAV)	Total
	(in millions)				
Assets:					
Domestic equity(*)	$3	$ 1	$ —	$ —	$ 4
International equity(*)	2	2	—	—	4
Fixed income:					
U.S. Treasury, government, and agency bonds	—	1	—	—	1
Corporate bonds	—	2	—	—	2
Pooled funds	—	1	—	—	1
Cash equivalents and other	1	—	—	—	1
Real estate investments	1	—	—	2	3
Private equity	—	—	—	1	1
Total	$7	$ 7	$ —	$ 3	$ 17

(*) 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 2016, 2015, and 2014 were $5 million, $4 million, and $4 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

Environmental Matters

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up affected sites. The Company received authority from the Florida PSC to recover approved

environmental compliance costs through the environmental cost recovery clause. The Florida PSC reviews costs and adjusts rates up or down annually.
The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable. At December 31, 2016, the Company's environmental remediation liability included estimated costs of environmental remediation projects of approximately $44 million, of which approximately $4 million is included in under recovered regulatory clause revenues and other current liabilities and approximately $40 million is included in other regulatory assets, deferred and other deferred credits and

liabilities. These estimated costs primarily relate to site closure criteria by the Florida Department of Environmental Protection (FDEP) for potential impacts to soil and groundwater from herbicide applications at the Company's substations. The schedule for completion of the remediation projects is subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through the Company's environmental cost recovery clause; therefore, these liabilities have no impact on net income.

The ultimate outcome of these matters cannot be determined at this time; however, based on the currently known conditions at these sites and the nature and extent of activities relating to these sites, the Company does not believe that additional liabilities, if any, at these sites would be material to the Company's financial statements.

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 electric operating companies (including the Company) and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In April 2015, the FERC issued an order finding that the traditional electric 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 electric operating companies and in some adjacent areas. The FERC directed the traditional electric 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 electric operating companies (including the Company) and Southern Power filed a request for rehearing in May 2015 and in June 2015 filed their response with the FERC.

On December 9, 2016, the traditional electric operating companies (including the Company) and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' (including the Company's) and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies (including the Company) and in some adjacent areas. The traditional electric operating companies (including the Company) and Southern Power expect to make a compliance filing within 30 days accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.

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

Retail Regulatory Matters

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates.

Retail Base Rate Cases

In 2013, the Florida PSC approved the 2013 Rate Case Settlement Agreement among the Company and all of the intervenors to the Company's retail base rate case. Under the terms of the 2013 Rate Case Settlement Agreement, the Company (1) increased base rates approximately $35 million and $20 million annually effective January 2014 and 2015, respectively; (2) continued its authorized retail ROE midpoint (10.25%) and range (9.25% – 11.25%); and (3) accrued a return similar to AFUDC on certain transmission system upgrades placed into service after January 2014 through January 1, 2017.

The 2013 Rate Case Settlement Agreement also provides that the Company may reduce depreciation and record a regulatory asset that will be included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million from January 2014 through June 2017. In any given month, such depreciation reduction may not exceed the amount necessary for the retail ROE, as reported to the Florida PSC monthly, to reach the midpoint of the authorized retail ROE range then in effect. Recovery of the regulatory asset will occur over a period to be determined by the Florida PSC in the 2016 Rate Case, as defined below. For 2014 and 2015, the Company recognized reductions in depreciation expense of $8.4 million and $20.1 million, respectively. No net reduction in depreciation was recorded in 2016.

On October 12, 2016, the Company filed a petition (2016 Rate Case) with the Florida PSC requesting an annual increase in retail rates and charges of $106.8 million based on the projected test year of January 1, 2017 through December 31, 2017 and a retail ROE of

11% compared to the current retail ROE of 10.25%. The requested increase includes recovery of the portion of Plant Scherer Unit 3 that has been rededicated to serving retail customers following the contract expirations at the end of 2015 and May 2016. If retail recovery of Plant Scherer Unit 3 is not approved by the Florida PSC in the 2016 Rate Case, the Company may consider an asset sale. The current book value of the Company's ownership of Plant Scherer Unit 3 could exceed market value which could result in a material loss. The Florida PSC is expected to make a decision on the 2016 Rate Case in the second quarter 2017. The Company has requested that the increase in base rates, if approved by the Florida PSC, become effective in July 2017. The ultimate outcome of this matter cannot be determined at this time.

Cost Recovery Clauses

On November 2, 2016, the Florida PSC approved the Company's 2017 annual cost recovery clause rates for its fuel, purchased power capacity, environmental, and energy conservation cost recovery clauses. The net effect of the approved changes is a decrease of approximately $41 million in annual revenues effective in January 2017. In general, the decreased revenues will not have a significant impact on net income since most of the revenues will be offset by lower expenses. However, certain costs associated with the ongoing ownership and operation of Plant Scherer Unit 3 were included in the environmental cost recovery clause rate, which increased annual revenues by approximately $12 million in 2016 and is expected to increase revenues by an incremental $2 million for a total of approximately $14 million in 2017. The final disposition of these costs, and the related impact on rates, is subject to the Florida PSC's ultimate ruling on whether costs associated with Plant Scherer Unit 3 are recoverable from retail customers, which is expected to be decided in the 2016 Rate Case as discussed previously. The ultimate outcome of this matter cannot be determined at this time.

Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor for fuel and purchased power will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. The recovery provisions for environmental compliance and energy conservation include related expenses and a return on net average investment.

Retail Fuel Cost Recovery

The Company has established fuel cost recovery rates as approved by the Florida PSC. If, at any time during the year, the projected year-end fuel cost over or under recovery balance exceeds 10% of the projected fuel revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the fuel cost recovery factor is being requested.

At December 31, 2016 and 2015, the over recovered fuel balance was approximately $15 million and $18 million, respectively, which is included in other regulatory liabilities, current in the balance sheets.

Purchased Power Capacity Recovery

The Company has established purchased power capacity recovery cost rates as approved by the Florida PSC. If the projected year-end purchased power capacity cost over or under recovery balance exceeds 10% of the projected purchased power capacity revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the purchased power capacity cost recovery factor is being requested.

At December 31, 2016 and 2015, the under recovered purchased power capacity balance was immaterial.

Environmental Cost Recovery

The Florida Legislature adopted legislation for an environmental cost recovery clause, which allows an electric utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. Such environmental costs include operations and maintenance expenses, emissions allowance expense, depreciation, and a return on net average investment. This legislation also allows recovery of costs incurred as a result of an agreement between the Company and the FDEP for the purpose of ensuring compliance with ozone ambient air quality standards adopted by the EPA.

Annually, the Company seeks recovery of projected costs including any true-up amounts from prior periods. At December 31, 2016, the over recovered environmental balance of approximately $8 million, along with the current portion of projected environmental expenditures, was included in under recovered regulatory clause revenues in the balance sheet. At December 31, 2015, the over recovered environmental balance was immaterial.

In 2012, the Mississippi PSC approved Mississippi Power's request for a certificate of public convenience and necessity to construct scrubbers on Plant Daniel Units 1 and 2, which were placed in service in November 2015. These units are jointly owned by Mississippi Power and the Company, with 50% ownership each. The total cost of the project was approximately $653 million, with the Company's portion being approximately $316 million, excluding AFUDC. The Company's portion of the cost is being recovered through the environmental cost recovery clause.

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Energy Conservation Cost Recovery
Every five years, the Florida PSC establishes new numeric conservation goals covering a 10-year period for utilities to reduce annual energy and seasonal peak demand using demand-side management (DSM) programs. After the goals are established, utilities develop plans and programs to meet the approved goals. The costs for these programs are recovered through rates established annually in the energy conservation cost recovery (ECCR) clause.
At December 31, 2016, the under recovered ECCR balance was approximately $4 million, which is included in under recovered regulatory clause revenues in the balance sheet. At December 31, 2015, the over recovered ECCR balance was approximately $4 million, which is included in other regulatory liabilities, current in the balance sheet.
Other Matters
As a result of the cost to comply with environmental regulations imposed by the EPA, the Company retired its coal-fired generation at Plant Smith Units 1 and 2 (357 MWs) on March 31, 2016. The Company filed a petition with the Florida PSC requesting permission to recover the remaining net book value of Plant Smith Units 1 and 2 and the remaining materials and supplies associated with these units as of the retirement date. On August 29, 2016, the Florida PSC approved the Company's request to reclassify these costs, totaling $63 million, to a regulatory asset for recovery over a period to be decided in the 2016 Rate Case. The ultimate outcome of this matter cannot be determined at this time.
4. JOINT OWNERSHIP AGREEMENTS
The Company and Mississippi Power jointly own Plant Daniel Units 1 and 2, which together represent capacity of 1,000 MWs. Plant Daniel is a generating plant located in Jackson County, Mississippi. In accordance with the operating agreement, Mississippi Power acts as the Company's agent with respect to the construction, operation, and maintenance of these units.
The Company and Georgia Power jointly own the 818-MW capacity Plant Scherer Unit 3. Plant Scherer is a generating plant located near Forsyth, Georgia. In accordance with the operating agreement, Georgia Power acts as the Company's agent with respect to the construction, operation, and maintenance of the unit.
At December 31, 2016, the Company's percentage ownership and investment in these jointly-owned facilities were as follows:

	Plant Scherer Unit 3 (coal)	Plant Daniel Units 1 & 2 (coal)
	(in millions)	
Plant in service	$398	$680
Accumulated depreciation	143	202
Construction work in progress	7	7
Company ownership	25 %	50 %

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

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Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2016	2015	2014
	(in millions)		
Federal -			
Current	$34	$(3)	$ 23
Deferred	45	80	52
	79	77	75
State -			
Current	—	5	—
Deferred	12	10	13
	12	15	13
Total	$91	$92	$ 88

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:

	2016	2015
	(in millions)	
Deferred tax liabilities-		
Accelerated depreciation	$834	$812
Property basis differences	123	133
Pension and other employee benefits	58	39
Regulatory assets	45	16
Regulatory assets associated with employee benefit obligations	65	59
Regulatory assets associated with asset retirement obligations	55	40
Other	12	10
Total	1,192	1,109
Deferred tax assets-		
Federal effect of state deferred taxes	37	33
Postretirement benefits	26	26
Pension and other employee benefits	72	65
Property reserve	17	15
Asset retirement obligations	55	40
Alternative minimum tax carryforward	18	18
Other	19	19
Total	244	216
Accumulated deferred income taxes	$948	$893

The application of bonus depreciation provisions in current tax law significantly increased deferred tax liabilities related to accelerated depreciation in 2016 and 2015.

At December 31, 2016, tax-related regulatory assets to be recovered from customers were $58 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, 2016, the tax-related regulatory liabilities to be credited to customers were $2 million. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and unamortized ITCs.

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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 are not material for the periods presented. At December 31, 2016, 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:

	2016	2015	2014
Federal statutory rate	35.0%	35.0%	35.0%
State income tax, net of federal deduction	3.4	3.9	3.5
Non-deductible book depreciation	0.6	0.5	0.4
Differences in prior years' deferred and current tax rates	(0.1)	(0.1)	(0.1)
AFUDC equity	—	(1.8)	(1.8)
Other, net	0.6	(0.6)	0.1
Effective income tax rate	39.5%	36.9%	37.1%

The increase in the Company's 2016 effective tax rate is primarily the result of the decrease in nontaxable AFUDC equity.

On March 30, 2016, the FASB issued ASU 2016-09, which changes the accounting for income taxes for share-based payment award transactions. Entities are required to recognize all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation as income tax expense or benefit in the income statement. The adoption of ASU 2016-09 did not have a material impact on the Company's overall effective tax rate. See Note 1 under "Recently Issued Accounting Standards" for additional information.

Unrecognized Tax Benefits

The Company has no material unrecognized tax benefits for the periods presented. 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, but an estimate of the range of reasonably possible outcomes cannot be determined at this time.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013, 2014, and 2015 federal income tax returns and has received partial acceptance letters from the IRS; however, the IRS has not finalized its audits. Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2011.

6. FINANCING

Securities Due Within One Year

At December 31, 2016 and 2015, the Company had $87 million and $110 million of long-term debt due within one year, respectively.

Maturities through 2021 applicable to total long-term debt include $87 million in 2017 and $175 million in 2020. There are no scheduled maturities in 2018, 2019, or 2021.

Bank Term Loans

In May 2016, the Company entered into an 11-month floating rate bank loan bearing interest based on one-month LIBOR. This short-term loan was for $100 million aggregate principal amount and the proceeds were used to repay existing indebtedness and for working capital and other general corporate purposes.

This bank loan has a covenant that limits debt levels to 65% of total capitalization, as defined in the agreement. For purposes of this definition, debt excludes certain hybrid securities. At December 31, 2016, the Company was in compliance with its debt limit.

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Senior Notes

At December 31, 2016 and 2015, the Company had a total of $777 million and $1.01 billion of senior notes outstanding, respectively. These senior notes are effectively subordinate to all secured debt of the Company, which totaled approximately $41 million at both December 31, 2016 and 2015.

In May 2016, the Company redeemed $125 million aggregate principal amount of its Series 2011A 5.75% Senior Notes due June 1, 2051.

Pollution Control Revenue Bonds

Pollution control revenue bond obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bond obligations outstanding at December 31, 2016 and 2015 was $309 million.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. 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 or involuntary dissolution. No shares of preferred stock or Class A preferred stock were outstanding at December 31, 2016. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. Certain series of the preference stock are subject to redemption at the option of the Company on or after a specified date (typically five or 10 years after the date of issuance) at a redemption price equal to 100% of the liquidation amount of the preference stock. In addition, certain series of the preference stock may be redeemed earlier at a redemption price equal to 100% of the liquidation amount plus a make-whole premium based on the present value of the liquidation amount and future dividends.

In January 2015, the Company issued 200,000 shares of common stock to Southern Company and realized proceeds of $20 million. The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

Subsequent to December 31, 2016, the Company issued 1,750,000 shares of common stock to Southern Company and realized proceeds of $175 million. The proceeds were used for general corporate purposes, including the Company's continuous construction program.

Dividend Restrictions

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

Assets Subject to Lien

The Company has granted a lien on its property at Plant Daniel in connection with the issuance of two series of pollution control revenue bonds with an aggregate outstanding principal amount of $41 million as of December 31, 2016. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its subsidiaries.

Bank Credit Arrangements

At December 31, 2016, committed credit arrangements with banks were as follows:

Expires				Executable Term Loans		Expires Within One Year	
2017	2018	Total	Unused	One Year	Two Years	Term Out	No Term Out
		(in millions)		(in millions)			

(in millions)				(in millions)			
$85	$195	$280	$ 280	$ 45	$ —	$25	$ 60

Most of the bank credit arrangements require payment of commitment fees based on the unused portion of the commitments. Commitment fees average less than $^{1}/_{4}$ of 1% for the Company.

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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.

Most of these bank credit arrangements contain covenants that limit the Company's debt level to 65% of total capitalization, as defined in the arrangements. For purposes of these definitions, debt excludes certain hybrid securities. At December 31, 2016, the Company was in compliance with these covenants.

Most of the $280 million of unused credit arrangements with banks provide liquidity support to the Company's pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2016 was approximately $82 million. In addition, at December 31, 2016, the Company had $86 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

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

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period	
	Amount Outstanding (in millions)	Weighted Average Interest Rate
December 31, 2016:		
Commercial paper	$168	1.1%
Short-term bank debt	100	1.5%
Total	$268	1.2%
December 31, 2015:		
Commercial paper	$142	0.7%

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 fuel which are not recognized on the balance sheets. In 2016, 2015, and 2014, the Company incurred fuel expense of $432 million, $445 million, and $605 million, 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, energy, and transmission, some of which are accounted for as operating leases. The energy-related costs associated with PPAs are recovered through the fuel cost recovery clause. The capacity and transmission-related costs associated with PPAs are recovered through the purchased power capacity cost recovery clause. Capacity expense under a PPA accounted for as an operating lease was $75 million for both 2016 and 2015 and $50 million for 2014.

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Estimated total minimum long-term commitments at December 31, 2016 were as follows:

	Operating Lease PPA
	(in millions)
2017	$ 79
2018	79
2019	79
2020	79
2021	79
2022 and thereafter	112
Total	$ 507

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 electric operating companies and Southern Power. Under these agreements, each of the traditional electric 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 electric operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

In addition to the operating lease PPA discussed above, the Company has other operating lease agreements with various terms and expiration dates. Total rent expense was $9 million, $14 million, and $15 million for 2016, 2015, and 2014, respectively.

Estimated total minimum lease payments under these operating leases at December 31, 2016 were as follows:

	Minimum Lease Payments		
	Barges & Railcars	Other	Total
	(in millions)		
2017	$7	$ 1	$ 8
2018	5	1	6
2019	—	1	1
2020	—	—	—
2021	—	—	—
2022 and thereafter	—	1	1
Total	$12	$ 4	$ 16

The Company and Mississippi Power jointly entered into an operating lease agreement for aluminum railcars for the transportation of coal to Plant Daniel. The Company has the option to purchase the railcars at the greater of lease termination value or fair market value or to renew the leases at the end of the lease term. The Company and Mississippi Power also have separate lease agreements for other railcars that do not include purchase options. The Company's 50% share of the lease costs, charged to fuel inventory and recovered through the retail fuel cost recovery clause, was $2 million in both 2016 and 2015 and $3 million in 2014. The Company's total annual railcar lease payments for 2017 are $2 million and are immaterial for 2018 through 2020.

In addition to railcar leases, the Company has operating lease agreements for barges and towboats for the transport of coal to Plant Crist. The Company has the option to renew the leases at the end of the lease term. The Company's lease costs, charged to fuel inventory and recovered through the retail fuel cost recovery clause, were $5 million in 2016 and $10 million in both 2015 and 2014. The Company's annual barge and towboat payments for 2017 and 2018 are expected to be approximately $5 million each year.

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8. STOCK COMPENSATION
Stock-Based Compensation
Stock-based compensation primarily in the form of Southern Company 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, 2016, there were 184 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.
The weighted average grant-date fair value of stock options granted during 2014 derived using the Black-Scholes stock option pricing model was $2.20.
The compensation cost related to the grant of Southern Company stock options to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. Compensation cost and related tax benefits recognized in the Company's financial statements were not material for any year presented. As of December 31, 2016, 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, 2016, 2015, and 2014 was $3 million, $2 million, and $5 million, respectively. No cash proceeds are received by the Company upon the exercise of stock options. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $1 million for the years ended December 31, 2016 and 2015 and $2 million for 2014. Prior to the adoption of ASU 2016-09, the excess tax benefits related to the exercise of stock options were recognized in the Company's financial statements with a credit to equity. Upon the adoption of ASU 2016-09, beginning in 2016, all tax benefits related to the exercise of stock options are recognized in income. As of December 31, 2016, the aggregate intrinsic value for the options outstanding and options exercisable was $6 million and $5 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. 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, 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, 2016, 2015, and 2014, employees of the Company were granted performance share units of 57,333, 48,962, and 37,829, respectively. The weighted average grant-date fair value of TSR-based performance share units granted during 2016, 2015, and 2014, 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 $45.18, $46.38, and $37.54, respectively. The weighted average grant-date fair value of both EPS-based and ROE-based performance share units granted during 2016 and 2015 was $48.83 and $47.75, respectively.

For the years ended December 31, 2016, 2015, and 2014, total compensation cost for performance share units recognized in income was $3 million, $2 million, and $1 million, respectively. The related tax benefit also recognized in income was $1 million in 2016 and 2015 and immaterial in 2014. The compensation cost related to the grant of Southern Company performance share units to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2016, $2 million of total unrecognized compensation cost related to performance share award units will be recognized over a weighted-average period of approximately 22 months.

9. FAIR VALUE MEASUREMENTS

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

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

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

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As of December 31, 2016, 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:

As of December 31, 2016:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in millions)			
Assets:				
Cash equivalents	$20	$ —	$ —	$ 20
Energy-related derivatives	—	5	—	5
Total	$20	$ 5	$ —	$ 25
Liabilities:				
Energy-related derivatives	$—	$ 29	$ —	$ 29

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:

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)	Total
	(in millions)			
Assets:				
Interest rate derivatives	$—	$ 1	$ —	$1
Cash equivalents	18	—	—	18
Total	$18	$ 1	$ —	$19
Liabilities:				
Energy-related derivatives	$—	$ 100	$ —	$100

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 10 for additional information on how these derivatives are used.

NOTES (continued)
Gulf Power Company 2016 Annual Report

As of December 31, 2016 and 2015, 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:		
2016	$1,074	$1,097
2015	$1,303	$1,339

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.

10. 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 may enter 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 net basis. See Note 9 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 energy-related commodity prices. The Company manages fuel-hedging programs, implemented per the guidelines of the Florida PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility. The Florida PSC approved a stipulation and agreement that prospectively imposed a moratorium on the Company's fuel-hedging program in October 2016 through December 31, 2017. The moratorium does not have an impact on the recovery of existing hedges entered into under the previously-approved hedging program.

Energy-related derivative contracts are accounted for under one of three methods:

- Regulatory Hedges — Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the fuel cost recovery clause.
- Cash Flow Hedges — Gains and losses on energy-related derivatives designated as cash flow hedges (which are mainly used to hedge anticipated purchases and sales) are initially deferred in OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- Not Designated — Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

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

At December 31, 2016, the net volume of energy-related derivative contracts for natural gas positions totaled 51 million mmBtu for the Company, with the longest hedge date of 2020 over which it is hedging its exposure to the variability in future cash flows for forecasted transactions.

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

NOTES (continued)
Gulf Power Company 2016 Annual Report

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, 2016, 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, 2016
(in millions)				(in millions)
Cash Flow Hedges of Forecasted Debt				
$ 80	3-month LIBOR	2.32%	December 2026	$ —

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2017 are immaterial. The Company has deferred gains and losses that are expected to be amortized into earnings through 2026.

Derivative Financial Statement Presentation and Amounts

The Company enters into energy-related and interest rate derivative contracts that may contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. At December 31, 2016, fair value amounts of derivative assets and liabilities on the balance sheets are presented net to the extent that there are netting arrangements or similar agreements with the counterparties. At December 31, 2015, the fair value amounts of derivative instruments were presented gross on the balance sheets.

At December 31, 2016 and 2015, the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

Derivative Category and Balance Sheet Location	2016 Assets	2016 Liabilities	2015 Assets	2015 Liabilities
	(in millions)			
Derivatives designated as hedging instruments for regulatory purposes				
Energy-related derivatives:				
Other current assets/Liabilities from risk management activities	$4	$ 12	$—	$ 49
Other deferred charges and assets/Other deferred credits and liabilities	1	17	—	51
Total derivatives designated as hedging instruments for regulatory purposes	$5	$ 29	$—	$ 100
Derivatives designated as hedging instruments in cash flow and fair value hedges				
Interest rate derivatives:				
Other current assets/Liabilities from risk management activities	—	—	1	—
Gross amounts recognized	$5	$ 29	$1	$ 100
Gross amounts offset	$(4)	$ (4)	$—	$ —
Net amounts recognized in the Balance Sheets(*)	$1	$ 25	$1	$ 100

(*) At December 31, 2015, the fair value amounts for derivative contracts subject to netting arrangements were presented gross on the balance sheet.

Energy-related derivatives not designated as hedging instruments were immaterial on the balance sheets for 2016 and 2015.

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At December 31, 2016 and 2015, the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivatives designated as regulatory hedging instruments and deferred were as follows:

Derivative Category	Unrealized Losses Balance Sheet Location	2016	2015	Unrealized Gains Balance Sheet Location	2016	2015
		(in millions)			(in millions)	
Energy-related derivatives:(*)	Other regulatory assets, current	$(9)	$(49)	Other regulatory liabilities, current	$ 1	$ —
	Other regulatory assets, deferred	(16)	(51)	Other regulatory liabilities, deferred	—	—
Total energy-related derivative gains (losses)		$(25)	$(100)		$ 1	$ —

(*) At December 31, 2016, the unrealized gains and losses for derivative contracts subject to netting arrangements were presented net on the balance sheet. At December 31, 2015, the unrealized gains and losses for derivative contracts were presented gross on the balance sheet.

For the years ended December 31, 2016, 2015, and 2014, the pre-tax effects of interest rate derivatives designated as cash flow hedging instruments on the statements of income were as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)			Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
					Amount		
Derivative Category	2016	2015	2014	Statements of Income Location	2016	2015	2014
	(in millions)				(in millions)		
Interest rate derivatives	$ —	$ 1	$ —	Interest expense, net of amounts capitalized	$(1)	$(1)	$(1)

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

For the years ended December 31, 2016, 2015, and 2014, the pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of income were 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, 2016, the Company's collateral posted with its derivative counterparties was not material.

At December 31, 2016, the fair value of derivative liabilities with contingent features, including 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 because of joint and several liability features underlying these derivatives, was immaterial.

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.

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NOTES (continued)
Gulf Power Company 2016 Annual Report

11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)
Summarized quarterly financial information for 2016 and 2015 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preference Stock
	(in millions)		
March 2016	$335	$ 65	$ 29
June 2016	365	74	34
September 2016	436	90	45
December 2016	349	54	23
March 2015	$357	$ 72	$ 37
June 2015	384	69	35
September 2015	429	91	48
December 2015	313	58	28

In accordance with the adoption of ASU 2016-09 (see Note 1 under "Recently Issued Accounting Standards"), previously reported amounts for income tax expense were reduced by an immaterial amount for the first, second, and third quarters of 2016.
The Company's business is influenced by seasonal weather conditions.

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SELECTED FINANCIAL AND OPERATING DATA 2012-2016
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	2016	2015	2014	2013	2012
Operating Revenues (in millions)	$ 1,485	$ 1,483	$ 1,590	$ 1,440	$ 1,440
Net Income After Dividends on Preference Stock (in millions)	$ 131	$ 148	$ 140	$ 124	$ 126
Cash Dividends on Common Stock (in millions)	$ 120	$ 130	$ 123	$ 115	$ 116
Return on Average Common Equity (percent)	9.52	11.11	11.02	10.30	10.92
Total Assets (in millions)[(a)(b)]	$ 4,822	$ 4,920	$ 4,697	$ 4,321	$ 4,167
Gross Property Additions (in millions)	$ 179	$ 247	$ 361	$ 305	$ 325
Capitalization (in millions):					
Common stock equity	$ 1,389	$ 1,355	$ 1,309	$ 1,235	$ 1,181
Preference stock	147	147	147	147	98
Long-term debt[(a)]	987	1,193	1,362	1,150	1,178
Total (excluding amounts due within one year)	$ 2,523	$ 2,695	$ 2,818	$ 2,532	$ 2,457
Capitalization Ratios (percent):					
Common stock equity	55.1	50.3	46.5	48.8	48.1
Preference stock	5.8	5.4	5.2	5.8	4.0
Long-term debt[(a)]	39.1	44.3	48.3	45.4	47.9
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	398,501	393,149	388,292	383,980	379,922
Commercial	56,091	55,460	54,892	54,567	53,808
Industrial	254	248	260	260	264
Other	569	614	603	582	577
Total	455,415	449,471	444,047	439,389	434,571
Employees (year-end)	1,352	1,391	1,384	1,410	1,416

(a) A reclassification of debt issuance costs from Total Assets to Long-term debt of $8 million, $8 million, and $8 million is reflected for years 2014, 2013, and 2012, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(b) A reclassification of deferred tax assets from Total Assets of $3 million, $8 million, and $2 million is reflected for years 2014, 2013, and 2012, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

SELECTED FINANCIAL AND OPERATING DATA 2012-2016 (continued)
Gulf Power Company 2016 Annual Report

	2016	2015	2014	2013	2012
Operating Revenues (in millions):					
Residential	$714	$698	$700	$632	$609
Commercial	410	403	408	395	390
Industrial	152	144	153	139	140
Other	5	4	6	4	5
Total retail	1,281	1,249	1,267	1,170	1,144
Wholesale — non-affiliates	61	107	129	109	107
Wholesale — affiliates	75	58	130	100	124
Total revenues from sales of electricity	1,417	1,414	1,526	1,379	1,375
Other revenues	68	69	64	61	65
Total	$1,485	$1,483	$1,590	$1,440	$1,440
Kilowatt-Hour Sales (in millions):					
Residential	5,358	5,365	5,362	5,089	5,054
Commercial	3,869	3,898	3,838	3,810	3,859
Industrial	1,830	1,798	1,849	1,700	1,725
Other	25	25	26	21	25
Total retail	11,082	11,086	11,075	10,620	10,663
Wholesale — non-affiliates	751	1,040	1,670	1,163	977
Wholesale — affiliates	2,784	1,906	3,284	3,127	4,370
Total	14,617	14,032	16,029	14,910	16,010
Average Revenue Per Kilowatt-Hour (cents):					
Residential	13.33	13.01	13.06	12.43	12.06
Commercial	10.60	10.34	10.64	10.37	10.11
Industrial	8.31	8.01	8.28	8.15	8.14
Total retail	11.56	11.27	11.44	11.02	10.73
Wholesale	3.85	5.60	5.23	4.87	4.31
Total sales	9.69	10.08	9.52	9.25	8.59
Residential Average Annual					
Kilowatt-Hour Use Per Customer	13,515	13,705	13,865	13,301	13,303
Residential Average Annual					
Revenue Per Customer	$1,801	$1,783	$1,811	$1,653	$1,604
Plant Nameplate Capacity					
Ratings (year-end) (megawatts)	2,278	2,583	2,663	2,663	2,663
Maximum Peak-Hour Demand (megawatts):					
Winter	2,033	2,488	2,684	1,729	2,130
Summer	2,503	2,491	2,424	2,356	2,344
Annual Load Factor (percent)	54.7	54.9	51.1	55.9	56.3
Plant Availability Fossil-Steam (percent)	81.0	88.3	89.4	92.8	82.5
Source of Energy Supply (percent):					
Coal	31.0	33.5	44.5	36.4	34.6
Gas	23.2	25.6	22.2	23.0	23.5
Purchased power —					
From non-affiliates	41.1	30.4	28.9	37.0	40.2
From affiliates	4.7	10.5	4.4	3.6	1.7
Total	100.0	100.0	100.0	100.0	100.0

MISSISSIPPI POWER COMPANY
FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Mississippi Power Company 2016 Annual Report

The management of Mississippi 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, 2016.

/s/ Anthony L. Wilson
Anthony L. Wilson
Chairman, President, and Chief Executive Officer

/s/ Moses H. Feagin
Moses H. Feagin
Vice President, Chief Financial Officer, and Treasurer

February 21, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors of
Mississippi Power Company

We have audited the accompanying balance sheets and statements of capitalization of Mississippi Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2016 and 2015, and the related statements of operations, comprehensive income (loss), common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2016. 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 II-427 to II-475) present fairly, in all material respects, the financial position of Mississippi Power Company as of December 31, 2016 and 2015, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 3 to the financial statements, the Mississippi Public Service Commission rate recovery process associated with the Kemper Integrated Coal Gasification Combined Cycle Project may have a material impact on the Company's financial statements.
/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 21, 2017

DEFINITIONS

Term	Meaning
2012 MPSC CPCN Order	A detailed order issued by the Mississippi PSC in April 2012 confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing acquisition, construction, and operation of the Kemper IGCC
AFUDC	Allowance for funds used during construction
Alabama Power	Alabama Power Company
ARO	Asset retirement obligation
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
Baseload Act	State of Mississippi legislation designed to enhance the Mississippi PSC's authority to facilitate development and construction of baseload generation in the State of Mississippi
CCR	Coal combustion residuals
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
CPCN	Certificate of public convenience and necessity
CWIP	Construction work in progress
DOE	U.S. Department of Energy
ECM	Energy cost management clause
ECO	Environmental compliance overview
EPA	U.S. Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	U.S. generally accepted accounting principles
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
IGCC	Integrated coal gasification combined cycle
IRS	Internal Revenue Service
ITC	Investment tax credit
Kemper IGCC	IGCC facility under construction in Kemper County, Mississippi
KWH	Kilowatt-hour
LIBOR	London Interbank Offered Rate
Mirror CWIP	A regulatory liability used by Mississippi Power to record customer refunds resulting from a 2015 Mississippi PSC order
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MPUS	Mississippi Public Utilities Staff
MRA	Municipal and Rural Associations
MW	Megawatt
OCI	Other comprehensive income
PEP	Performance evaluation plan
Plant Daniel Units 3 and 4	Combined cycle Units 3 and 4 at Plant Daniel
power pool	The operating arrangement whereby the integrated generating resources of the traditional electric operating companies and Southern Power (excluding subsidiaries) are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power purchase agreement
PSC	Public Service Commission

DEFINITIONS
(continued)

Term	Meaning
ROE	Return on equity
S&P	S&P Global Ratings, a division of S&P Global Inc.
scrubber	Flue gas desulfurization system
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	U.S. Securities and Exchange Commission
SMEPA	South Mississippi Electric Power Association (now known as Cooperative Energy)
Southern Company	The Southern Company
Southern Company Gas	Southern Company Gas (formerly known as AGL Resources Inc.) and its subsidiaries
Southern Company system	Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), Southern Electric Generating Company, Southern Nuclear, SCS, Southern LINC, PowerSecure, Inc. (as of May 9, 2016), and other subsidiaries
Southern LINC	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
SRR	System Restoration Rider
traditional electric operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power Company

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Mississippi Power Company 2016 Annual Report
OVERVIEW
Business Activities
Mississippi Power Company (the Company) operates as a vertically integrated utility providing electric service to retail customers within its traditional service territory located within the State of Mississippi and to wholesale customers in the Southeast.
Many factors affect the opportunities, challenges, and risks of the Company's business of providing electric service. These factors include the Company's ability to maintain and grow energy sales and to operate in a constructive regulatory environment that provides timely recovery of prudently-incurred costs. These costs include those related to the completion and operation of the Kemper IGCC, projected long-term demand growth, reliability, fuel, and stringent environmental standards, as well as ongoing capital expenditures required for maintenance and restoration following major storms. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.
The Company continues to progress toward completing the construction and start-up of the Kemper IGCC, which was approved by the Mississippi PSC in the 2010 CPCN proceedings, subject to a construction cost cap of $2.88 billion, net of $245 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (Initial DOE Grants) and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, AFUDC, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when the Company demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on customers relative to the original proposal for the CPCN) (Cost Cap Exceptions). The current cost estimate for the Kemper IGCC in total is approximately $6.99 billion, which includes approximately $5.64 billion of costs subject to the construction cost cap and is net of the $137 million in additional grants from the DOE received on April 8, 2016 (Additional DOE Grants), which are expected to be used to reduce future rate impacts to customers. The Company does not intend to seek any rate recovery for any related costs that exceed the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions. The Company recorded pre-tax charges to income for revisions to the cost estimate subject to the construction cost cap totaling $348 million ($215 million after tax), $365 million ($226 million after tax), and $868 million ($536 million after tax) in 2016, 2015, and 2014, respectively. Since 2012, in the aggregate, the Company has incurred charges of $2.76 billion ($1.71 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through December 31, 2016. The current cost estimate includes costs through March 15, 2017.
In addition to the current construction cost estimate, the Company is identifying potential improvement projects that ultimately may be completed subsequent to placing the remainder of the Kemper IGCC in service. If completed, such improvement projects would be expected to enhance plant performance, safety, and/or operations. As of December 31, 2016, approximately $12 million of related potential costs has been included in the estimated loss on the Kemper IGCC. Other projects have yet to be fully evaluated, have not been included in the current cost estimate, and may be subject to the $2.88 billion cost cap. Any further changes in the estimated costs of the Kemper IGCC subject to the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions, will be reflected in the Company's statements of income and these changes could be material.
The expected completion date of the Kemper IGCC at the time of the Mississippi PSC's approval in 2010 was May 2014. The combined cycle and the associated common facilities portion of the Kemper IGCC were placed in service in August 2014. The remainder of the plant, including the gasifiers and the gas clean-up facilities, represents first-of-a-kind technology. The initial production of syngas began on July 14, 2016 for gasifier "B" and on September 13, 2016 for gasifier "A." The Company achieved integrated operation of both gasifiers on January 29, 2017, including the production of electricity from syngas in both combustion turbines. The Company subsequently completed a brief outage to repair and make modifications to further improve the plant's ability to achieve sustained operations sufficient to support placing the plant in service for customers. Efforts to reach sustained operation of both gasifiers and production of electricity from syngas in both combustion turbines are in process. The plant has produced

and captured CO_2, and has produced sulfuric acid and ammonia, all of acceptable quality under the related off-take agreements. On February 20, 2017, the Company determined gasifier "B," which has been producing syngas over 60% of the time since early November 2016, requires an outage to remove ash deposits from its ash removal system. Gasifier "A" and combustion turbine "A" are expected to remain in operation, producing electricity from syngas, as well as producing chemical by-products. As a result, the Company currently expects the remainder of the Kemper IGCC, including both gasifiers, will be placed in service by mid-March 2017.

Upon placing the remainder of the plant in service, the Company will be primarily focused on completing the regulatory cost recovery process. In December 2015, the Mississippi PSC issued an order (In-Service Asset Rate Order), based on a stipulation

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Mississippi Power Company 2016 Annual Report

(2015 Stipulation) between the Company and the MPUS, authorizing rates that provide for the recovery of approximately $126 million annually related to Kemper IGCC assets previously placed in service.

On August 17, 2016, the Mississippi PSC established a discovery docket to manage all filings related to Kemper IGCC prudence issues. On October 3, 2016 and November 17, 2016, the Company made filings in this docket including a review and explanation of differences between the Kemper IGCC project estimate set forth in the 2010 CPCN proceedings and the most recent Kemper IGCC project estimate, as well as comparisons of current cost estimates and current expected plant operational parameters to the estimates presented in the 2010 CPCN proceedings for the first five years after the Kemper IGCC is placed in service. Compared to amounts presented in the 2010 CPCN proceedings, operations and maintenance expenses have increased an average of $105 million annually and maintenance capital has increased an average of $44 million annually for the first full five years of operations for the Kemper IGCC. Additionally, while the current estimated operational availability estimates reflect ultimate results similar to those presented in the 2010 CPCN proceedings, the ramp up period for the current estimates reflects a lower starting point and a slower escalation rate.

In the fourth quarter 2016, as a part of the Integrated Resource Plan process, the Southern Company system completed its regular annual updated fuel forecast, the 2017 Annual Fuel Forecast. This updated fuel forecast reflected significantly lower long-term estimated costs for natural gas than were previously projected. As a result of the updated long-term natural gas forecast, as well as the revised operating expense projections reflected in the discovery docket filings, on February 21, 2017, the Company filed an updated project economic viability analysis of the Kemper IGCC as required under the 2012 MPSC CPCN Order. The project economic viability analysis measures the life cycle economics of the Kemper IGCC compared to feasible alternatives, natural gas combined cycle generating units, under a variety of scenarios and considering fuel, operating and capital costs, and operating characteristics, as well as federal and state taxes and incentives. The reduction in the projected long-term natural gas prices in the 2017 Annual Fuel Forecast and, to a lesser extent, the increase in the estimated Kemper IGCC operating costs, negatively impact the updated project economic viability analysis.

After the remainder of the plant is placed in service, AFUDC equity of approximately $11 million per month will no longer be recorded in income, and the Company expects to incur approximately $25 million per month in depreciation, taxes, operations and maintenance expenses, interest expense, and regulatory costs in excess of current rates. The Company expects to file a request for authority from the Mississippi PSC and the FERC to defer all Kemper IGCC costs incurred after the in-service date that cannot be capitalized, are not included in current rates, and are not required to be charged against earnings as a result of the $2.88 billion cost cap until such time as the Mississippi PSC completes its review and includes the resulting allowable costs in rates. In the event that the Mississippi PSC does not grant the Company's request for an accounting order, these monthly expenses will be charged to income as incurred and will not be recoverable through rates. The ultimate outcome of this matter cannot now be determined but could have a material impact on the Company's result of operations, financial condition, and liquidity.

The Company is required to file a rate case to address Kemper IGCC cost recovery by June 3, 2017 (2017 Rate Case). Costs incurred through December 31, 2016 totaled $6.73 billion, net of the Initial and Additional DOE Grants. Of this total, $2.76 billion of costs has been recognized through income as a result of the $2.88 billion cost cap, $0.83 billion is included in retail and wholesale rates for the assets in service, and the remainder will be the subject of the 2017 Rate Case to be filed with the Mississippi PSC and expected subsequent wholesale MRA rate filing with the FERC. The Company continues to believe that all costs related to the Kemper IGCC have been prudently incurred in accordance with the requirements of the 2012 MPSC CPCN Order. The Company also recognizes significant areas of potential challenge during future regulatory proceedings (and any subsequent, related legal challenges) exist. As described further herein, these challenges include, but are not limited to, prudence issues associated with capital costs, financing costs (AFUDC), and future operating costs, net of chemical revenues; potential operating parameters; income tax issues; costs deferred as regulatory assets; and the 15% portion of the project previously contracted to SMEPA.

Although the 2017 Rate Case has not yet been filed and is subject to future developments with either the Kemper IGCC or the Mississippi PSC, consistent with its approach in the 2013 and 2015 rate proceedings in accordance with the law passed in 2013 authorizing multi-year rate plans, the Company is developing both a traditional rate case requesting full cost recovery of the $3.31 billion (net of $137 million in Additional DOE Grants) not currently in rates and a rate mitigation plan that together represent the Company's probable filing strategy. The Company also expects that timely resolution of the 2017 Rate Case will likely require a negotiated settlement agreement. In the event an agreement acceptable to both the Company and the MPUS (and other parties) can be negotiated and ultimately approved by the Mississippi PSC, it is reasonably possible that full regulatory recovery of all Kemper IGCC costs will not occur. The impact of such an agreement on the Company's financial statements would depend on the method, amount, and type of cost recovery ultimately excluded. Certain costs, including operating costs, would be recorded to income in the period incurred, while other costs, including investment-related costs, would be charged to income when it is probable they will not be recovered and the amounts can be reasonably estimated. In the event an agreement acceptable to the

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parties cannot be reached, the Company intends to fully litigate its request for full recovery through the Mississippi PSC regulatory process and any subsequent legal challenges.

The Company has evaluated various scenarios in connection with its processes to prepare the 2017 Rate Case and has recognized an additional $80 million charge to income, which is the estimated minimum probable amount of the $3.31 billion of Kemper IGCC costs not currently in rates that would not be recovered under the probable rate mitigation plan to be filed by June 3, 2017. Given the variety of potential scenarios and the uncertainty of the outcome of future regulatory proceedings with the Mississippi PSC (and any subsequent related legal challenges), the ultimate outcome of these matters cannot now be determined but could result in further charges that could have a material impact on the Company's results of operations, financial condition, and liquidity.

Southern Company and the Company are defendants in various lawsuits that allege improper disclosure about the Kemper IGCC. While the Company believes that these lawsuits are without merit, an adverse outcome could have a material impact on the Company's results of operations, financial condition, and liquidity. In addition, the SEC is conducting a formal investigation of Southern Company and the Company concerning the estimated costs and expected in-service date of the Kemper IGCC. Southern Company and the Company believe the investigation is focused primarily on periods subsequent to 2010 and on accounting matters, disclosure controls and procedures, and internal controls over financial reporting associated with the Kemper IGCC. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" and "Other Matters" herein for additional information.

As of December 31, 2016, the Company's current liabilities exceeded current assets by approximately $371 million primarily due to $551 million in promissory notes to Southern Company which mature in December 2017, $35 million in senior notes which mature in November 2017, and $63 million in short-term debt. The Company expects the funds needed to satisfy the promissory notes to Southern Company will exceed amounts available from operating cash flows, lines of credit, and other external sources. Accordingly, the Company intends to satisfy these obligations through loans and/or equity contributions from Southern Company. Specifically, the Company has been informed by Southern Company that, in the event sufficient funds are not available from external sources, Southern Company intends to (i) extend the maturity of the $551 million in promissory notes and (ii) provide Mississippi Power with loans and/or equity contributions sufficient to fund the remaining indebtedness scheduled to mature and other cash needs over the next 12 months. Therefore, the Company's financial statement presentation contemplates continuation of the Company as a going concern as a result of Southern Company's anticipated ongoing financial support of the Company, consistent with the requirements of ASU 2014-15 (as defined herein). See FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" herein and Notes 1 and 6 to the financial statements for additional information.

The Company continues to focus on several key performance indicators, including the construction, start-up, and rate recovery of the Kemper IGCC.

In recognition that the Company's long-term financial success is dependent upon how well it satisfies its customers' needs, the Company's retail base rate mechanism, PEP, includes performance indicators that directly tie customer service indicators to the Company's allowed return. PEP measures the Company's performance on a 10-point scale as a weighted average of results in three areas: average customer price, as compared to prices of other regional utilities (weighted at 40%); service reliability, measured in percentage of time customers had electric service (40%); and customer satisfaction, measured in a survey of residential customers (20%). See Note 3 to the financial statements under "Retail Regulatory Matters – Performance Evaluation Plan" for more information on PEP.

In addition to the PEP performance indicators, the Company focuses on other performance measures, including broader measures of customer satisfaction, plant availability, system reliability, and net income after dividends on preferred 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 in measuring performance.

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

Earnings

The Company's net loss after dividends on preferred stock was $50 million in 2016 compared to $8 million in 2015. The change in 2016 was primarily the result of higher pre-tax charges of $428 million ($264 million after tax) in 2016 compared to pre-tax charges of $365 million ($226 million after tax) in 2015 for estimated losses on the Kemper IGCC. The decrease in net income was partially offset by an increase in retail revenues due to the implementation of rates in September 2015 for certain Kemper IGCC in-service assets, partially offset by a decrease in wholesale revenues. The increase in revenues was partially offset by an

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increase in interest expense in 2016 compared to 2015 due to the termination of an asset purchase agreement between the Company and SMEPA in May 2015 and an increase in operations and maintenance expenses.

The Company's net loss after dividends on preferred stock was $8 million in 2015 compared to $329 million in 2014. The change in 2015 was primarily the result of lower pre-tax charges of $365 million ($226 million after tax) in 2015 compared to pre-tax charges of $868 million ($536 million after tax) in 2014 for revisions of estimated costs expected to be incurred on the Company's construction of the Kemper IGCC above the $2.88 billion cost cap established by the Mississippi PSC, net of the Initial DOE Grants and excluding the Cost Cap Exceptions. The reduction in net loss was also related to an increase in retail base revenues, due to the implementation of rates for certain Kemper IGCC assets placed in service that became effective with the first billing cycle in September (on August 19), and a decrease in interest expense primarily due to the termination of an asset purchase agreement between the Company and SMEPA in May 2015, partially offset by increases in income taxes due to a reduced net loss.

See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

RESULTS OF OPERATIONS

A condensed statement of operations follows:

	Amount	Increase (Decrease) from Prior Year	
	2016	2016	2015
	(in millions)		
Operating revenues	$1,163	$ 25	$ (105)
Fuel	343	(100)	(131)
Purchased power	34	22	(31)
Other operations and maintenance	312	38	3
Depreciation and amortization	132	9	26
Taxes other than income taxes	109	15	15
Estimated loss on Kemper IGCC	428	63	(503)
Total operating expenses	1,358	47	(621)
Operating income	(195)	(22)	516
Allowance for equity funds used during construction	124	14	(26)
Interest expense, net of amounts capitalized	74	67	(38)
Other income (expense), net	(7)	1	6
Income taxes (benefit)	(104)	(32)	213
Net income (loss)	(48)	(42)	321
Dividends on preferred stock	2	—	—
Net loss after dividends on preferred stock	$(50)	$ (42)	$ 321

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Operating Revenues
Operating revenues for 2016 were $1.2 billion, reflecting a $25 million increase from 2015. Details of operating revenues were as follows:

	Amount	
	2016	2015
	(in millions)	
Retail — prior year	$776	$795
Estimated change resulting from —		
Rates and pricing	96	61
Sales decline	(4)	(3)
Weather	8	(1)
Fuel and other cost recovery	(17)	(76)
Retail — current year	859	776
Wholesale revenues —		
Non-affiliates	261	270
Affiliates	26	76
Total wholesale revenues	287	346
Other operating revenues	17	16
Total operating revenues	$1,163	$1,138
Percent change	2.2%	(8.4)%

Total retail revenues for 2016 increased $83 million, or 10.7%, compared to 2015 primarily due to changes in rates and pricing of $96 million partially offset by a net decrease in fuel and other cost recovery of $17 million. Total retail revenues for 2015 decreased $19 million, or 2.4%, compared to 2014 primarily due to a lower fuel cost recovery. This decrease was partially offset by changes in rates and pricing of $61 million.
Revenues associated with changes in rates and pricing increased $96 million in 2016 and $61 million in 2015, primarily due to the implementation of rates for certain Kemper IGCC in-service assets effective in September 2015 and an annual ECO rate increase of $22 million collected from September through December 2016.
See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Compliance Overview" and "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs" for additional information.
See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales and weather.
Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, including the energy component of purchased power costs, and do not affect net income. Recoverable fuel costs include fuel and purchased power expenses reduced by the fuel and emissions portion of wholesale revenues from energy sold to customers outside the Company's service territory. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" herein for additional information.
Wholesale revenues from power sales to non-affiliated utilities, including FERC-regulated MRA sales as well as market-based sales, were as follows:

	2016	2015	2014
	(in millions)		
Capacity and other	$157	$158	$160
Energy	104	112	163
Total non-affiliated	$261	$270	$323

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 electric service territory, and the availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income. In addition, the Company provides service under long-term contracts with rural electric cooperative associations and municipalities located in southeastern Mississippi under cost-based electric tariffs which are subject to regulation by the FERC. The contracts with these wholesale customers represented 19.8% of the Company's total operating revenues in 2016 and are largely subject to rolling 10-year cancellation notices. Historically, these wholesale customers have acted as a group and any changes in contractual relationships for one customer are likely to be followed by the other wholesale customers.

Wholesale revenues from sales to non-affiliates decreased $9 million, or 3.3%, in 2016 compared to 2015 primarily as a result of an $8 million decrease in energy revenues, of which $10 million was associated with lower fuel prices, offset by an increase in KWH sales of $2 million. Wholesale revenues from sales to non-affiliates decreased $53 million, or 16.4%, in 2015 compared to 2014 primarily as a result of a $51 million decrease in energy revenues, of which $13 million was associated with a decrease in KWH sales and $38 million was associated with lower fuel prices.

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

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

Wholesale revenues from sales to affiliates decreased $50 million, or 65.8%, in 2016 compared to 2015 primarily due to a $50 million decrease in energy revenues of which $4 million was associated with lower fuel prices and $46 million was associated with a decrease in KWH sales as a result of lower cost generation available in the Southern Company system. Wholesale revenues from sales to affiliates decreased $31 million, or 29.0%, in 2015 compared to 2014 primarily due to a $31 million decrease in energy revenues of which $28 million was associated with lower fuel prices and $3 million was associated with a decrease in KWH sales.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2016 and the percent change from the prior year were as follows:

	Total KWHs 2016 (in millions)	Total KWH Percent Change 2016	Total KWH Percent Change 2015	Weather-Adjusted Percent Change 2016(*)	Weather-Adjusted Percent Change 2015(*)
Residential	2,051	1.3 %	(4.8)%	(2.4)%	(0.4)%
Commercial	2,842	1.3	(1.9)	(2.2)	(0.4)
Industrial	4,906	(1.0)	0.3	(1.6)	0.8
Other	39	(1.3)	(2.1)	(1.3)	(2.1)
Total retail	9,838	0.1	(1.4)	(1.9)%	0.2 %
Wholesale					
Non-affiliated	3,920	1.7	(8.1)		
Affiliated	1,108	(60.5)	(3.2)		
Total wholesale	5,028	(24.5)	(6.1)		
Total energy sales	14,866	(9.8)%	(3.4)%		

(*) In the first quarter 2015, the Company updated the methodology to estimate the unbilled revenue allocation among customer classes. This change did not have a material impact on net income. The KWH sales variances in the above table reflect an adjustment to the estimated allocation of the Company's unbilled 2014 and first quarter 2015 KWH sales among customer classes that is consistent with the actual allocation in 2015 and 2016, respectively.

Without this adjustment, 2016 weather-adjusted residential sales decreased 1.0%, commercial sales decreased 0.6%, and industrial KWH sales decreased 1.0% as compared to the corresponding period in 2015. Without this adjustment, 2015 weather-adjusted residential sales decreased 1.8%, commercial sales decreased 2.1%, and industrial KWH sales increased 0.3% as compared to the corresponding period in 2014.

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 increased 0.1% in 2016 as compared to the prior year. This increase was primarily the result of warmer weather in the third quarter 2016 as compared to the corresponding period in 2015. Weather-adjusted residential and commercial KWH sales decreased primarily due to decreased customer usage partially offset by customer growth. The decrease in industrial KWH energy sales was primarily due to planned and unplanned outages by large industrial customers.

Retail energy sales decreased 1.4% in 2015 as compared to the prior year. This decrease was primarily the result of milder weather in the first and fourth quarters of 2015 as compared to the corresponding periods in 2014. Weather-adjusted residential and commercial KWH sales decreased primarily due to decreased customer usage partially offset by customer growth. Household income, one of the primary drivers of residential customer usage, had modest growth in 2015. The increase in industrial KWH energy sales was primarily due to expanded operation by many industrial customers.

Wholesale energy sales to non-affiliates decreased in 2016 compared to 2015 primarily due to lower fuel prices which was partially offset by an increased opportunity sales to the external market based on higher demand. Wholesale energy sales to non-affiliates decreased in 2015 compared to 2014 primarily due to decreased opportunity sales to the external market based on lower demand which was offset by lower fuel prices.

Wholesale energy sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company and the Southern Company system's generation, demand for energy within the Southern Company system's electric service territory, and the availability of the Southern Company system's generation.

Wholesale energy sales to affiliates decreased in 2016 compared to 2015 primarily due to lower fuel cost and reduced sales to affiliate companies. Wholesale energy sales to affiliates decreased in 2015 compared to 2014 primarily due to lower fuel cost and reduced sales to affiliate companies.

Fuel and Purchased Power Expenses

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

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

	2016	2015	2014
Total generation (in millions of KWHs)	14,514	17,014	16,881
Total purchased power (in millions of KWHs)	1,574	539	886
Sources of generation (percent) –			
Coal	9	17	42
Gas	91	83	58
Cost of fuel, generated (in cents per net KWH) –			
Coal	3.91	3.71	3.96
Gas	2.41	2.58	3.37
Average cost of fuel, generated (in cents per net KWH)	2.55	2.78	3.64
Average cost of purchased power (in cents per net KWH)	3.07	2.17	4.85

Fuel and purchased power expenses were $377 million in 2016, a decrease of $78 million, or 17.1%, as compared to the prior year. The decrease was primarily due to a $20 million decrease in the cost of natural gas and a decrease of $82 million due to a decrease in the volume of KWH generation, partially offset by a $12 million increase in KWHs purchased and a $12 million increase in the cost of coal. Fuel and purchased power expenses were $455 million in 2015, a decrease of $162 million, or 26.3%, as compared to the prior year. The decrease was primarily due to a $125 million decrease in the cost of fuel and purchased power and a decrease of $183 million in the volume of KWHs generated by coal and purchased, partially offset by a $146 million increase in the volume of KWHs generated by gas.

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 fuel cost recovery clauses. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" herein and Note 1 to the financial statements under "Fuel Costs" for additional information.

Fuel

Fuel expense decreased $100 million, or 22.6%, in 2016 compared to 2015 due to an 8.2% decrease in the average cost of fuel per KWH generated and a 15.5% decrease in the volume of KWHs generated. Fuel expense decreased $131 million, or 22.8%, in

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2015 compared to 2014. The decrease was the result of a 23.6% decrease in the average cost of fuel per KWH generated, partially offset by a 0.9% increase in the volume of KWHs generated.

Purchased Power - Non-Affiliates

Purchased power expense from non-affiliates was flat in 2016 compared to 2015. Purchased power expense from non-affiliates decreased $13 million, or 72.2%, in 2015 compared to 2014. The decrease was primarily the result of a 72.4% decrease in the average cost per KWH purchased.

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

Purchased Power - Affiliates

Purchased power expense from affiliates increased $22 million, or 314.3%, in 2016 compared to 2015. The increase in 2016 was primarily the result of a 338.4% increase in the volume of KWHs purchased due to the availability of lower cost energy as compared to the cost of self-generation and a slight increase in the average cost per KWH purchased compared to 2015. Purchased power expense from affiliates decreased $18 million, or 72.0%, in 2015 compared to 2014. The decrease in 2015 was primarily the result of a 58.3% decrease in the volume of KWHs purchased and a 36.9% decrease in the average cost per KWH purchased compared to 2014.

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

Other operations and maintenance expenses increased $38 million, or 13.9%, in 2016 compared to the prior year. The increase was primarily due to a $28 million increase in operations and maintenance expenses related to the combined cycle and the associated common facilities portion of the Kemper IGCC, $10 million in amortization of prior operations and maintenance expense deferrals that the Company began recognizing in connection with rates associated with the Kemper IGCC in-service assets, and a $7 million increase in transmission and distribution expenses primarily related to overhead line maintenance and vegetation management, partially offset by a $9 million decrease in generation outage costs.

Other operations and maintenance expenses increased $3 million, or 1.1%, in 2015 compared to the prior year. The increase was primarily related to a $7 million increase in employee compensation and benefits, including pension costs, and a $6 million increase in generation maintenance expenses related to the combined cycle and the associated common facilities portion of the Kemper IGCC. See Note 2 to the financial statements for additional information on pension costs. Beginning in the third quarter 2015, in connection with the implementation of rates associated with the Kemper IGCC, the Company began expensing certain ongoing project costs associated with Kemper IGCC assets placed in service that previously were deferred as regulatory assets. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – 2015 Rate Case" and " – Regulatory Assets and Liabilities" herein for additional information. These increases in 2015 were partially offset by decreases of $4 million in transmission and distribution expenses primarily related to overhead line maintenance and vegetation management, $3 million in generation maintenance expenses primarily due to lower outage costs, and $2 million in overtime labor.

Depreciation and Amortization

Depreciation and amortization increased $9 million, or 7.3%, in 2016 compared to 2015 primarily due to $32 million of additional regulatory asset amortization related to the In-Service Asset Rate Order, ECO plan, and Mercury and Air Toxics Standards (MATS) rule compliance, $13 million associated with Kemper IGCC deferrals primarily related to depreciation deferrals in 2015, and $9 million of depreciation for additional plant in service assets primarily associated with the Plant Daniel scrubbers. These increases were partially offset by $23 million of amortization of regulatory deferrals related to the In-Service Asset Rate Order and a $22 million deferral associated with the implementation of revised ECO plan rates with the first billing cycle for September 2016.

Depreciation and amortization increased $26 million, or 26.8%, in 2015 compared to 2014 primarily due to an $18 million increase in depreciation related to an increase in assets in service and an increase in the depreciation rates, a $16 million increase due to amortization of regulatory assets associated with the Kemper IGCC, and a $2 million increase resulting from the estimated 2015 cost of capital as agreed in the In-Service Asset Rate Order. These increases were partially offset by decreases of $5 million

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in ECO plan amortization, $3 million in Kemper IGCC combined cycle cost deferrals, and $2 million in deferrals associated with the purchase of Plant Daniel Units 3 and 4. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – Regulatory Assets and Liabilities" herein for additional information.

See Note 1 to the financial statements under "Depreciation and Amortization" and Note 3 to the financial statements under "FERC Matters," "Retail Regulatory Matters – Environmental Compliance Overview Plan," and "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $15 million, or 16.0%, in 2016 compared to 2015 primarily due to increases in ad valorem taxes of $10 million, related to an increase in the assessed value of property, as well as increases in franchise taxes of $5 million, related to increased operating revenue. Taxes other than income taxes increased $15 million, or 19.0%, in 2015 compared to 2014 primarily as a result of a $12 million increase in ad valorem taxes and a $4 million increase in franchise taxes, partially offset by a $1 million decrease in payroll taxes.

The retail portion of ad valorem taxes is recoverable under the Company's ad valorem tax cost recovery clause and, therefore, does not affect net income.

Estimated Loss on Kemper IGCC

Estimated probable losses on the Kemper IGCC of $428 million, $365 million, and $868 million were recorded in 2016, 2015, and 2014, respectively, to reflect revisions of estimated costs expected to be incurred on the construction of the Kemper IGCC in excess of the $2.88 billion cost cap established by the Mississippi PSC, net of the Initial DOE Grants and excluding the Cost Cap Exceptions. The 2016 loss also reflects $80 million associated with the estimated minimum probable amount of costs not currently in rates that would not be recovered under the probable rate mitigation plan to be filed by June 3, 2017.

See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

Allowance for Equity Funds Used During Construction

AFUDC equity increased $14 million, or 12.7%, in 2016 as compared to 2015. The increase in 2016 was primarily due to a higher AFUDC rate and an increase in Kemper IGCC CWIP subject to AFUDC, partially offset by placing the Plant Daniel scrubbers in service in November 2015. AFUDC equity decreased $26 million, or 19.1%, in 2015 as compared to 2014. The decrease in 2015 was primarily due to a reduction in the AFUDC rate driven by an increase in short-term borrowings and placing the combined cycle and the associated common facilities portion of the Kemper IGCC in service in August 2014. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Allowance for Funds Used During Construction" herein and Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized increased $67 million in 2016 compared to 2015. The increase was primarily due to an increase of $31 million of interest on deposits resulting from the 2015 reversal of interest associated with the termination of an asset purchase agreement between the Company and SMEPA in May 2015; a $20 million increase due to additional long-term debt and a $30 million decrease in amounts capitalized primarily resulting from $17 million of capitalized interest and the amortization of $13 million in interest deferrals in accordance with the In-Service Asset Rate Order. These net increases were partially offset by a decrease of $16 million in interest accrued on the Mirror CWIP liability prior to refund in 2015.

Interest expense, net of amounts capitalized decreased $38 million, or 84.4%, in 2015 compared to 2014. The decrease was primarily due to a $58 million decrease related to the termination of an asset purchase agreement between the Company and SMEPA in May 2015 which required the return of SMEPA's deposits at a lower rate of interest than accrued, a $5 million decrease associated with amended tax returns, and a $2 million decrease associated with the redemption of long-term debt in 2015. These decreases were partially offset by increases in interest expense of $10 million associated with additional issuances of debt in 2015, $9 million associated with unrecognized tax benefits, and $5 million related to the Mirror CWIP refund, partially offset by a $3 million decrease in AFUDC debt. See Note 5 to the financial statements for additional information.

See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle – Termination of Proposed Sale of Undivided Interest to SMEPA" for more information.

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Income Taxes (Benefit)
Income tax benefits increased $32 million, or 44.4%, in 2016 compared to 2015 primarily as a result of an increase in the estimated probable losses on the Kemper IGCC and an increase in AFUDC equity, which is non-taxable.
Income tax benefits decreased $213 million, or 74.7%, in 2015 compared to 2014 primarily resulting from the reduction in pre-tax losses related to the estimated probable losses on the Kemper IGCC.
Effects of Inflation
The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.
FUTURE EARNINGS POTENTIAL
General
The Company operates as a vertically integrated utility providing electric service to retail customers within its traditional service territory located in southeast Mississippi and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Mississippi PSC under cost-based regulatory principles. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. See "FERC Matters" herein, ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Utility Regulation" herein, and Note 3 to the financial statements for additional information about regulatory matters.
The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to recover its prudently-incurred costs, including those related to the remainder of the Kemper IGCC costs not included in current rates, in a timely manner during a time of increasing costs, its ability to prevail against legal challenges associated with the Kemper IGCC, and the completion and subsequent operation of the Kemper IGCC in accordance with any operational parameters that may be adopted by the Mississippi PSC. Future earnings will be driven primarily by customer growth. Earnings will also depend upon maintaining and growing sales, considering, among other things, the adoption and/or penetration rates of increasingly energy-efficient technologies and increasing volumes of electronic commerce transactions. Earnings are subject to a variety of other factors. These factors include weather, competition, developing new and maintaining existing energy contracts and associated load requirements with other utilities and other wholesale customers, 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 primarily 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. Current proposals related to potential tax reform legislation are primarily focused on reducing the corporate income tax rate, allowing 100% of capital expenditures to be deducted, and eliminating the interest deduction. The ultimate impact of any tax reform proposals is dependent on the final form of any legislation enacted and the related transition rules and cannot be determined at this time, but could have a material impact on the Company's financial statements.
The Company provides service under long-term contracts with rural electric cooperative associations and municipalities located in southeastern Mississippi under cost-based electric tariffs which are subject to regulation by the FERC. The contracts with these wholesale customers represented 19.8% of the Company's total operating revenues in 2016 and are largely subject to rolling 10-year cancellation notices. Historically, these wholesale customers have acted as a group and any changes in contractual relationships for one customer are likely to be followed by the other wholesale customers.

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 or through long-term wholesale agreements. 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. 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.

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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 2016, the Company had invested approximately $634 million in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $17 million, $94 million, and $118 million for 2016, 2015, and 2014, respectively. The Company expects that capital expenditures to comply with environmental statutes and regulations will total approximately $127 million from 2017 through 2021, with annual totals of approximately $11 million, $5 million, $24 million, $29 million, and $58 million for 2017, 2018, 2019, 2020, and 2021, respectively. These estimated expenditures do not include any potential capital expenditures that may arise from the EPA's final rules and guidelines or future state plans that would limit CO_2 emissions from existing, new, modified, or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" herein for additional information. The Company also anticipates costs associated with ash pond closure and ground water monitoring under the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), which are reflected in the Company's ARO liabilities. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" 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 time periods over which compliance with regulations is required; individual state implementation of regulations, as applicable; the outcome of any legal challenges to the environmental rules; any additional rulemaking activities in response to legal challenges and court decisions; the cost, availability, and existing inventory of emissions allowances; the impact of future changes in generation and emissions-related technology; the Company's fuel mix; and environmental remediation requirements. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, 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 Compliance Overview Plan" herein for additional information.
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.
In 2012, the EPA finalized the 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 implementation strategy for the MATS rule included emission controls, retirements, and fuel conversions at affected units. All of the Company's units that are subject to the MATS rule completed the measures necessary to achieve compliance with this rule or were

retired prior to or during 2016.
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. In October 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 were required to recommend area designations by October 2016, and no areas within the Company's service territory were proposed for designation as nonattainment.
The EPA regulates fine particulate matter concentrations through an annual and 24-hour average NAAQS, based on standards promulgated in 1997, 2006, and 2012. All areas in which the Company's generating units are located have been determined by the EPA to be in attainment with those standards.

In 2010, the EPA revised the NAAQS for sulfur dioxide (SO_2), establishing a new one-hour standard. No areas within the Company's service territory have been designated as nonattainment under this standard. However, in 2015, the EPA finalized a data requirements rule to support final EPA designation decisions for all remaining areas under the SO_2 standard, which could result in nonattainment designations for areas within the Company's service territory. Nonattainment designations could require additional reductions in SO_2 emissions and increased compliance and operational costs.

On July 6, 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide (NO_x) emissions from power plants in two phases – Phase 1 in 2015 and Phase 2 in 2017. On October 26, 2016, the EPA published a final rule that updates the CSAPR ozone season NO_x program, beginning in 2017, and establishes more stringent ozone-season emissions budgets in Alabama and Mississippi. The State of Alabama is also in the CSAPR annual SO_2 and NO_x programs.

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. On December 14, 2016, the EPA finalized revisions to the regional haze regulations. These regulations establish a deadline of July 31, 2021 for states to submit revised SIPs to the EPA demonstrating reasonable progress toward the statutory goal of achieving natural background conditions by 2064. State implementation of the reasonable progress requirements defined in this final rule could require further reductions in SO_2 or NO_x emissions.

In June 2015, the EPA published a final rule requiring certain states (including Alabama and Mississippi) 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), and many states have submitted proposed SIP revisions in response to the rule.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the current and proposed environmental requirements discussed above. 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. The ultimate impact of the eight-hour ozone and SO_2 NAAQS, CSAPR, regional haze regulations, and SSM rule will depend on various factors, such as implementation, adoption, or other action at the state level, and the outcome of pending and/or future legal challenges, and cannot be determined at this time.

See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Compliance Overview Plan" for additional information.

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 2014. The effect of this final rule will depend on the results of additional studies that are currently underway and implementation of the rule by regulators based on site-specific factors. National Pollutant Discharge Elimination System (NPDES) permits issued after July 14, 2018 must include conditions to implement and ensure compliance with the standards and protective measures required by the rule.

In November 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 NPDES 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.
In 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 in August 2015 but, in October 2015, the U.S. Court of Appeals for the Sixth Circuit issued an order staying implementation of the final rule. The case is held in abeyance pending review by the U.S. Supreme Court of challenges to the U.S. Court of Appeals for the Sixth Circuit's jurisdiction in the case.

These water quality regulations could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions and decisions on infrastructure expansion and improvements. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. The ultimate impact of these final rules will depend on various factors, such as pending and/or future legal challenges, compliance dates, and implementation of the rules, and cannot be determined at this time.

Coal Combustion Residuals

The Company currently manages two electric generating plants in Mississippi and is also part owner of a plant located in Alabama, each with onsite CCR storage units consisting of landfills and surface impoundments (CCR Units). 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 States of Mississippi and Alabama each have their own regulatory requirements. The Company has an inspection program in place to assist in maintaining the integrity of its coal ash surface impoundments.

The CCR Rule became effective in October 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. On December 16, 2016, President Obama signed the Water Infrastructure Improvements for the Nation Act (WIIN Act). The WIIN Act allows states to establish permit programs for implementing the CCR Rule, if the EPA approves the program, and allows for federal permits and EPA enforcement where a state permitting program does not exist.

Based on current cost estimates for closure and monitoring of ash ponds pursuant to the CCR Rule, the Company has 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 with respect to compliance activities, the Company expects to continue to periodically update these estimates. The Company has posted closure and post-closure care plans to its public website as required by the CCR Rule; however, the ultimate impact of the CCR Rule will depend on the results of initial and ongoing minimum criteria assessments and the implementation of state or federal permit programs. On December 15, 2016, the Mississippi PSC granted a CPCN to the Company authorizing certain projects associated with complying with the CCR Rule. Additionally in this order, the Mississippi PSC also authorized the Company to recover any costs associated with the CPCN, including future monitoring costs, through the ECO plan rate. 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, 2016.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company 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 impacted sites. The Company has authority from the Mississippi PSC to recover approved environmental compliance costs through its ECO clause. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Global Climate Issues

In October 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 review with the courts. The stay will remain in effect through the resolution of the litigation, including any review by 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 and decisions on infrastructure expansion and improvements. 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 outcome of pending legal challenges, including legal challenges filed by the traditional electric operating companies, and any individual state implementation of the EPA's final guidelines in the event the rule is upheld and implemented.

In December 2015, parties to the United Nations Framework Convention on Climate Change – including the United States – adopted 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 tracking progress toward the goals every five years. The ultimate impact of this agreement depends on its implementation by participating countries and cannot be determined at this time.

The EPA's greenhouse gas reporting rule requires annual reporting of greenhouse gas emissions expressed in terms of metric tons of CO_2 equivalent emissions for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2015 greenhouse gas emissions were approximately 7 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2016 greenhouse gas emissions on the same basis is approximately 7 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

Municipal and Rural Associations Tariff

In 2013, the FERC accepted a settlement agreement entered into by the Company with its wholesale customers which approved, among other things, the same regulatory treatment for tariff ratemaking as the treatment approved for retail ratemaking by the Mississippi PSC for certain items. The regulatory treatment includes (i) approval to establish a regulatory asset for the portion of non-capitalizable Kemper IGCC-related costs which have been and will continue to be incurred during the construction period for the Kemper IGCC, (ii) authorization to defer as a regulatory asset, for the 10-year period ending October 2021, the difference between the revenue requirement under the purchase option of Plant Daniel Units 3 and 4 (assuming a remaining 30-year life) and the revenue requirement assuming the continuation of the operating lease regulatory treatment with the accumulated deferred balance at the end of the deferral being amortized into wholesale rates over the remaining life of Plant Daniel Units 3 and 4, and (iii) authority to defer in a regulatory asset costs related to the retirement or partial retirement of generating units as a result of environmental compliance rules.

In 2014, the Company reached, and the FERC accepted, a settlement agreement with its wholesale customers for an estimated annual increase in the MRA cost-based tariff of approximately $10 million, effective May 1, 2014. Included in this settlement agreement was a mechanism allowing the Company to adjust the wholesale revenue requirement in a subsequent rate proceeding in the event the Kemper IGCC, or any substantial portion thereof, was placed in service before or after December 1, 2014. Therefore, the Company recorded a regulatory asset as a result of a portion of the Kemper IGCC being placed in service prior to the projected date, which was fully amortized as of December 31, 2015.

In May 2015, the FERC accepted a further settlement agreement between the Company and its wholesale customers to forgo a MRA cost-based electric tariff increase by, among other things, increasing the accrual of AFUDC and lowering the portion of CWIP in rate base, effective April 1, 2015, resulting in an estimated annual AFUDC increase of approximately $14 million, of which approximately $11 million is related to the Kemper IGCC.

On March 31, 2016, the Company reached a settlement agreement with its wholesale customers, which was subsequently approved by the FERC, for an increase in wholesale base revenues under the MRA cost-based electric tariff, primarily as a result of placing scrubbers for Plant Daniel Units 1 and 2 in service in November 2015. The settlement agreement became effective for services rendered beginning May 1, 2016, resulting in an estimated annual revenue increase of $7 million under the MRA cost-based electric tariff. Additionally, under the settlement agreement, the tariff customers agreed to similar regulatory treatment for MRA tariff ratemaking as the treatment approved for retail ratemaking under the In-Service Asset Rate Order. This regulatory treatment primarily includes (i) recovery of the Kemper IGCC assets currently operational and providing service to customers and other related costs, (ii) amortization of the Kemper IGCC-related regulatory assets included in rates under the settlement agreement over the 36 months ending April 30, 2019, (iii) Kemper IGCC-related expenses included in rates under the settlement agreement no longer being deferred and charged to expense, and (iv) removing all of the Kemper IGCC CWIP from rate base with a corresponding increase in accrual of AFUDC. The additional resulting AFUDC is estimated to be approximately $14 million through the Kemper IGCC's projected in-service date of mid-March 2017.

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Fuel Cost Recovery

The Company has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. Effective with the first billing cycle for September 2016, fuel rates decreased $11 million annually for wholesale MRA customers and $1 million annually for wholesale MB customers. At December 31, 2016 and 2015, the amount of over recovered wholesale MRA fuel costs were approximately $13 million and $24 million, respectively, which is included in over recovered regulatory clause liabilities, current in the balance sheets. Effective January 1, 2017, the wholesale MRA fuel rate increased $10 million annually.

The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, changes in the billing factor should have no significant effect on the Company's revenues or net income, but will affect cash flow.

Market-Based Rate Authority

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 electric operating companies (including the Company) and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In April 2015, the FERC issued an order finding that the traditional electric 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 electric operating companies and in some adjacent areas. The FERC directed the traditional electric 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 electric operating companies (including the Company) and Southern Power filed a request for rehearing in May 2015 and in June 2015 filed their response with the FERC.

On December 9, 2016, the traditional electric operating companies (including the Company) and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' (including the Company's) and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies (including the Company) and in some adjacent areas. The traditional electric operating companies (including the Company) and Southern Power expect to make a compliance filing within 30 days accepting the terms of the order. While the FERC's February 2, 2017 order references the market power proceeding discussed above, it remains a separate, ongoing matter.

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

Retail Regulatory Matters

General

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Mississippi PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased power, energy efficiency programs, ad valorem taxes, property damage, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates. See Note 3 to the financial statements under "Retail Regulatory Matters" and "Integrated Coal Gasification Combined Cycle" for additional information.

In 2012, the Mississippi PSC issued an order for the purpose of investigating and reviewing, for informational purposes only, the ROE formulas used by the Company and all other regulated electric utilities in Mississippi. In 2013, the MPUS filed with the Mississippi PSC its report on the ROE formulas used by the Company and all other

regulated electric utilities in Mississippi. The ultimate outcome of this matter cannot be determined at this time.
Renewables
In November 2015, the Mississippi PSC issued orders approving three solar facilities for a combined total of approximately 105 MWs. The Company will purchase all of the energy produced by the solar facilities for the 25-year term under each of the three PPAs. The projects are expected to be in service by the second quarter 2017 and the resulting energy purchases are expected to be recovered through the Company's fuel cost recovery mechanism. The Company may retire the renewable energy credits (REC) generated on behalf of its customers or sell the RECs, separately or bundled with energy, to third parties.

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Performance Evaluation Plan
The Company's retail base rates are set under the PEP, a rate plan approved by the Mississippi PSC. Two filings are made for each calendar year: the PEP projected filing, which is typically filed prior to the beginning of the year based on a projected revenue requirement, and the PEP lookback filing, which is filed after the end of the year and allows for review of the actual revenue requirement compared to the projected filing.
In 2011, the Company submitted its annual PEP lookback filing for 2010, which recommended no surcharge or refund. Later in 2011, the Company received a letter from the MPUS disputing certain items in the 2010 PEP lookback filing. In 2012, the Mississippi PSC issued an order canceling the Company's PEP lookback filing for 2011. In 2013, the MPUS contested the Company's PEP lookback filing for 2012, which indicated a refund due to customers of $5 million. Unresolved matters related to the 2010 PEP lookback filing, which remain under review, also impact the 2012 PEP lookback filing.
In 2013, the Mississippi PSC approved the projected PEP filing for 2013, which resulted in a rate increase of 1.9%, or $15 million, annually, effective March 19, 2013. The Company may be entitled to $3 million in additional revenues related to 2013 as a result of the late implementation of the 2013 PEP rate increase.
In 2014, 2015, and 2016, the Company submitted its annual PEP lookback filings for the prior years, which for 2013 and 2014 each indicated no surcharge or refund and for 2015 indicated a $5 million surcharge. On July 12, 2016 and November 15, 2016, the Company submitted its annual projected PEP filings for 2016 and 2017, respectively, which each indicated no change in rates. The Mississippi PSC suspended each of these filings to allow more time for review.
In 2014, the Mississippi PSC issued an order for the purpose of investigating and reviewing the adoption of a uniform formula rate plan for the Company and other regulated electric utilities in Mississippi.
The ultimate outcome of these matters cannot be determined at this time.
Energy Efficiency
In 2013, the Mississippi PSC approved an energy efficiency and conservation rule requiring electric and gas utilities in Mississippi serving more than 25,000 customers to implement energy efficiency programs and standards.
On May 3, 2016, the Mississippi PSC issued an order approving the Company's Energy Efficiency Cost Rider Compliance filing, which reduced annual retail revenues by approximately $2 million effective with the first billing cycle for June 2016.
On November 30, 2016, the Company submitted its Energy Efficiency Cost Rider Compliance filing, which included an increase of $1 million in annual retail revenues. The ultimate outcome of this matter cannot be determined at this time.
See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.
Environmental Compliance Overview Plan
In 2012, the Mississippi PSC approved the Company's request for a CPCN to construct scrubbers on Plant Daniel Units 1 and 2, which were placed in service in November 2015. These units are jointly owned by the Company and Gulf Power, with 50% ownership each. In 2014, the Company entered into a settlement agreement with the Sierra Club that, among other things, required the Sierra Club to dismiss or withdraw all pending legal and regulatory challenges to the issuance of the CPCN to construct scrubbers on Plant Daniel Units 1 and 2, which also occurred in 2014. In addition, and consistent with the Company's ongoing evaluation of recent environmental rules and regulations, the Company agreed to retire, repower with natural gas, or convert to an alternative non-fossil fuel source Plant Sweatt Units 1 and 2 (80 MWs) no later than December 2018 (and the units were retired in July 2016). The Company also agreed that it would cease burning coal and other solid fuel at Plant Watson Units 4 and 5 (750 MWs) and begin operating those units solely on natural gas no later than April 2015 (which occurred in April 2015) and cease burning coal and other solid fuel at Plant Greene County Units 1 and 2 (200 MWs) no later than April 2016 (which occurred in February and March 2016, respectively) and begin operating those units solely on natural gas (which occurred in June and July 2016, respectively).

In accordance with a 2011 accounting order from the Mississippi PSC, the Company has the authority to defer in a regulatory asset for future recovery all plant retirement- or partial retirement-related costs resulting from environmental regulations. As of December 31, 2016, $17 million of Plant Greene County costs have been reclassified as regulatory assets and are expected to be recovered through the ECO plan and other existing cost recovery mechanisms over a period to be determined by the Mississippi PSC. The Mississippi PSC approved $41 million of costs that were reclassified to a regulatory asset associated with Plant Watson for amortization over a five-year period that began in July 2016. As a result, these decisions are not expected to have a material impact on the Company's financial statements.

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On August 17, 2016, the Mississippi PSC approved the Company's revised ECO plan filing for 2016, which requested the maximum 2% annual increase in revenues, approximately $18 million, primarily related to the Plant Daniel Units 1 and 2 scrubbers being placed in service in November 2015. The revised rates became effective with the first billing cycle for September 2016. Approximately $22 million of related revenue requirements in excess of the 2% maximum was deferred for inclusion in the 2017 filing.

On February 14, 2017, the Company submitted its ECO plan filing for 2017, which requested an increase in annual revenues over 2016, capped at 2% of total retail revenues, of approximately $18 million, primarily related to the Plant Daniel Units 1 and 2 scrubbers placed in service in November 2015. The revenue requirement in excess of the 2%, approximately $27 million plus carrying costs, will be carried forward to the 2018 filing. The ultimate outcome of this matter cannot be determined at this time.

Fuel Cost Recovery

The Company establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. The Company is required to file for an adjustment to the retail fuel cost recovery factor annually. The Mississippi PSC approved the 2016 retail fuel cost recovery factor, effective January 5, 2016, which resulted in an annual revenue decrease of approximately $120 million. On August 17, 2016, the Mississippi PSC approved an additional decrease of $51 million annually in fuel cost recovery rates effective with the first billing cycle for September 2016. At December 31, 2016 and 2015, over recovered retail fuel costs were approximately $37 million and $71 million, respectively, which is included in over recovered regulatory clause liabilities, current in the balance sheets. On January 12, 2017, the Mississippi PSC approved the 2017 retail fuel cost recovery factor, effective February 2017 through January 2018, which will result in an annual revenue increase of approximately $55 million.

The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, changes in the billing factor should have no significant effect on the Company's revenues or net income, but will affect cash flow.

Ad Valorem Tax Adjustment

The Company establishes, annually, an ad valorem tax adjustment factor that is approved by the Mississippi PSC to collect the ad valorem taxes paid by the Company. On June 17, 2016, the Mississippi PSC approved the Company's annual ad valorem tax adjustment factor filing for 2016, which included an annual rate decrease of 0.07%, or $1 million in annual retail revenues, primarily due to the prior year over recovery.

System Restoration Rider

In October 2015, the Mississippi PSC approved the Company's 2015 SRR rate filing, which proposed that the SRR rate remain level at zero and the Company continue to accrue $3 million annually to the property damage reserve.

On February 1, 2016, the Company submitted its 2016 SRR rate filing which proposed no changes to either the SRR rate or the annual property damage reserve accrual. On February 19, 2016, the filing was suspended by the Mississippi PSC for review. The ultimate outcome of this matter cannot be determined at this time.

On February 3, 2017, the Company submitted its 2017 SRR rate filing, which proposed that the rate level remain at zero and the Company be allowed to accrue $4 million annually to the property damage reserve in 2017. The ultimate outcome of this matter cannot be determined at this time.

See Note 1 to the financial statements under "Provision for Property Damage" for additional information.

Storm Damage Cost Recovery

In connection with the damage associated with Hurricane Katrina, the Mississippi PSC authorized the issuance of system restoration bonds in 2006. In accordance with a Mississippi PSC order dated January 24, 2017, the Company has adjusted the System Restoration Charge implemented after Hurricane Katrina to zero. Upon completion of the proper defeasance process by the Mississippi State Bond Commission, the Company's obligations in relation to system restoration bonds issued after Hurricane Katrina in 2005 will be completely satisfied.

Provision for Property Damage

On January 21, 2017, a tornado caused extensive damage to the Company's transmission and distribution infrastructure. Preliminary storm damage repairs have been estimated at $11 million. A portion of these costs may be charged to the retail property damage reserve and addressed in a subsequent SRR rate filing. The ultimate outcome of this matter cannot be determined at this time.

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Integrated Coal Gasification Combined Cycle
Kemper IGCC Overview
The Kemper IGCC utilizes IGCC technology with an expected output capacity of 582 MWs. The Kemper IGCC is fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by the Company and situated adjacent to the Kemper IGCC. The mine, operated by North American Coal Corporation, started commercial operation in 2013. In connection with the Kemper IGCC, the Company constructed and plans to operate approximately 61 miles of CO_2 pipeline infrastructure for the transport of captured CO_2 for use in enhanced oil recovery.
Kemper IGCC Schedule and Cost Estimate
In 2012, the Mississippi PSC issued the 2012 MPSC CPCN Order, a detailed order confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing the acquisition, construction, and operation of the Kemper IGCC. The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC CPCN Order was $2.4 billion, net of $245 million of Initial DOE Grants and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and AFUDC related to the Kemper IGCC. The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion, with recovery of prudently-incurred costs subject to approval by the Mississippi PSC. The Kemper IGCC was originally projected to be placed in service in May 2014. The Company placed the combined cycle and the associated common facilities portion of the Kemper IGCC in service in August 2014. The remainder of the plant, including the gasifiers and the gas clean-up facilities, represents first-of-a-kind technology. The initial production of syngas began on July 14, 2016 for gasifier "B" and on September 13, 2016 for gasifier "A." The Company achieved integrated operation of both gasifiers on January 29, 2017, including the production of electricity from syngas in both combustion turbines. The Company subsequently completed a brief outage to repair and make modifications to further improve the plant's ability to achieve sustained operations sufficient to support placing the plant in service for customers. Efforts to reach sustained operation of both gasifiers and production of electricity from syngas in both combustion turbines are in process. The plant has produced and captured CO_2, and has produced sulfuric acid and ammonia, all of acceptable quality under the related off-take agreements. On February 20, 2017, the Company determined gasifier "B," which has been producing syngas over 60% of the time since early November 2016, requires an outage to remove ash deposits from its ash removal system. Gasifier "A" and combustion turbine "A" are expected to remain in operation, producing electricity from syngas, as well as producing chemical by-products. As a result, the Company currently expects the remainder of the Kemper IGCC, including both gasifiers, will be placed in service by mid-March 2017.
The Company's Kemper IGCC 2010 project estimate, current cost estimate (which includes the impacts of the Mississippi Supreme Court's (Court) decision discussed herein under "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order"), and actual costs incurred as of December 31, 2016, all of which include 100% of the costs for the Kemper IGCC, are as follows:

Cost Category	2010 Project Estimate[a]	Current Cost Estimate[b]	Actual Costs
	(in billions)		
Plant Subject to Cost Cap[c][e]	$2.40	$ 5.64	$5.44
Lignite Mine and Equipment	0.21	0.23	0.23
CO_2 Pipeline Facilities	0.14	0.11	0.11
AFUDC[d]	0.17	0.79	0.75
Combined Cycle and Related Assets Placed in Service – Incremental[f]	—	0.04	0.04
General Exceptions	0.05	0.10	0.09
Deferred Costs[e]	—	0.22	0.21

Additional DOE Grants	—	(0.14)	(0.14)
Total Kemper IGCC[f]	$2.97	$ 6.99	$6.73

(a) The 2010 Project Estimate is the certificated cost estimate adjusted to include the certificated estimate for the CO_2 pipeline facilities approved in 2011 by the Mississippi PSC, as well as the lignite mine and equipment, AFUDC, and general exceptions.

(b) Amounts in the Current Cost Estimate include certain estimated post-in-service costs which are expected to be subject to the cost cap.

(c) The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion, net of the Initial DOE Grants and excluding the Cost Cap Exceptions. The Current Cost Estimate and the Actual Costs include non-incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service in August 2014 that are subject to the $2.88 billion cost cap and exclude post-in-service costs for the lignite mine. See "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" herein for additional information.

(d) The Company's 2010 Project Estimate included recovery of financing costs during construction rather than the accrual of AFUDC. This approach was not approved by the Mississippi PSC as described in "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order." The Current Cost Estimate also reflects the impact of a settlement agreement with the wholesale customers for cost-based rates under FERC's jurisdiction. See "FERC Matters" herein for additional information.

(e) Non-capital Kemper IGCC-related costs incurred during construction were initially deferred as regulatory assets. Some of these costs are now included in rates and are being recognized through income; however, such costs continue to be included in the Current Cost Estimate and the Actual Costs at December 31, 2016. The wholesale portion of debt carrying costs, whether deferred or recognized through income, is not included in the Current Cost Estimate and the Actual Costs at December 31, 2016. See "Rate Recovery of Kemper IGCC Costs – Regulatory Assets and Liabilities" herein for additional information.

(f) The Current Cost Estimate and the Actual Costs include $2.76 billion that will not be recovered for costs above the cost cap, $0.83 billion of investment costs included in current rates for the combined cycle and related assets in service, and $0.08 billion of costs that were previously expensed for the combined cycle and related assets in service. The Current Cost Estimate and the Actual Costs exclude $0.25 billion of costs not included in current rates for post-June 2013 mine operations, the lignite fuel inventory, and the nitrogen plant capital lease, which will be included in the 2017 Rate Case to be filed by June 3, 2017. See Note 1 to the financial statements under "Fuel Inventory," Note 6 to the financial statements under "Capital Leases," and "Rate Recovery of Kemper IGCC Costs – 2017 Rate Case" herein for additional information.

Of the total costs, including post-in-service costs for the lignite mine, incurred as of December 31, 2016, $3.67 billion was included in property, plant, and equipment (which is net of the Initial DOE Grants, the Additional DOE Grants, and estimated probable losses of $2.84 billion), $6 million in other property and investments, $75 million in fossil fuel stock, $47 million in materials and supplies, $29 million in other regulatory assets, current, $172 million in other regulatory assets, deferred, $3 million in other current assets, and $14 million in other deferred charges and assets in the balance sheet.

The Company does not intend to seek rate recovery for any costs related to the construction of the Kemper IGCC that exceed the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions. The Company recorded pre-tax charges to income for revisions to the cost estimate of $348 million ($215 million after tax), $365 million ($226 million after tax), and $868 million ($536 million after tax) in 2016, 2015, and 2014, respectively. Since 2012, in the aggregate, the Company has incurred charges of $2.76 billion ($1.71 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through December 31, 2016. The increases to the cost estimate in 2016 primarily reflect $186 million for the extension of the Kemper IGCC's projected in-service date from August 31, 2016 to March 15, 2017 and $162 million for increased efforts related to operational readiness and challenges in start-up and commissioning activities, including the cost of repairs and modifications to both gasifiers, mechanical improvements to coal feed and ash management systems, and outage work, as well as certain post-in-service costs expected to be subject to the cost cap.

In addition to the current construction cost estimate, the Company is identifying potential improvement projects that ultimately may be completed subsequent to placing the remainder of the Kemper IGCC in service. If completed, such improvement projects would be expected to enhance plant performance, safety, and/or operations. As of December 31, 2016, approximately $12 million of related potential costs has been included in the estimated loss on the Kemper IGCC. Other projects have yet to be fully evaluated, have not been included in the current cost estimate, and may be subject to the $2.88 billion cost cap.

Any extension of the in-service date beyond mid-March 2017 is currently estimated to result in additional base costs of approximately $25 million to $35 million per month, which includes maintaining necessary levels of start-up labor, materials, and fuel, as well as operational resources required to execute start-up and commissioning activities. Additional costs may be required for remediation of any further equipment and/or design issues identified. Any extension of the in-service date with respect to the Kemper IGCC beyond mid-March 2017 would also increase costs for the Cost Cap Exceptions, which are not subject to the $2.88 billion cost cap established by the Mississippi PSC. These costs include AFUDC, which is currently estimated to total approximately $16 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting and legal fees of approximately $3 million per month. For additional information, see "2015 Rate Case" herein.

Further cost increases and/or extensions of the expected in-service date may result from factors including, but not limited to, difficulties integrating the systems required for sustained operations, sustaining nitrogen supply, major equipment failure, unforeseen engineering or design problems including any repairs and/or modifications to systems, and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC). Any further changes in the estimated costs of the Kemper IGCC subject to the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions, will be reflected in the Company's statements of income and these changes could be material.

Rate Recovery of Kemper IGCC Costs

Given the variety of potential scenarios and the uncertainty of the outcome of future regulatory proceedings with the Mississippi PSC (and any subsequent related legal challenges), the ultimate outcome of the rate recovery matters discussed herein, including the resolution of legal challenges, cannot now be determined but could result in further material charges that could have a material impact on the Company's results of operations, financial condition, and liquidity.

As of December 31, 2016, in addition to the $2.76 billion of costs above the Mississippi PSC's $2.88 billion cost cap that have been recognized as a charge to income, the Company had incurred approximately $1.99 billion in costs subject to the cost cap and approximately $1.46 billion in Cost Cap Exceptions related to the construction and start-up of the Kemper IGCC that are not included in current rates. These costs primarily relate to the following:

Cost Category	Actual Costs (in billions)
Gasifiers and Gas Clean-up Facilities	$ 1.88
Lignite Mine Facility	0.31
CO_2 Pipeline Facilities	0.11
Combined Cycle and Common Facilities	0.16
AFUDC	0.69
General exceptions	0.07
Plant inventory	0.03
Lignite inventory	0.08
Regulatory and other deferred assets	0.12
Subtotal	$ 3.45
Additional DOE Grants	(0.14)
Total	$ 3.31

Of these amounts, approximately 29% is related to wholesale and approximately 71% is related to retail, including the 15% portion that was previously contracted to be sold to SMEPA. The Company and its wholesale customers have generally agreed to the similar regulatory treatment for wholesale tariff purposes as approved by the Mississippi PSC for retail for Kemper IGCC-related costs. See "FERC Matters – Municipal and Rural Associations Tariff" and "Termination of Proposed Sale of Undivided Interest" herein for further information.

Prudence

On August 17, 2016, the Mississippi PSC issued an order establishing a discovery docket to manage all filings related to the prudence of the Kemper IGCC. On October 3, 2016, the Company made a required compliance filing, which included a review and explanation of differences between the Kemper IGCC project estimate set forth in the 2010 CPCN proceedings and the most recent Kemper IGCC project estimate, as well as comparisons of current cost estimates and current expected plant operational parameters to the estimates presented in the 2010 CPCN proceedings for the first five years after the Kemper IGCC is placed in service. Compared to amounts presented in the 2010 CPCN proceedings, operations and maintenance expenses have increased an average of $105 million annually and maintenance capital has increased an average of $44 million annually for the first full five years of operations for the Kemper IGCC. Additionally, while the current estimated operational availability estimates reflect ultimate results similar to those presented in the 2010 CPCN proceedings, the ramp up period for the current estimates reflects a lower starting point and a slower escalation rate. On November 17, 2016, the Company submitted a supplemental filing to the October 3, 2016 compliance filing to present revised non-fuel operations and maintenance expense projections for the first year after the Kemper IGCC is placed in service. This supplemental filing included approximately $68 million in additional estimated operations and maintenance costs expected to be required to support the operations of the Kemper IGCC during that period. The Company will not seek recovery of the $68 million in additional estimated costs from customers if incurred.

The Company expects the Mississippi PSC to address these matters in connection with the 2017 Rate Case.

Economic Viability Analysis

In the fourth quarter 2016, as a part of its Integrated Resource Plan process, the Southern Company system completed its regular annual updated fuel forecast, the 2017 Annual Fuel Forecast. This updated fuel forecast reflected significantly lower long-term estimated costs for natural gas than were previously projected.

As a result of the updated long-term natural gas forecast, as well as the revised operating expense projections reflected in the discovery docket filings discussed above, on February 21, 2017, the Company filed an updated project economic viability

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analysis of the Kemper IGCC as required under the 2012 MPSC CPCN Order confirming authorization of the Kemper IGCC. The project economic viability analysis measures the life cycle economics of the Kemper IGCC compared to feasible alternatives, natural gas combined cycle generating units, under a variety of scenarios and considering fuel, operating and capital costs, and operating characteristics, as well as federal and state taxes and incentives. The reduction in the projected long-term natural gas prices in the 2017 Annual Fuel Forecast and, to a lesser extent, the increase in the estimated Kemper IGCC operating costs, negatively impact the updated project economic viability analysis.

The Company expects the Mississippi PSC to address this matter in connection with the 2017 Rate Case.

2017 Accounting Order Request

After the remainder of the plant is placed in service, AFUDC equity of approximately $11 million per month will no longer be recorded in income, and the Company expects to incur approximately $25 million per month in depreciation, taxes, operations and maintenance expenses, interest expense, and regulatory costs in excess of current rates. The Company expects to file a request for authority from the Mississippi PSC and the FERC to defer all Kemper IGCC costs incurred after the in-service date that cannot be capitalized, are not included in current rates, and are not required to be charged against earnings as a result of the $2.88 billion cost cap until such time as the Mississippi PSC completes its review and includes the resulting allowable costs in rates. In the event that the Mississippi PSC does not grant the Company's request, these monthly expenses will be charged to income as incurred and will not be recoverable through rates.

2017 Rate Case

The Company continues to believe that all costs related to the Kemper IGCC have been prudently incurred in accordance with the requirements of the 2012 MPSC CPCN Order. The Company also recognizes significant areas of potential challenge during future regulatory proceedings (and any subsequent, related legal challenges) exist. As described further herein and under "Prudence," "Lignite Mine and CO_2 Pipeline Facilities," "Termination of Proposed Sale of Undivided Interest," and "Income Tax Matters," these challenges include, but are not limited to, prudence issues associated with capital costs, financing costs (AFUDC), and future operating costs net of chemical revenues; potential operating parameters; income tax issues; costs deferred as regulatory assets; and the 15% portion of the project previously contracted to SMEPA.

Legislation to authorize a multi-year rate plan and legislation to provide for alternate financing through securitization of up to $1.0 billion of prudently-incurred costs was enacted into law in 2013. The Company expects to utilize this legislation to securitize prudently-incurred qualifying facility costs in excess of the certificated cost estimate of $2.4 billion. Qualifying facility costs include, but are not limited to, pre-construction costs, construction costs, regulatory costs, and accrued AFUDC. The Court's decision regarding the 2013 MPSC Rate Order did not impact the Company's ability to utilize alternate financing through securitization or the February 2013 legislation.

Although the 2017 Rate Case has not yet been filed and is subject to future developments with either the Kemper IGCC or the Mississippi PSC, consistent with its approach in the 2013 and 2015 rate proceedings in accordance with the law passed in 2013 authorizing multi-year rate plans, the Company is developing both a traditional rate case requesting full cost recovery of the amounts not currently in rates and a rate mitigation plan that together represent the Company's probable filing strategy. The Company also expects that timely resolution of the 2017 Rate Case will likely require a negotiated settlement agreement. In the event an agreement acceptable to both the Company and the MPUS (and other parties) can be negotiated and ultimately approved by the Mississippi PSC, it is reasonably possible that full regulatory recovery of all Kemper IGCC costs will not occur. The impact of such an agreement on the Company's financial statements would depend on the method, amount, and type of cost recovery ultimately excluded. Certain costs, including operating costs, would be recorded to income in the period incurred, while other costs, including investment-related costs, would be charged to income when it is probable they will not be recovered and the amounts can be reasonably estimated. In the event an agreement acceptable to the parties cannot be reached, the Company intends to fully litigate its request for full recovery through the Mississippi PSC regulatory process and any subsequent legal challenges.

The Company has evaluated various scenarios in connection with its processes to prepare the 2017 Rate Case and has recognized an additional $80 million charge to income, which is the estimated minimum probable amount of the $3.31 billion of Kemper IGCC costs not currently in rates that would not be recovered under the probable rate mitigation plan to be filed by June 3, 2017.

2015 Rate Case

On August 13, 2015, the Mississippi PSC approved the Company's request for interim rates, which presented an alternative rate proposal (In-Service Asset Proposal) designed to recover the Company's costs associated with the Kemper IGCC assets that are commercially operational and currently providing service to customers (the transmission facilities, combined cycle, natural gas pipeline, and water pipeline) and other related costs. The interim rates were designed to collect approximately $159 million annually and became effective in September 2015, subject to refund and certain other conditions.

On December 3, 2015, the Mississippi PSC issued the In-Service Asset Rate Order adopting in full the 2015 Stipulation entered into between the Company and the MPUS regarding the In-Service Asset Proposal. The In-Service Asset Rate Order provided for retail rate recovery of an annual revenue requirement of approximately $126 million, based on the Company's actual average capital structure, with a maximum common equity percentage of 49.733%, a 9.225% return on common equity, and actual embedded interest costs. The In-Service Asset Rate Order also included a prudence finding of all costs in the stipulated revenue requirement calculation for the in-service assets. The stipulated revenue requirement excluded the costs of the Kemper IGCC related to the 15% undivided interest that was previously projected to be purchased by SMEPA but reserved the Company's right to seek recovery in a future proceeding. See "Termination of Proposed Sale of Undivided Interest" herein for additional information. The Company is required to file the 2017 Rate Case by June 3, 2017.

With implementation of the new rates on December 17, 2015, the interim rates were terminated and, in March 2016, the Company completed customer refunds of approximately $11 million for the difference between the interim rates collected and the permanent rates.

2013 MPSC Rate Order

In January 2013, the Company entered into a settlement agreement with the Mississippi PSC that was intended to establish the process for resolving matters regarding cost recovery related to the Kemper IGCC (2013 Settlement Agreement). Under the 2013 Settlement Agreement, the Company agreed to limit the portion of prudently-incurred Kemper IGCC costs to be included in retail rate base to the $2.4 billion certificated cost estimate, plus the Cost Cap Exceptions, but excluding AFUDC, and any other costs permitted or determined to be excluded from the $2.88 billion cost cap by the Mississippi PSC. In March 2013, the Mississippi PSC issued a rate order approving retail rate increases of 15% effective March 19, 2013 and 3% effective January 1, 2014, which collectively were designed to collect $156 million annually beginning in 2014 (2013 MPSC Rate Order) to be used to mitigate customer rate impacts after the Kemper IGCC is placed in service, based on a mirror CWIP methodology (Mirror CWIP rate).

On February 12, 2015, the Court reversed the 2013 MPSC Rate Order based on, among other things, its findings that (1) the Mirror CWIP rate treatment was not provided for under the Baseload Act and (2) the Mississippi PSC should have determined the prudence of Kemper IGCC costs before approving rate recovery through the 2013 MPSC Rate Order. The Court also found the 2013 Settlement Agreement unenforceable due to a lack of public notice for the related proceedings. On July 7, 2015, the Mississippi PSC ordered that the Mirror CWIP rate be terminated effective July 20, 2015 and required the fourth quarter 2015 refund of the $342 million collected under the 2013 MPSC Rate Order, along with associated carrying costs of $29 million. The Court's decision did not impact the 2012 MPSC CPCN Order or the February 2013 legislation described above.

Because the 2013 MPSC Rate Order did not provide for the inclusion of CWIP in rate base as permitted by the Baseload Act, the Company continues to record AFUDC on the Kemper IGCC. Through December 31, 2016, AFUDC recorded since the original May 2014 estimated in-service date for the Kemper IGCC has totaled $398 million, which will continue to accrue at approximately $16 million per month until the remainder of the plant is placed in service. The Company has not recorded any AFUDC on Kemper IGCC costs in excess of the $2.88 billion cost cap, except for Cost Cap Exception amounts.

2012 MPSC CPCN Order

The 2012 MPSC CPCN Order included provisions relating to both the Company's recovery of financing costs during the course of construction of the Kemper IGCC and the Company's recovery of costs following the date the Kemper IGCC is placed in service. With respect to recovery of costs following the in-service date of the Kemper IGCC, the 2012 MPSC CPCN Order provided for the establishment of operational cost and revenue parameters including availability factor, heat rate, lignite heat content, and chemical revenue based upon assumptions in the Company's petition for the CPCN. The Company expects the Mississippi PSC to apply operational parameters in connection with the 2017 Rate Case and future proceedings related to the operation of the Kemper IGCC. To the extent the Mississippi PSC determines the Kemper IGCC does not meet the operational parameters ultimately adopted by the Mississippi PSC or the Company incurs additional costs to satisfy such parameters, there could be a material adverse impact on the Company's financial statements. See "Prudence" herein for additional information.

Regulatory Assets and Liabilities

Consistent with the treatment of non-capital costs incurred during the pre-construction period, the Mississippi PSC issued an accounting order in 2011 granting the Company the authority to defer all non-capital Kemper IGCC-related costs to a regulatory asset through the in-service date, subject to review of such costs by the Mississippi PSC. Such costs include, but are not limited

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to, carrying costs on Kemper IGCC assets currently placed in service, costs associated with Mississippi PSC and MPUS consultants, prudence costs, legal fees, and operating expenses associated with assets placed in service.

In August 2014, the Company requested confirmation by the Mississippi PSC of the Company's authority to defer all operating expenses associated with the operation of the combined cycle subject to review of such costs by the Mississippi PSC. In addition, the Company is authorized to accrue carrying costs on the unamortized balance of such regulatory assets at a rate and in a manner to be determined by the Mississippi PSC in future cost recovery mechanism proceedings. Beginning in the third quarter 2015 and the second quarter 2016, in connection with the implementation of retail and wholesale rates, respectively, the Company began expensing certain ongoing project costs and certain retail debt carrying costs (associated with assets placed in service and other non-CWIP accounts) that previously were deferred as regulatory assets and began amortizing certain regulatory assets associated with assets placed in service and consulting and legal fees. The amortization periods for these regulatory assets vary from two years to 10 years as set forth in the In-Service Asset Rate Order and the settlement agreement with wholesale customers. As of December 31, 2016, the balance associated with these regulatory assets was $97 million, of which $29 million is included in current assets. Other regulatory assets associated with the remainder of the Kemper IGCC totaled $104 million as of December 31, 2016. The amortization period for these assets is expected to be determined by the Mississippi PSC in the 2017 Rate Case. See "FERC Matters" herein for additional information related to the 2016 settlement agreement with wholesale customers.

The In-Service Asset Rate Order requires the Company to submit an annual true-up calculation of its actual cost of capital, compared to the stipulated total cost of capital, with the first occurring as of May 31, 2016. At December 31, 2016, the Company's related regulatory liability included in its balance sheet totaled approximately $7 million. See "2015 Rate Case" herein for additional information.

Also see Note 1 to the financial statements under "Regulatory Assets and Liabilities" for additional information.

Lignite Mine and CO_2 Pipeline Facilities

In conjunction with the Kemper IGCC, the Company owns the lignite mine and equipment and has acquired and will continue to acquire mineral reserves located around the Kemper IGCC site. The mine started commercial operation in June 2013.

In 2010, the Company executed a 40-year management fee contract with Liberty Fuels Company, LLC (Liberty Fuels), a wholly-owned subsidiary of The North American Coal Corporation, which developed, constructed, and is operating and managing the mining operations. The contract with Liberty Fuels is effective through the end of the mine reclamation. As the mining permit holder, Liberty Fuels has a legal obligation to perform mine reclamation and the Company has a contractual obligation to fund all reclamation activities. In addition to the obligation to fund the reclamation activities, the Company currently provides working capital support to Liberty Fuels through cash advances for capital purchases, payroll, and other operating expenses. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" and "Variable Interest Entities" for additional information.

In addition, the Company has constructed and will operate the CO_2 pipeline for the planned transport of captured CO_2 for use in enhanced oil recovery. The Company entered into agreements with Denbury Onshore (Denbury) and Treetop Midstream Services, LLC (Treetop), pursuant to which Denbury would purchase 70% of the CO_2 captured from the Kemper IGCC and Treetop would purchase 30% of the CO_2 captured from the Kemper IGCC. On June 3, 2016, the Company cancelled its contract with Treetop and amended its contract with Denbury to reflect, among other things, Denbury's agreement to purchase 100% of the CO_2 captured from the Kemper IGCC, an initial contract term of 16 years, and termination rights if the Company has not satisfied its contractual obligation to deliver captured CO_2 by July 1, 2017, in addition to Denbury's existing termination rights in the event of a change in law, force majeure, or an event of default by the Company. Any termination or material modification of the agreement with Denbury could impact the operations of the Kemper IGCC and result in a material reduction in the Company's revenues to the extent the Company is not able to enter into other similar contractual arrangements or otherwise sequester the CO_2 produced.

Additionally, sustained oil price reductions could result in significantly lower revenues than the Company originally forecasted to be available to offset customer rate impacts, which could have a material impact on the Company's financial statements.

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

Termination of Proposed Sale of Undivided Interest

In 2010 and as amended in 2012, the Company and SMEPA entered into an agreement whereby SMEPA agreed to purchase a 15% undivided interest in the Kemper IGCC (15% Undivided Interest). On May 20, 2015, SMEPA notified the Company of its termination of the agreement. The Company previously received a total of $275 million of deposits from SMEPA that were required to be returned to SMEPA with interest. On June 3, 2015, Southern Company, pursuant to its guarantee obligation,

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returned approximately $301 million to SMEPA. Subsequently, the Company issued a promissory note in the aggregate principal amount of approximately $301 million to Southern Company, which matures on December 1, 2017.

Litigation

On April 26, 2016, a complaint against the Company was filed in Harrison County Circuit Court (Circuit Court) by Biloxi Freezing & Processing Inc., Gulfside Casino Partnership, and John Carlton Dean, which was amended and refiled on July 11, 2016 to include, among other things, Southern Company as a defendant. On August 12, 2016, Southern Company and the Company removed the case to the U.S. District Court for the Southern District of Mississippi. The plaintiffs filed a request to remand the case back to state court, which was granted on November 17, 2016. The individual plaintiff, John Carlton Dean, alleges that the Company and Southern Company violated the Mississippi Unfair Trade Practices Act. All plaintiffs have alleged that the Company and Southern Company concealed, falsely represented, and failed to fully disclose important facts concerning the cost and schedule of the Kemper IGCC and that these alleged breaches have unjustly enriched the Company and Southern Company. The plaintiffs seek unspecified actual damages and punitive damages; ask the Circuit Court to appoint a receiver to oversee, operate, manage, and otherwise control all affairs relating to the Kemper IGCC; ask the Circuit Court to revoke any licenses or certificates authorizing the Company or Southern Company to engage in any business related to the Kemper IGCC in Mississippi; and seek attorney's fees, costs, and interest. The plaintiffs also seek an injunction to prevent any Kemper IGCC costs from being charged to customers through electric rates. On December 7, 2016, Southern Company and the Company filed motions to dismiss.

On June 9, 2016, Treetop, Greenleaf, Tenrgys, LLC, Tellus Energy, LLC, WCOA, LLC, and Tellus Operating Group filed a complaint against the Company, Southern Company, and SCS in the state court in Gwinnett County, Georgia. The complaint relates to the cancelled CO_2 contract with Treetop and alleges fraudulent misrepresentation, fraudulent concealment, civil conspiracy, and breach of contract on the part of the Company, Southern Company, and SCS and seeks compensatory damages of $100 million, as well as unspecified punitive damages. Southern Company, the Company, and SCS have moved to compel arbitration pursuant to the terms of the CO_2 contract.

The Company believes these legal challenges have no merit; however, an adverse outcome in these proceedings could have a material impact on the Company's results of operations, financial condition, and liquidity. The Company will vigorously defend itself in these matters, and the ultimate outcome of these matters cannot be determined at this time.

Baseload Act

In 2008, the Baseload Act was signed by the Governor of Mississippi. The Baseload Act authorizes, but does not require, the Mississippi PSC to adopt a cost recovery mechanism that includes in retail base rates, prior to and during construction, all or a portion of the prudently-incurred pre-construction and construction costs incurred by a utility in constructing a base load electric generating plant. Prior to the passage of the Baseload Act, such costs would traditionally be recovered only after the plant was placed in service. The Baseload Act also provides for periodic prudence reviews by the Mississippi PSC and prohibits the cancellation of any such generating plant without the approval of the Mississippi PSC. In the event of cancellation of the construction of the plant without approval of the Mississippi PSC, the Baseload Act authorizes the Mississippi PSC to make a public interest determination as to whether and to what extent the utility will be afforded rate recovery for costs incurred in connection with such cancelled generating plant. See "Rate Recovery of Kemper IGCC Costs" herein for additional information.

Income Tax Matters

See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information about the Kemper IGCC.

Bonus Depreciation

In December 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. Bonus depreciation was extended for qualified property placed in service through 2020. The PATH Act allows for 50% bonus depreciation for 2015 through 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 bonus depreciation included in the PATH Act is expected to result in approximately $20 million of positive cash flows for the 2016 tax year, which was not all realized in 2016 due to a projected consolidated net operating loss (NOL) for Southern Company. Dependent upon placing the remainder of the Kemper IGCC in service by December 31, 2017, the Company expects approximately $370 million of positive cash flows from bonus depreciation for the 2017 tax year, which may not all be realized in 2017 due to additional NOL projections for the 2017 tax year. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" and Note 5 to the financial statements under "Current and Deferred Income Taxes – Net Operating Loss" for additional information. The ultimate outcome of this matter cannot be determined at this time.

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Investment Tax Credits

The IRS allocated $133 million (Phase I) and $279 million (Phase II) of Internal Revenue Code Section 48A tax credits to the Company in connection with the Kemper IGCC. These tax credits were dependent upon meeting the IRS certification requirements, including an in-service date no later than May 11, 2014 for the Phase I credits and April 19, 2016 for the Phase II credits. In addition, the capture and sequestration (via enhanced oil recovery) of at least 65% of the CO_2 produced by the Kemper IGCC during operations in accordance with the Internal Revenue Code was also a requirement of the Phase II credits. As a result of schedule extensions for the Kemper IGCC, the Phase I tax credits were recaptured in 2013 and the Phase II tax credits were recaptured in 2015.

Section 174 Research and Experimental Deduction

Southern Company, on behalf of the Company, has reflected deductions for research and experimental (R&E) expenditures related to the Kemper IGCC in its federal income tax calculations since 2013 and has filed amended federal income tax returns for 2008 through 2013 to also include such deductions. The Kemper IGCC is based on first-of-a-kind technology, and Southern Company believes that a significant portion of the plant costs qualify as deductible R&E expenditures under Internal Revenue Code Section 174. In December 2016, Southern Company and the IRS reached a proposed settlement, subject to approval of the U.S. Congress Joint Committee on Taxation, resolving a methodology for these deductions. Due to the uncertainty related to this tax position, the Company had unrecognized tax benefits associated with these R&E deductions totaling approximately $464 million as of December 31, 2016. See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information. This matter is expected to be resolved in the next 12 months; however, the ultimate outcome of this matter cannot be determined at this time.

Other Matters

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters.

The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

In 2013, the Company submitted a claim under the Deepwater Horizon Economic and Property Damages Settlement Agreement associated with the oil spill that occurred in 2010 in the Gulf of Mexico. The ultimate outcome of this matter cannot be determined at this time.

The SEC is conducting a formal investigation of Southern Company and the Company concerning the estimated costs and expected in-service date of the Kemper IGCC. Southern Company and the Company believe the investigation is focused primarily on periods subsequent to 2010 and on accounting matters, disclosure controls and procedures, and internal controls over financial reporting associated with the Kemper IGCC. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" herein for additional information on the Kemper IGCC estimated construction costs and expected in-service date. The ultimate outcome of this matter cannot be determined at this time; however, it is not expected to have a material impact on the Company's financial statements.

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.

Utility Regulation

The Company is subject to retail regulation by the Mississippi PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation and pension and other 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.

Kemper IGCC Estimated Construction Costs, Project Completion Date, and Rate Recovery

During 2016, the Company further revised its cost estimate to complete construction and start-up of the Kemper IGCC to an amount that exceeds the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions. The Company does not intend to seek any rate recovery for any costs related to the construction of the Kemper IGCC that exceed the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions.

As a result of revisions to the cost estimate, the Company recorded total pre-tax charges to income for the estimated probable losses on the Kemper IGCC subject to the construction cost cap of $127 million ($78 million after tax) in the fourth quarter 2016, $88 million ($54 million after tax) in the third quarter 2016, $81 million ($50 million after tax) in the second quarter 2016, $53 million ($33 million after tax) in the first quarter 2016, $183 million ($113 million after tax) in the fourth quarter 2015, $150 million ($93 million after tax) in the third quarter 2015, $23 million ($14 million after tax) in the second quarter 2015, $9 million ($6 million after tax) in the first quarter 2015, $70 million ($43 million after tax) in the fourth quarter 2014, $418 million ($258 million after tax) in the third quarter 2014, $380 million ($235 million after tax) in the first quarter 2014, $40 million ($25 million after tax) in the fourth quarter 2013, $150 million ($93 million after tax) in the third quarter 2013, $450 million ($278 million after tax) in the second quarter 2013, $462 million ($285 million after tax) in the first quarter 2013, and $78 million ($48 million after tax) in the fourth quarter 2012. In the aggregate, the Company has incurred charges of $2.76 billion ($1.71 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through December 31, 2016.

The Company's revised cost estimate reflects an expected in-service date of mid-March 2017 and includes certain post-in-service costs which are expected to be subject to the cost cap. The Company has experienced, and may continue to experience, material changes in the cost estimate for the Kemper IGCC. Further cost increases and/or extensions of the expected in-service date may result from factors including, but not limited to, difficulties integrating the systems required for sustained operations, sustaining nitrogen supply, major equipment failure, unforeseen engineering or design problems including any repairs and/or modifications to systems, and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC).

In addition to the current construction cost estimate, the Company is also identifying potential improvement projects that ultimately may be completed subsequent to placing the remainder of the Kemper IGCC in service. If completed, such improvement projects would be expected to enhance plant performance, safety, and/or operations. As of December 31, 2016, approximately $12 million of related potential costs has been included in the estimated loss on the Kemper IGCC. Other projects have yet to be fully evaluated, have not been included in the current cost estimate, and may be subject to the $2.88 billion cost cap. In subsequent periods, any further changes in the estimated costs of the Kemper IGCC subject to the $2.88 billion cost cap, net of the Initial DOE Grants and excluding the Cost Cap Exceptions, will be reflected in the statements of income and these changes could be material.

Any extension of the in-service date beyond mid-March 2017 is currently estimated to result in additional base costs of approximately $25 million to $35 million per month, which includes maintaining necessary levels of start-up labor, materials, and fuel, as well as operational resources required to execute start-up and commissioning activities. However, additional costs may be required for remediation of any further equipment and/or design issues identified. Any extension of the in-service date with respect to the Kemper IGCC beyond mid-March 2017 would also increase costs for the Cost Cap Exceptions, which are not subject to the $2.88 billion cost cap established by the Mississippi PSC. These costs include AFUDC, which is currently estimated to total approximately $16 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting and legal fees of approximately $3 million per month.

The Company continues to believe that all costs related to the Kemper IGCC have been prudently incurred in accordance with the requirements of the 2012 MPSC CPCN Order. The Company also recognizes significant areas of potential challenge during future regulatory proceedings (and any subsequent, related legal challenges) exist. As described further under FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs," " – Prudence," " – Lignite Mine and CO_2 Pipeline Facilities," and " – Termination of Proposed Sale of Undivided Interest" and "Income Tax Matters," these challenges include, but are not limited to, prudence issues associated with capital costs, financing costs (AFUDC), and future operating costs, net of chemical revenues; potential operating parameters; income tax issues; costs deferred as regulatory assets; and the 15% portion of the project previously contracted to SMEPA.

Although the 2017 Rate Case has not yet been filed and is subject to future developments with either the Kemper IGCC or the Mississippi PSC, consistent with its approach in the 2013 and 2015 rate proceedings in accordance with the law passed in 2013 authorizing multi-year rate plans, the Company is developing both a traditional rate case requesting full cost recovery of the amounts not currently in rates and a rate mitigation plan that together represent the Company's probable filing strategy. The Company also expects that timely resolution of the 2017 Rate Case will likely require a negotiated settlement agreement. In the event an agreement acceptable to both the Company and the MPUS (and other parties) can be negotiated and ultimately approved by the Mississippi PSC, it is reasonably possible that full regulatory recovery of all Kemper IGCC costs will not occur. The impact of such an agreement on the Company's financial statements would depend on the method, amount, and type of cost recovery ultimately excluded. Certain costs, including operating costs, would be recorded to income in the period incurred, while other costs, including investment-related costs, would be charged to income when it is probable they will not be recovered and the amounts can be reasonably estimated. In the event an agreement acceptable to the parties cannot be reached, the Company intends to fully litigate its request for full recovery through the Mississippi PSC regulatory process and any subsequent legal challenges.

The Company has evaluated various scenarios in connection with its processes to prepare the 2017 Rate Case and has recognized an additional $80 million charge to income, which is the estimated minimum probable amount of the $3.31 billion of Kemper IGCC costs not currently in rates that would not be recovered under the probable rate mitigation plan to be filed by June 3, 2017.

Given the significant judgment involved in estimating the future costs to complete construction and start-up, the project completion date, the ultimate rate recovery for the Kemper IGCC, and the potential impact on results of operations, the Company considers these items to be critical accounting estimates. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

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 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, deep injection wells, water wells, substation removal, mine reclamation, and asbestos removal. 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 cost estimates for AROs related to the disposal of CCR 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. 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 with respect to compliance activities, 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. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Coal Combustion Residuals" herein for additional information.

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" 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 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 decreased by approximately $4 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 $2 million or less change in total annual benefit expense and a $19 million or less change in projected obligations.

See Note 2 to the financial statements for additional information regarding pension and other postretirement benefits.

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 over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in the calculation of taxable income. The average annual AFUDC rate was 6.5%, 5.99%, and 6.91% for the years ended December 31, 2016, 2015, and 2014, respectively. The AFUDC rate is applied to CWIP consistent with jurisdictional regulatory treatment. AFUDC equity was $124 million, $110 million, and $136 million in 2016, 2015, and 2014, respectively.

Unbilled Revenues

Revenues related to the retail sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated. Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, power delivery volume, and other operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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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, income tax, 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 and records a tax asset or liability if it is more likely than not that a tax position will be sustained. 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

In 2014, the FASB issued ASC 606, Revenue from Contracts with Customers, replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the guidance is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers.

While the Company expects most of its revenue to be included in the scope of ASC 606, it has not fully completed its evaluation of such arrangements. The majority of the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term. For such arrangements, the Company generally expects that the revenue from contracts with these customers will continue to be equivalent to the electricity supplied and billed in that period (including unbilled revenues) and the adoption of ASC 606 will not result in a significant shift in the timing of revenue recognition for such sales.

The Company's ongoing evaluation of other revenue streams and related contracts includes longer term contractual commitments and unregulated sales to customers. Some revenue arrangements, such as certain PPAs and alternative revenue programs, are expected to be excluded from the scope of ASC 606 and therefore, be accounted for and presented separately from revenues under ASC 606 on the Company's financial statements. In addition, the power and utilities industry is currently addressing other specific industry issues, including the applicability of ASC 606 to contributions in aid of construction (CIAC). If final implementation guidance indicates CIAC will be accounted for under ASC 606 and offsetting regulatory treatment is not permitted, it could have a material impact on the Company's financial statements.

The new standard is effective for interim and annual reporting periods beginning after December 15, 2017. The Company must select a transition method to be applied either retrospectively to each prior reporting period presented or retrospectively with a cumulative effect adjustment to retained earnings at the date of initial adoption. As the ultimate impact of the new standard has not yet been determined, the Company has not elected its transition method.

On February 25, 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842) (ASU 2016-02). ASU 2016-02 requires lessees to recognize on the balance sheet a lease liability and a right-of-use asset for all leases. ASU 2016-02 also changes the recognition, measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The Company is currently evaluating the new standard and has not yet determined its ultimate impact; however, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

On March 30, 2016, the FASB issued ASU No. 2016-09, Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting (ASU 2016-09). ASU 2016-09 changes the accounting for income taxes and the cash flow presentation for share-based payment award transactions effective for fiscal years beginning after December 15, 2016. The new guidance requires all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation to be recognized as income tax expense or benefit in the income statement. Previously, the Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities rather than net cash provided from financing activities on the statement of cash flows. The Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. The Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of the Company. See Notes 5, 8, and 11 to the financial statements for disclosures impacted by ASU 2016-09.

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On October 24, 2016, the FASB issued ASU No. 2016-16, Income Taxes (Topic 740), Intra-Entity Transfers of Assets Other Than Inventory (ASU 2016-16). Current GAAP prohibits the recognition of current and deferred income taxes for an affiliate asset transfer until the asset has been sold to an outside party. ASU 2016-16 requires an entity to recognize the income tax consequences of an affiliate transfer of an asset other than inventory when the transfer occurs. ASU 2016-16 is effective for annual reporting periods beginning after December 15, 2017 and interim periods within those annual periods. The amendments will be applied on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. The Company is currently assessing the impact of the standard on its financial statements and has not yet determined its ultimate impact.

In 2014, the FASB issued ASU No. 2014-15, Presentation of Financial Statements-Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern (ASU 2014-15). ASU 2014-15 defines management's responsibility to evaluate whether there is substantial doubt about an organization's ability to continue as a going concern within one year of the date the financial statements are issued and to provide related footnote disclosures including management's plans that alleviate substantial doubt. ASU 2014-15 became effective for fiscal years ending after December 15, 2016 and the Company has included the disclosures required by ASU 2014-15 in Note 6 to the financial statements under "Going Concern."

FINANCIAL CONDITION AND LIQUIDITY

Overview

Earnings for all periods presented were negatively affected by revisions to the cost estimate for the Kemper IGCC. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" herein for additional information.

The Company's capital expenditures and debt maturities are expected to materially exceed operating cash flows through 2021. In addition to the Kemper IGCC, projected capital expenditures in that period include investments to maintain existing generation facilities, to add environmental modifications to existing generating units, and to expand and improve transmission and distribution facilities.

As of December 31, 2016, the Company's current liabilities exceeded current assets by approximately $371 million primarily due to $551 million in promissory notes to Southern Company which mature in December 2017, $35 million in senior notes which mature in November 2017, and $63 million in short-term debt. The Company expects the funds needed to satisfy the promissory notes to Southern Company will exceed amounts available from operating cash flows, lines of credit, and other external sources. Accordingly, the Company intends to satisfy these obligations through loans and/or equity contributions from Southern Company. Specifically, the Company has been informed by Southern Company that, in the event sufficient funds are not available from external sources, Southern Company intends to (i) extend the maturity of the $551 million in promissory notes and (ii) provide Mississippi Power with loans and/or equity contributions sufficient to fund the remaining indebtedness scheduled to mature and other cash needs over the next 12 months. Therefore, the Company's financial statement presentation contemplates continuation of the Company as a going concern as a result of Southern Company's anticipated ongoing financial support of the Company, consistent with the requirements of ASU 2014-15. See Note 1 to the financial statements under "Recently Issued Accounting Standards" for additional information regarding ASU 2014-15.

The Company's investments in the qualified pension plan increased in value as of December 31, 2016 as compared to December 31, 2015. On December 19, 2016, the Company voluntarily contributed $47 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated during 2017.

Net cash provided from operating activities totaled $229 million for 2016, an increase of $56 million as compared to 2015. The increase in cash provided from operating activities in 2016 was primarily due to repayment in 2015 of ITCs relating to the Kemper IGCC, as well as the 2015 mirror CWIP refund, partially offset by lower income tax benefits related to the Kemper IGCC in 2016 and lower fuel rates in 2016. Net cash provided from operating activities totaled $173 million for 2015, a decrease of $562 million as compared to 2014. The decrease in net cash provided from operating activities was primarily due to lower R&E tax deductions and lower incremental benefit of ITCs relating to the Kemper IGCC reducing income tax refunds, as well as a decrease in the Mirror CWIP regulatory liability due to the Mirror CWIP refund, partially offset by increases in over recovered regulatory clause revenues and customer liability associated with the Mirror CWIP refund.

Net cash used for investing activities in 2016, 2015, and 2014 totaled $697 million, $906 million, and $1.3 billion, respectively. The cash used for investing activities in 2016 was primarily due to gross property additions related to the Kemper IGCC, partially offset by the receipt of Additional DOE Grants. The cash used for investing activities in 2015 and 2014 was primarily due to gross property additions related to the Kemper IGCC and the Plant Daniel scrubber project.

Net cash provided from financing activities totaled $594 million in 2016 primarily due to long-term debt financings and capital contributions from Southern Company, partially offset by a decrease in short-term borrowings and redemptions of long-term debt.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Net cash provided from financing activities totaled $698 million in 2015 primarily due to short-term borrowings, capital contributions from Southern Company, and long-term debt financings, partially offset by redemptions of long-term debt. Net cash provided from financing activities totaled $593 million in 2014 primarily due to capital contributions from Southern Company, long-term debt financings, and the receipts of interest bearing refundable deposits previously pending, partially offset by redemptions of long-term debt.

Significant balance sheet changes as of December 31, 2016 compared to 2015 included an increase in long-term debt of $538 million. A portion of this debt was used to repay securities and notes payable resulting in a $99 million decrease in securities due within one year and a $477 million decrease in notes payable. Additionally, CWIP increased $291 million primarily due to the Kemper IGCC and the required refund of Mirror CWIP collections which reduced the related customer liability by $72 million. Other significant changes include a $383 million increase in accrued income taxes offset by unrecognized tax benefits of $368 million reclassified from long-term to current. Total common stockholder's equity increased $584 million primarily due to the receipt of capital contributions from Southern Company.

The Company's ratio of common equity to total capitalization plus short-term debt was 45.2% and 47.1% at December 31, 2016 and 2015, respectively. See Note 6 to the financial statements for additional information.

Sources of Capital

As discussed above, the Company's financial condition and its ability to obtain funds needed for normal business operations and completion of the construction and start-up of the Kemper IGCC were adversely affected for all periods presented by events relating to the Kemper IGCC. In December 2015, the Mississippi PSC approved the In-Service Asset Rate Order, which among other things, provided for retail rate recovery of an annual revenue requirement of approximately $126 million effective December 17, 2015. The amount, type, and timing of future financings will depend upon regulatory approval, prevailing market conditions, and other factors, which includes resolution of Kemper IGCC cost recovery. See "Capital Requirements and Contractual Obligations" herein and FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs" herein for additional information.

As of December 31, 2016, the Company's current liabilities exceeded current assets by approximately $371 million primarily due to $551 million in promissory notes to Southern Company which mature in December 2017, $35 million in senior notes which mature in November 2017, and $63 million in short-term debt. The Company expects the funds needed to satisfy the promissory notes to Southern Company will exceed amounts available from operating cash flows, lines of credit, and other external sources. Accordingly, the Company intends to satisfy these obligations through loans and/or equity contributions from Southern Company. Specifically, the Company has been informed by Southern Company that, in the event sufficient funds are not available from external sources, Southern Company intends to (i) extend the maturity of the $551 million in promissory notes and (ii) provide Mississippi Power with loans and/or equity contributions sufficient to fund the remaining indebtedness scheduled to mature and other cash needs over the next 12 months. Therefore, the Company's financial statement presentation contemplates continuation of the Company as a going concern as a result of Southern Company's anticipated ongoing financial support of the Company, consistent with the requirements of ASU 2014-15. See Note 1 to the financial statements under "Recently Issued Accounting Standards" for additional information regarding ASU 2014-15.

The Company received $245 million of Initial DOE Grants in prior years that were used for the construction of the Kemper IGCC. An additional $25 million of grants from the DOE is expected to be received for commercial operation of the Kemper IGCC. On April 8, 2016, the Company received approximately $137 million in Additional DOE Grants for the Kemper IGCC, which are expected to be used to reduce future rate impacts for customers. In addition, see Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for information regarding legislation related to the securitization of certain costs of the Kemper IGCC.

The issuance of securities by the Company is subject to regulatory approval by the FERC. Additionally, public offerings of securities are required to be registered with the SEC under the Securities Act of 1933, as amended. The amounts of securities authorized by the FERC are continuously monitored and appropriate filings are made to ensure flexibility in raising capital. Any future financing through secured debt would also require approval by the Mississippi PSC.

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.

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At December 31, 2016, the Company had approximately $224 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2016 were as follows:

Expires			Executable Term Loans		Expires Within One Year	
2017	Total	Unused	One Year	Two Years	Term Out	No Term Out
(in millions)	(in millions)		(in millions)		(in millions)	
$173	$173	$ 150	$ —	$ 13	$13	$160

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

Most of these bank credit arrangements, as well as the Company's term loan arrangements, contain covenants that limit debt levels and typically contain cross acceleration or cross default provisions to other indebtedness (including guarantee obligations) of the Company. Such cross default provisions to other indebtedness would trigger an event of default if the Company defaulted on indebtedness or guarantee obligations over a specific threshold. 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. At December 31, 2016, the Company was in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowing.

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 $150 million unused credit arrangements with banks is allocated to provide liquidity support to the Company's pollution control revenue bonds and commercial paper borrowings. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2016 was approximately $40 million.

Short-term borrowings are included in notes payable in the balance sheets. The Company had no short-term borrowings in 2014. Details of short-term borrowing for 2015 and 2016 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 Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		(in millions)		(in millions)
December 31, 2016	$23	2.6 %	$112	2.0 %	$ 500
December 31, 2015	$500	1.4 %	$372	1.3 %	$ 515

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

Financing Activities

In addition to any financings that may be necessary to meet capital requirements, contractual obligations, and storm restoration costs, 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.

Bank Term Loan and Senior Notes

In March 2016, the Company entered into an unsecured term loan agreement with a syndicate of financial institutions for an aggregate amount of $1.2 billion. The Company borrowed $900 million in March 2016 under the term loan agreement and the remaining $300 million in October 2016. The Company used the initial proceeds to repay $900 million in maturing bank loans in March 2016 and the remaining $300 million to repay at maturity the Company's Series 2011A 2.35% Senior Notes due October 15, 2016. This loan matures on April 1, 2018 and bears interest based on one-month LIBOR.

This bank loan has covenants that limit debt levels to 65% of total capitalization, as defined in the agreement. For purposes of this definition, debt excludes the long-term debt payable to affiliated trusts, other hybrid securities, and securitized debt relating to the contemplated securitization of certain costs of the Kemper IGCC. At December 31, 2016, the Company was in compliance with its debt limit.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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In addition, this bank loan contains cross acceleration provisions to other debt (including guarantee obligations) that would be triggered if the Company defaulted on debt above a specified threshold, the payment of which was then accelerated. The Company is currently in compliance with all such covenants.

Parent Company Loans and Equity Contributions

On January 28, 2016, the Company issued a promissory note for up to $275 million to Southern Company, which matures in December 2017, bearing interest based on one-month LIBOR. During 2016, the Company borrowed $100 million under this promissory note and an additional $100 million under a separate promissory note issued to Southern Company in November 2015.

On June 27, 2016, the Company received a capital contribution from Southern Company of $225 million, the proceeds of which were used to repay to Southern Company a portion of the promissory note issued in November 2015. As of December 31, 2016, the amount of outstanding promissory notes to Southern Company totaled $551 million.

Also, on December 14, 2016, the Company received a capital contribution from Southern Company of $400 million, the proceeds of which were used for general corporate purposes.

Other Obligations

In June 2016, the Company renewed a $10 million short-term note, which matures on June 30, 2017, bearing interest based on three-month LIBOR.

In September 2016, the Company entered into interest rate swaps to fix the variable interest rate on $900 million of the term loan entered into in March 2016.

In December 2016, the Company repaid $2.5 million of a $15 million short-term note, reducing the total short-term notes payable to $22.5 million.

Credit Rating Risk

At December 31, 2016, 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 have required or 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 for physical electricity purchases and sales, fuel transportation and storage, energy price risk management, and transmission. At December 31, 2016, the maximum amount of potential collateral requirements under these contracts at a rating of BBB and/or Baa2 or BBB- and/or Baa3 was not material. The maximum potential collateral requirements at a rating below BBB- and/or Baa3 equaled approximately $243 million.

Included in these amounts are certain agreements that could require collateral in the event that Alabama Power or Georgia Power 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 May 12, 2016, Fitch Ratings, Inc. (Fitch) downgraded the senior unsecured long-term debt rating of the Company to BBB+ from A- and revised the ratings outlook from negative to stable.

On January 10, 2017, S&P revised its consolidated credit rating outlook for Southern Company (including the Company) from negative to stable.

On February 6, 2017, Moody's placed the Company on a ratings review for potential downgrade. The Company's current rating for unsecured debt is Baa3.

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, foreign currency exchange 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 that include, but are not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

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To mitigate future exposure to a change in interest rates, the Company may enter into derivatives that have been designated as hedges. The weighted average interest rate on $891 million of long-term variable interest rate exposure at December 31, 2016 was 2.17%. If the Company sustained a 100 basis point change in interest rates for all long-term variable interest rate exposure, the change would affect annualized interest expense by approximately $9 million at January 1, 2017. See Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements for additional information.

To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, financial hedge contracts for natural gas purchases. The Company continues to manage retail fuel-hedging programs implemented per the guidelines of the Mississippi PSC and wholesale fuel-hedging programs under agreements with wholesale customers. The Company had no material change in market risk exposure for the year ended December 31, 2016 when compared to the year ended December 31, 2015.

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:

	2016 Changes	2015 Changes
	Fair Value (in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	$(47)	$ (45)
Contracts realized or settled	29	33
Current period changes(*)	11	(35)
Contracts outstanding at the end of the period, assets (liabilities), net	$(7)	$ (47)

(*) 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, all of which are natural gas swaps, for the years ended December 31 were as follows:

	2016	2015
	mmBtu Volume (in millions)	
Total hedge volume	36	32

For natural gas hedges, the weighted average swap contract cost above market prices was approximately $0.19 per mmBtu as of December 31, 2016 and $1.49 per mmBtu as of December 31, 2015. There were no options outstanding as of the reporting periods presented. The costs associated with natural gas hedges are recovered through the Company's ECMs.

At December 31, 2016 and 2015, 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 ECM clause.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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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 of the fair value hierarchy. See Note 9 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, 2016 were as follows:

	Fair Value Measurements December 31, 2016		
	Total	Maturity	
	Fair Value	Year 1	Years 2&3
	(in millions)		
Level 1	$ —	$ —	$ —
Level 2	(7)	(4)	(3)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$ (7)	$ (4)	$ (3)

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related 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 10 to the financial statements.

Capital Requirements and Contractual Obligations

Approximately $586 million will be required through December 31, 2017 to fund maturities of long-term debt, and $23 million will be required to fund maturities of short-term debt. See "Sources of Capital" herein for additional information.

The construction program of the Company is currently estimated to total $517 million for 2017, $241 million for 2018, $274 million for 2019, $305 million for 2020, and $230 million for 2021, which includes completion of the Kemper IGCC and post-in-service costs. Expenditures related to completion of the Kemper IGCC are currently estimated to be $254 million for 2017. These estimated program amounts also include capital expenditures covered under long-term service agreements. Estimated capital expenditures to comply with environmental statutes and regulations included in these program amounts are $11 million, $5 million, $24 million, $29 million, and $58 million for 2017, 2018, 2019, 2020, and 2021, respectively. These estimated environmental expenditures do not include potential compliance costs that may arise from the EPA's final rules and guidelines or future state plans that would limit CO_2 emissions from existing, new, modified, or reconstructed fossil-fuel-fired electric generating units. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" and "– Global Climate Issues" and – "Integrated Coal Gasification Combined Cycle" herein for additional information.

The Company also anticipates costs associated with closure and monitoring of ash ponds in accordance with the CCR Rule, which are reflected in 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 activities, are estimated to be $32 million, $11 million, $6 million, $6 million, and $9 million for the years 2017, 2018, 2019, 2020, and 2021, respectively. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; storm impacts; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in FERC rules and regulations; Mississippi PSC approvals; changes in the expected environmental compliance program; changes in legislation; the

cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital.
In addition, the construction program includes the development and construction of the Kemper IGCC, a first-of-a-kind technology, which may result in revised estimates during construction. The ability to control costs and avoid cost overruns during the development and construction of new facilities is subject to a number of factors, including, but not limited to, changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, sustaining nitrogen supply, contractor or supplier delay, non-performance under construction, operating, or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design

problems, start-up activities (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC).

See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information and further risks related to the estimated schedule and costs and rate recovery for the Kemper IGCC.

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 FERC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred stock dividends, unrecognized tax benefits, pension and other post-retirement benefit plans, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 10 to the financial statements for additional information.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Contractual Obligations
Contractual obligations at December 31, 2016 were as follows:

	2017	2018-2019	2020-2021	After 2021	Total
	(in millions)				
Long-term debt[(a)] —					
Principal	$626	$ 1,325	$ 270	$723	$2,944
Interest	98	141	100	598	937
Preferred stock dividends[(b)]	2	3	3	—	8
Financial derivative obligations[(c)]	6	4	—	—	10
Unrecognized tax benefits[(d)]	465	—	—	—	465
Operating leases [(e)]	2	1	1	—	4
Capital leases[(f)]	7	13	13	76	109
Purchase commitments —					
Capital[(g)]	480	508	506	—	1,494
Fuel[(h)]	290	320	184	251	1,045
Long-term service agreements[(i)]	15	75	48	244	382
Pension and other postretirement benefits plans[(j)]	7	15	—	—	22
Total	$1,998	$ 2,405	$ 1,125	$1,892	$7,420

(a) All amounts are reflected based on final maturity dates except for amounts related to certain pollution control revenue bonds. Long-term debt principal for 2017 includes $40 million of pollution control revenue bonds that are classified on the balance sheet at December 31, 2016 as short-term since they are variable rate demand obligations that are supported by short-term credit facilities; however, the final maturity date is in 2028. 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, 2017, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts (shown separately).

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

(c) For additional information, see Notes 1 and 10 to the financial statements.

(d) See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

(e) See Note 7 to the financial statements for additional information.

(f) Capital lease related to a 20-year nitrogen supply agreement for the Kemper IGCC. See Note 6 to the financial statements for additional information.

(g) The Company provides estimated capital expenditures for a five-year period, including capital expenditures associated with environmental regulations. At December 31, 2016, significant purchase commitments were outstanding in connection with the construction program. These amounts exclude capital expenditures covered under long-term service agreements, which are reflected separately. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" herein for additional information. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

(h) Includes commitments to purchase coal 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, 2016.

(i) Long-term service agreements include price escalation based on inflation indices.

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

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Cautionary Statement Regarding Forward-Looking Statements
The Company's 2016 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, customer and sales growth, economic conditions, 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 and postretirement benefit plans contributions, financing activities, completion of construction projects, filings with state and federal regulatory authorities, impact of the PATH Act, federal income tax benefits, estimated sales and purchases under power sale and purchase agreements, storm damage cost recovery and repairs, 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 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, including potential tax reform legislation, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries;
- 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, construction, and operation of facilities, which include the development and construction of generating facilities with designs that have not been finalized or previously constructed, including changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, sustaining nitrogen supply, contractor or supplier delay, non-performance under operating or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC);
- the ability to construct facilities in accordance with the requirements of permits and licenses, to satisfy any environmental performance standards and the requirements of tax credits and other incentives, and to integrate facilities into the Southern Company system upon completion of construction;
- investment performance of the Company's employee and retiree benefit plans;
- 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 ability to successfully operate generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
- actions related to cost recovery for the Kemper IGCC, including the ultimate impact of the 2015 decision of the Mississippi Supreme Court, the Mississippi PSC's December 2015 rate order, and related legal or regulatory proceedings, Mississippi PSC review of the prudence of Kemper IGCC costs and approval of further permanent rate

recovery plans, actions relating to proposed securitization, satisfaction of requirements to utilize grants, and the ultimate impact of the termination of the proposed sale of an interest in the Kemper IGCC to SMEPA;

- 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;

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Mississippi Power Company 2016 Annual Report

- 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 foreign 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.

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STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2016, 2015, and 2014
Mississippi Power Company 2016 Annual Report

	2016	2015	2014
	(in millions)		
Operating Revenues:			
Retail revenues	$859	$776	$795
Wholesale revenues, non-affiliates	261	270	323
Wholesale revenues, affiliates	26	76	107
Other revenues	17	16	18
Total operating revenues	1,163	1,138	1,243
Operating Expenses:			
Fuel	343	443	574
Purchased power, non-affiliates	5	5	18
Purchased power, affiliates	29	7	25
Other operations and maintenance	312	274	271
Depreciation and amortization	132	123	97
Taxes other than income taxes	109	94	79
Estimated loss on Kemper IGCC	428	365	868
Total operating expenses	1,358	1,311	1,932
Operating Loss	(195)	(173)	(689)
Other Income and (Expense):			
Allowance for equity funds used during construction	124	110	136
Interest expense, net of amounts capitalized	(74)	(7)	(45)
Other income (expense), net	(7)	(8)	(14)
Total other income and (expense)	43	95	77
Loss Before Income Taxes	(152)	(78)	(612)
Income taxes (benefit)	(104)	(72)	(285)
Net Loss	(48)	(6)	(327)
Dividends on Preferred Stock	2	2	2
Net Loss After Dividends on Preferred Stock	$(50)	$(8)	$(329)

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

STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2016, 2015, and 2014
Mississippi Power Company 2016 Annual Report

	2016	2015	2014
	(in millions)		
Net Loss	$(48)	$(6)	$(327)
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $1, $-, and $-, respectively	1	—	—
Reclassification adjustment for amounts included in net income, net of tax of $1, $1, and $1, respectively	1	1	1
Total other comprehensive income (loss)	2	1	1
Comprehensive Loss	$(46)	$(5)	$(326)

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

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STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2016, 2015, and 2014
Mississippi Power Company 2016 Annual Report

	2016	2015	2014
	(in millions)		
Operating Activities:			
Net loss	$(48)	$(6)	$(327)
Adjustments to reconcile net loss to net cash provided from operating activities —			
Depreciation and amortization, total	157	126	104
Deferred income taxes	(67)	777	145
Investment tax credits	—	(210)	(38)
Allowance for equity funds used during construction	(124)	(110)	(136)
Pension and postretirement funding	(47)	—	(33)
Regulatory assets associated with Kemper IGCC	(12)	(61)	(72)
Estimated loss on Kemper IGCC	428	365	868
Income taxes receivable, non-current	—	(544)	—
Other, net	(20)	8	22
Changes in certain current assets and liabilities —			
-Receivables	13	28	(22)
-Prepaid income taxes	39	(35)	(50)
-Other current assets	(8)	(18)	(6)
-Accounts payable	(14)	(34)	33
-Accrued taxes	14	(11)	39
-Over recovered regulatory clause revenues	(45)	96	(18)
-Mirror CWIP	—	(271)	180
-Customer liability associated with Kemper refunds	(73)	73	—
-Other current liabilities	36	—	46
Net cash provided from operating activities	229	173	735
Investing Activities:			
Property additions	(798)	(857)	(1,257)
Investment in restricted cash	—	—	(11)
Distribution of restricted cash	—	—	11
Construction payables	(26)	(9)	(50)
Government grant proceeds	137	—	—
Other investing activities	(10)	(40)	(33)
Net cash used for investing activities	(697)	(906)	(1,340)
Financing Activities:			
Proceeds —			
Capital contributions from parent company	627	277	451
Bonds — Other	—	—	23
Interest-bearing refundable deposit	—	—	125
Long-term debt issuance to parent company	200	275	220
Other long-term debt	1,200	—	250
Short-term borrowings	—	505	—
Redemptions —			
Short-term borrowings	(478)	(5)	—
Long-term debt to parent company	(225)	—	(220)
Bonds — Other	—	—	(34)
Senior notes	(300)	—	—

Other long-term debt	(425)	(350)	—
Return of capital	—	—	(220)
Other financing activities	(5)	(4)	(2)
Net cash provided from financing activities	594	698	593
Net Change in Cash and Cash Equivalents	126	(35)	(12)
Cash and Cash Equivalents at Beginning of Year	98	133	145
Cash and Cash Equivalents at End of Year	$224	$98	$133
Supplemental Cash Flow Information:			
Cash paid (received) during the period for —			
Interest (net of $49, $66, and $69 capitalized, respectively)	$50	$45	$7
Income taxes (net of refunds)	(97)	(33)	(379)
Noncash transactions —			
Accrued property additions at year-end	78	105	114
Issuance of promissory note to parent related to repayment of interest-bearing refundable deposits and accrued interest	—	301	—

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

BALANCE SHEETS
At December 31, 2016 and 2015
Mississippi Power Company 2016 Annual Report

Assets	2016	2015
	(in millions)	
Current Assets:		
Cash and cash equivalents	$224	$98
Receivables —		
Customer accounts receivable	29	26
Unbilled revenues	42	36
Income taxes receivable, current	544	20
Other accounts and notes receivable	14	10
Affiliated	15	20
Fossil fuel stock	100	104
Materials and supplies, current	76	75
Other regulatory assets, current	115	95
Prepaid income taxes	—	39
Other current assets	8	8
Total current assets	1,167	531
Property, Plant, and Equipment:		
In service	4,865	4,886
Less accumulated provision for depreciation	1,289	1,262
Plant in service, net of depreciation	3,576	3,624
Construction work in progress	2,545	2,254
Total property, plant, and equipment	6,121	5,878
Other Property and Investments	12	11
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	361	290
Other regulatory assets, deferred	518	525
Income taxes receivable, non-current	—	544
Other deferred charges and assets	56	61
Total deferred charges and other assets	935	1,420
Total Assets	$8,235	$7,840

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

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BALANCE SHEETS
At December 31, 2016 and 2015
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Liabilities and Stockholder's Equity	2016	2015
	(in millions)	
Current Liabilities:		
Securities due within one year —		
Parent	$551	$—
Other	78	728
Notes payable	23	500
Accounts payable —		
Affiliated	62	85
Other	135	135
Customer deposits	16	16
Accrued taxes	99	85
Unrecognized tax benefits, current	383	—
Accrued interest	46	18
Accrued compensation	42	37
Asset retirement obligations, current	32	22
Over recovered regulatory clause liabilities	51	96
Customer liability associated with Kemper refunds	1	73
Other current liabilities	19	41
Total current liabilities	1,538	1,836
Long-Term Debt (See accompanying statements)	2,424	1,886
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	756	762
Employee benefit obligations	115	153
Asset retirement obligations, deferred	146	154
Unrecognized tax benefits, deferred	—	368
Other cost of removal obligations	170	165
Other regulatory liabilities, deferred	84	79
Other deferred credits and liabilities	26	45
Total deferred credits and other liabilities	1,297	1,726
Total Liabilities	5,259	5,448
Cumulative Redeemable Preferred Stock (See accompanying statements)	33	33
Common Stockholder's Equity (See accompanying statements)	2,943	2,359
Total Liabilities and Stockholder's Equity	$8,235	$7,840

Commitments and Contingent Matters (See notes)
The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CAPITALIZATION
At December 31, 2016 and 2015
Mississippi Power Company 2016 Annual Report

	2016	2015	2016	2015
	(in millions)		(percent of total)	
Long-Term Debt:				
Long-term notes payable —				
2.35% due 2016	$ —	$ 300		