Financial Contents

Definitions

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 Mississippi Power's Kemper County energy facility

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

Atlantic Coast Pipeline
Atlantic Coast Pipeline, LLC, a joint venture to construct and operate a natural gas pipeline in which Southern Company Gas has a 5% ownership interest

Bechtel
Bechtel Power Corporation

CCR
Coal combustion residuals

Clean Air Act
Clean Air Act Amendments of 1990

CO_2
Carbon dioxide

COD
Commercial operation date

Contractor Settlement Agreement
The December 31, 2015 agreement between Westinghouse and the Vogtle Owners resolving disputes between the Vogtle Owners and the EPC Contractor under the Vogtle 3 and 4 Agreement

Cooperative Energy
Electric cooperative in Mississippi

CPCN
Certificate of public convenience and necessity

CWIP
Construction work in progress

Dalton Pipeline
A pipeline facility in Georgia in which Southern Company Gas has a 50% undivided ownership interest

DOE
U.S. Department of Energy

Eligible Project Costs
Certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the loan guarantee program established under Title XVII of the Energy Policy Act of 2005

EPA
U.S. Environmental Protection Agency

EPC Contractor
Westinghouse and its affiliate, WECTEC Global Project Services Inc.; the former engineering, procurement, and construction contractor for Plant Vogtle Units 3 and 4

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, the technology originally approved for Mississippi Power's Kemper County energy facility (Plant Ratcliffe)

Interim Assessment Agreement
Agreement entered into by the Vogtle Owners and the EPC Contractor to allow construction to continue after the EPC Contractor's bankruptcy filing

IRS
Internal Revenue Service

ITC
Investment tax credit

KWH
Kilowatt-hour

LIBOR
London Interbank Offered Rate

LIFO
Last-in, first-out

Loan Guarantee Agreement
Loan guarantee agreement entered into by Georgia Power with the DOE in 2014, under which the proceeds of borrowings may be used to reimburse Georgia Power for Eligible Project Costs incurred in connection with its construction of Plant Vogtle Units 3 and 4

LTSA
Long-term service agreement

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 financing costs associated with construction of the Kemper County energy facility, which were subsequently refunded to customers

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)

NCCR
Georgia Power's Nuclear Construction Cost Recovery

NDR
Alabama Power's Natural Disaster Reserve

New Jersey BPU
New Jersey Board of Public Utilities, the state regulatory agency for Elizabethtown Gas

Nicor Gas
Northern Illinois Gas Company, a wholly-owned subsidiary of Southern Company Gas

NO_X
Nitrogen oxide

NRC
U.S. Nuclear Regulatory Commission

OCI
Other comprehensive income

PennEast Pipeline
PennEast Pipeline Company, LLC, a joint venture to construct and operate a natural gas pipeline in which Southern Company Gas has a 20% ownership interest

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, as well as, for Southern Power, 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

SO_2
Sulfur dioxide

Southern Company Gas
Southern Company Gas and its subsidiaries

Southern Company Gas Capital
Southern Company Gas 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.

Definitions

Southern Power
Southern Power Company and its subsidiaries

Tax Reform Legislation
The Tax Cuts and Jobs Act, which was signed into law on December 22, 2017 and became effective on January 1, 2018

Toshiba
Toshiba Corporation, parent company of Westinghouse

Toshiba Guarantee
Certain payment obligations of the EPC Contractor guaranteed by Toshiba

traditional electric operating companies
Alabama Power, Georgia Power, Gulf Power, and Mississippi Power

VCM
Vogtle Construction Monitoring

Vogtle 3 and 4 Agreement
Agreement entered into with the EPC Contractor in 2008 by Georgia Power, acting for itself and as agent for the Vogtle Owners, pursuant to which the EPC Contractor agreed to design, engineer, procure, construct, and test Plant Vogtle Units 3 and 4

Vogtle Owners
Georgia Power, Oglethorpe Power Corporation, the Municipal Electric Authority of Georgia, and the City of Dalton, Georgia, an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light, and Sinking Fund Commissioners

Vogtle Services Agreement
The June 9, 2017 services agreement between the Vogtle Owners and the EPC Contractor, as amended and restated on July 20, 2017, for the EPC Contractor to transition construction management of Plant Vogtle Units 3 and 4 to Southern Nuclear and to provide ongoing design, engineering, and procurement services to Southern Nuclear

Westinghouse
Westinghouse Electric Company LLC

Reconciliation of Non-GAAP Financial Metric

Basic Earnings Per Share - Excluding Items
Basic earnings per share in 2017 of $0.84 plus an excluded $2.39 charge ($3.37 pre-tax) related to Mississippi Power's construction and suspension of the Kemper IGCC project, plus an excluded 2 cents (3 cents pre-tax) related to Gulf Power's write-down of its ownership in Plant Scherer Unit 3, plus an excluded 5 cents (4 cents pre-tax) related to the acquisition and integration of Southern Company Gas and the pending dispositions of Elizabethtown Gas and Elkton Gas, plus 6 cents (6 cents pre-tax) related to the Wholesale Gas Services business of Southern Company Gas, minus 6 cents (5 cents pre-tax) related to the additional AFUDC equity as a result of extending the schedule for the Kemper IGCC project, and minus 28 cents related to the net tax benefit as a result of the Tax Reform Legislation.

Basic earnings per share in 2016 of $2.57 plus an excluded 28-cent charge (45 cents pre-tax) related to Mississippi Power's construction and associated rate recovery of the Kemper IGCC project, plus an excluded 9 cents (13 cents pre-tax) related to the acquisition and integration of Southern Company Gas, PowerSecure International, Inc. and the 50% interest in Southern Natural Gas Company, L.L.C. (SNG), and minus 4 cents (3 cents pre-tax) related to the additional AFUDC equity as a result of extending the schedule for the Kemper IGCC project.

Basic earnings per share in 2015 of $2.60 plus an excluded 25-cent charge (40 cents pre-tax) related to Mississippi Power's construction of the Kemper IGCC project, plus an excluded 3 cents (5 cents pre-tax) related to the costs of the acquisition of Southern Company Gas, and plus an excluded MC Asset Recovery insurance settlement charge of 1 cent (1 cent pre-tax).

Basic earnings per share in 2014 of $2.19 plus an excluded 59-cent charge (97 cents pre-tax) related to Mississippi Power's construction of the Kemper IGCC project and plus an excluded 2 cents (3 cents pre-tax) related to the reversal of previously recognized revenues recorded in 2014 and 2013 and the recognition of carrying costs associated with the 2015 Mississippi Supreme Court decision which reversed the Mississippi PSC's March 2013 rate order related to the Kemper IGCC project.

Basic earnings per share in 2013 of $1.88 plus an excluded 83-cent charge ($1.35 pre-tax) related to Mississippi Power's construction of the Kemper IGCC project, plus an excluded 2-cent charge (3 cents pre-tax) related to the restructuring of a leveraged lease investment, and minus an excluded MC Asset Recovery insurance settlement of 2 cents (1 cent pre-tax).

For comparative purposes, Basic Earnings Per Share - Excluding Items in 2016 does not reflect any adjustments to exclude (1) Southern Company Gas earnings, net of acquisition and integration costs and Wholesale Gas Services (15 cents per share, 25 cents pre-tax), (2) acquisition debt financing costs related to the acquisition of Southern Company Gas (11 cents per share, 18 cents pre-tax), and (3) the impact of additional shares of common stock issued to finance a portion of the purchase price for the 50% interest in SNG (3 cents per share). These items were not contemplated in The Southern Company's February 2016 guidance and, therefore, were previously excluded in 2016.

The Southern Company's 2017 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, completion of announced acquisitions or dispositions, filings with state and federal regulatory authorities, impacts of the Tax Reform Legislation, federal and state 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 and regulations governing air, water, land, and protection of other natural resources, and also changes in tax and other laws and regulations to which The Southern Company and its subsidiaries are subject, as well as changes in application of existing laws and regulations;
- the uncertainty surrounding the recently enacted Tax Reform Legislation, including implementing regulations and IRS interpretations, actions that may be taken in response by regulatory authorities, and its impact, if any, on the credit ratings of The Southern Company and its subsidiaries;
- current and future litigation or regulatory investigations, proceedings, or inquiries;
- the effects, extent, and timing of the entry of additional competition in the markets in which The Southern Company's subsidiaries operate;
- variations in demand for electricity and natural gas, including those relating to weather, the general economy, 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;
- transmission constraints;
- 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 previously constructed, including changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction, 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;
- the ability to construct facilities in accordance with the requirements of permits and licenses (including satisfaction of NRC requirements), 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;
- 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;
- legal proceedings and regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals and NRC actions;
- litigation related to the Kemper County energy facility;
- 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;

Cautionary Statement Regarding Forward-Looking Statements

- potential business strategies, including acquisitions or dispositions of assets or businesses, including the proposed disposition by a wholly-owned subsidiary of Southern Company Gas of Elizabethtown Gas and Elkton Gas and the potential sale of a 33% equity interest in substantially all of Southern Power's solar assets, which cannot be assured to be completed or beneficial to The 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 and the possibility that costs related to the integration of The Southern Company and Southern Company Gas will be greater than expected;
- the ability of counterparties of The 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 physical attack and the threat of physical attacks;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in The 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 The 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;
- impairments of goodwill or long-lived assets;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Annual Report on Form 10-K for the year ended December 31, 2017) filed by The Southern Company from time to time with the SEC.

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

Available Information

The Southern Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2017 (Form 10-K), as well as other documents filed by The Southern Company pursuant to the Securities Exchange Act of 1934, as amended, are available electronically at http://www.sec.gov.

A copy of the Form 10-K as filed with the SEC will be provided without charge upon written request to the office of the Corporate Secretary. Requests for copies should be directed to the Corporate Secretary, 30 Ivan Allen Jr. Blvd., N.W., Atlanta, GA 30308.

The Southern Company (Southern Company or the Company) is a holding company that 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. The traditional electric operating companies are vertically integrated utilities that own generation, transmission, and distribution facilities.

Southern Company owns all of the common stock of Southern Power Company, which is also an operating public utility company. Southern Power develops, 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, which was acquired by Southern Company in July 2016, 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. On October 15, 2017, a subsidiary of Southern Company Gas entered into agreements for the sale of the assets of two of Southern Company Gas' natural gas distribution utilities, Elizabethtown Gas and Elkton Gas. Southern Company Gas is also involved in several other businesses that are complementary to the distribution of natural gas.

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 executive and advisory, general and design engineering, operations, purchasing, accounting, finance and treasury, legal, 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 optics services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases and energy-related funds and companies, and for other electric and natural gas products and services. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants and is currently managing construction of and 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 infrastructure, energy efficiency, and utility infrastructure.

Southern Company Common Stock and Dividend Information

The common stock of Southern Company is listed and traded on the New York Stock Exchange. The common stock is also traded on regional exchanges across the U.S. Dividends are payable at the discretion of the board of directors.

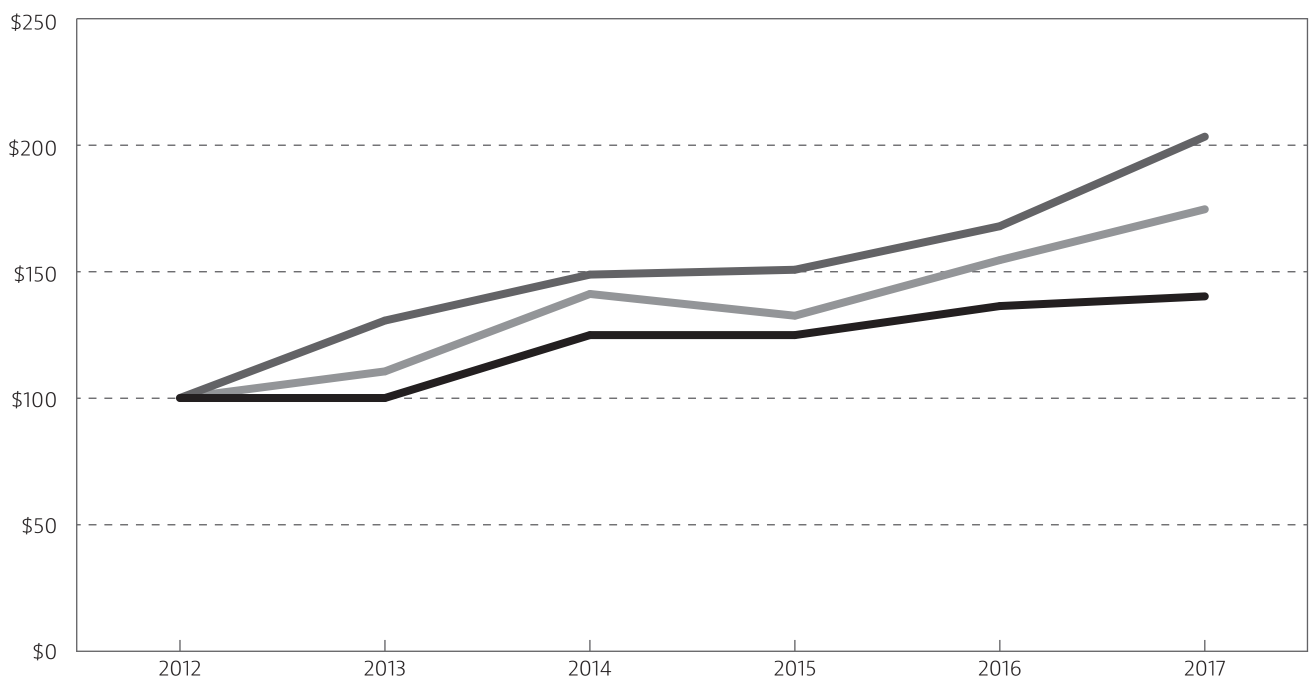
The high and low stock prices as reported on the New York Stock Exchange and the dividends on common stock declared by Southern Company for each quarter of the past two years were as follows:

2017	**High**	**Low**
First Quarter	$51.47	$47.57
Second Quarter	51.97	47.87
Third Quarter	50.80	46.71
Fourth Quarter	53.51	47.92
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

The dividend paid per share of Southern Company's common stock was 56.00¢ for the first quarter 2017 and 58.00¢ each for the second, third, and fourth quarters of 2017. In 2016, Southern Company paid a dividend per share of 54.25¢ for the first quarter and 56.00¢ each for the second, third, and fourth quarters.

Five-Year Cumulative Performance Graph

This performance graph compares the cumulative total shareholder return on the Company's common stock with the Standard & Poor's 500 index and the Philadelphia Utilities Index for the past five years. The graph assumes that $100 was invested on December 31, 2012 in the Company's common stock and each of the indices and that all dividends were reinvested. The stockholder return shown for the five-year historical period may not be indicative of future performance.



	2012	2013	2014	2015	2016	2017
Southern Company	100	100	126	126	138	142
S&P 500	100	132	151	153	171	208
Philadelphia Utilities Index	100	111	143	134	157	178

Southern Company and Subsidiary Companies 2017 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, 2017.

Deloitte & Touche LLP, 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, 2017, which is included herein.

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

Art P. Beattie
Executive Vice President and Chief Financial Officer

February 20, 2018

Report of Independent Registered Public Accounting Firm

To the stockholders and the Board of Directors of The Southern Company and Subsidiary Companies

Opinions on the Financial Statements and Internal Control over Financial Reporting

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, 2017 and 2016, 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, 2017, and the related notes (collectively referred to as the "financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the financial statements (pages 88 to 166) referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, 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, 2017, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by COSO.

Basis for Opinions

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 39). 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 are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. 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.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed 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 its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Deloitte & Touche LLP

Atlanta, Georgia
February 20, 2018

We have served as the Company's auditor since 2002.

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 businesses of the Southern Company system are electricity sales by the traditional electric operating companies and Southern Power and 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 develops, 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 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. See FUTURE EARNINGS POTENTIAL – "General" herein for information regarding agreements entered into by a wholly-owned subsidiary of Southern Company Gas to sell two of its natural gas distribution utilities.

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.

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" 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 create value through various transactions including acquisitions and sales of assets, development and construction of new generating facilities, and entry into PPAs primarily with investor-owned utilities, independent power producers, municipalities, electric cooperatives, and other load-serving entities, as well as commercial and industrial customers. In general, Southern Power has committed to the construction or acquisition of new generating capacity only after entering into or assuming long-term PPAs for the new facilities. Southern Power is also currently pursuing the sale of a portion of equity interests in its solar assets. See FUTURE EARNINGS POTENTIAL – "General" herein for additional information.

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.

Kemper County Energy Facility Status

The Kemper County energy facility was approved by the Mississippi PSC as an IGCC facility 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 (Cost Cap Exceptions). The combined cycle and associated common facilities portions of the Kemper County energy facility were placed in service in August 2014. In December 2015, the Mississippi PSC issued an order (In-Service Asset Rate Order), authorizing rates that provided for the recovery of approximately $126 million annually related to the assets previously placed in service.

On June 21, 2017, the Mississippi PSC stated its intent to issue an order (which occurred on July 6, 2017) directing Mississippi Power to pursue a settlement under which the Kemper County energy facility would be operated as a natural gas plant, rather than an IGCC plant, and address all issues associated with the Kemper County energy facility (Kemper Settlement Order). The Kemper Settlement Order established a new docket for the purposes of pursuing a global settlement of the related costs (Kemper Settlement Docket).

On June 28, 2017, Mississippi Power notified the Mississippi PSC that it would begin a process to suspend operations and start-up activities on the gasifier portion of the Kemper County energy facility, given the uncertainty as to its future. At the time of project suspension, the total cost estimate for the Kemper County energy facility was approximately $7.38 billion, including approximately $5.95 billion of costs subject to the construction cost cap, and was net of the $137 million in additional grants from the DOE received on April 8, 2016 (Additional DOE Grants). In the aggregate, Mississippi Power had incurred charges of $3.07 billion ($1.89 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through May 31, 2017. Given the Mississippi PSC's stated intent regarding no further rate increase for the Kemper County energy facility and the subsequent suspension, cost recovery of the gasifier portions became no longer probable; therefore, Mississippi Power recorded an additional charge to income in June 2017 of $2.8 billion ($2.0 billion after tax), which included estimated costs associated with the gasifier portions of the plant and lignite mine.

On February 6, 2018, the Mississippi PSC voted to approve a settlement agreement related to cost recovery for the Kemper County energy facility among Mississippi Power, the MPUS, and certain intervenors (Kemper Settlement Agreement). The Kemper Settlement Agreement provides for an annual revenue requirement of approximately $99.3 million for costs related to the Kemper County energy facility, which includes the impact of Tax Reform Legislation. The revenue requirement is based on (i) a fixed ROE for 2018 of 8.6%, excluding any performance adjustment, (ii) a ROE for 2019 calculated in accordance with Mississippi Power's Performance Evaluation Plan (PEP), excluding the performance adjustment, (iii) for future years, a performance-based ROE calculated pursuant to PEP, and (iv) amortization periods for the related regulatory assets and liabilities of eight years and six years, respectively. The revenue requirement also reflects a disallowance related to a portion of Mississippi Power's investment in the Kemper County energy facility requested for inclusion in rate base, which was recorded in the fourth quarter 2017 as an additional charge to income of approximately $78 million ($85 million net of accumulated depreciation of $7 million) pre-tax ($48 million after tax).

Under the Kemper Settlement Agreement, retail customer rates will reflect a reduction of approximately $26.8 million annually and include no recovery for costs associated with the gasifier portion of the Kemper County energy facility in 2018 or at any future date. On February 12, 2018, Mississippi Power made the required compliance filing with the Mississippi PSC. The Kemper Settlement Agreement also requires (i) the CPCN for the Kemper County energy facility to be modified to limit it to natural gas combined cycle operation and (ii) Mississippi Power to file a reserve margin plan with the Mississippi PSC by August 2018.

During the third and fourth quarters of 2017, Mississippi Power recorded charges to income of $242 million ($206 million after tax), including $164 million for ongoing project costs, estimated mine and gasifier-related costs, and certain termination costs during the suspension period prior to conclusion of the Kemper Settlement Docket, as well as the charge associated with the Kemper Settlement Agreement. Additional pre-tax cancellation costs, including mine and plant closure and contract termination costs, currently estimated at approximately $50 million to $100 million (excluding salvage), are expected to be incurred in 2018. Mississippi Power has begun efforts to dispose of or abandon the mine and gasifier-related assets.

Total pre-tax charges to income related to the Kemper County energy facility were $3.4 billion ($2.4 billion after tax) for the year ended December 31, 2017. In the aggregate, since the Kemper County energy facility project started, Mississippi Power has incurred charges of $6.2 billion ($4.1 billion after tax) through December 31, 2017.

As a result of the Mississippi PSC order on February 6, 2018, rate recovery for the Kemper County energy facility is resolved, subject to any future legal challenges.

See Note 3 to the financial statements under "Kemper County Energy Facility" for additional information.

Plant Vogtle Units 3 and 4 Status

In 2009, the Georgia PSC certified construction of Plant Vogtle Units 3 and 4. In 2012, the NRC issued the related combined construction and operating licenses, which allowed full construction of the two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities to begin. Until March 2017, construction on Plant Vogtle Units 3 and 4 continued under the Vogtle 3 and 4 Agreement, which was a substantially fixed price agreement. On March 29, 2017, the EPC Contractor filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code.

In connection with the EPC Contractor's bankruptcy filing, Georgia Power, acting for itself and as agent for the Vogtle Owners, entered into the Interim Assessment Agreement with the EPC Contractor to allow construction to continue. The Interim Assessment Agreement expired on July 27, 2017 when the Vogtle Services Agreement became effective. In August 2017, following completion of comprehensive cost to complete and cancellation cost assessments, Georgia Power filed its seventeenth VCM report with the Georgia PSC, which included a recommendation to continue construction of Plant Vogtle Units 3 and 4, with Southern Nuclear serving as project manager and Bechtel serving as the primary construction contractor. On December 21, 2017, the Georgia PSC approved Georgia Power's recommendation to continue construction.

Georgia Power expects Plant Vogtle Units 3 and 4 to be placed in service by November 2021 and November 2022, respectively. Georgia Power's revised capital cost forecast for its 45.7% proportionate share of Plant Vogtle Units 3 and 4 is $8.8 billion ($7.3 billion after reflecting the impact of payments received under a settlement agreement regarding the Toshiba Guarantee (Guarantee Settlement Agreement) and certain refunds to customers ordered by the Georgia PSC (Customer Refunds)). Georgia Power's CWIP balance for Plant Vogtle Units 3 and 4 was $3.3 billion at December 31, 2017, which is net of the Guarantee Settlement Agreement payments less the Customer Refunds. Georgia Power estimates that its financing costs for construction of Plant Vogtle Units 3 and 4 will total approximately $3.1 billion, of which $1.6 billion had been incurred through December 31, 2017.

See Note 3 to the financial statements under "Nuclear Construction" for additional information.

Earnings

Consolidated net income attributable to Southern Company was $842 million in 2017, a decrease of $1.6 billion, or 65.6%, from the prior year. The decrease was primarily due to pre-tax charges of $3.4 billion ($2.4 billion after tax) related to the Kemper IGCC at Mississippi Power. Also contributing to the change were increases of $240 million in net income from Southern Company Gas (excluding the impact of $111 million in additional expense related to the Tax Reform Legislation) reflecting the 12-month period in 2017 compared to the six-month period following the Merger closing on July 1, 2016, $264 million related to net tax benefits from the Tax Reform Legislation, higher retail electric revenues resulting from increases in base rates partially offset by milder weather and lower customer usage, and increases in renewable energy sales at Southern Power. These increases were partially offset by higher interest and depreciation and amortization.

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.

Basic EPS was $0.84 in 2017, $2.57 in 2016, and $2.60 in 2015. Diluted EPS, which factors in additional shares related to stock-based compensation, was $0.84 in 2017, $2.55 in 2016, and $2.59 in 2015. EPS for 2017 was negatively impacted by $0.04 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 $2.30 in 2017, $2.22 in 2016, and $2.15 in 2015. In January 2018, Southern Company declared a quarterly dividend of 58 cents per share. This is the 281st consecutive quarter that Southern Company has paid a dividend equal to or higher than the previous quarter. For 2017, the dividend payout ratio was 273% compared to 86% for 2016. The increase was due to a significant reduction in earnings resulting from charges related to the Kemper IGCC. See "Earnings" and RESULTS OF OPERATIONS – "Electricity Business – Estimated Loss on Kemper IGCC" herein and Note 3 to the financial statements under "Kemper County Energy Facility" for additional information.

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		
(in millions)	**2017**	2016	2015
Electricity business	**$ 878**	$2,571	$2,401
Gas business	**243**	114	—
Other business activities	**(279)**	(237)	(34)
Net Income	**$ 842**	$2,448	$2,367

Electricity Business

Southern Company's electric utilities generate and sell electricity to retail and wholesale customers.

A condensed statement of income for the electricity business follows:

	Amount	Increase (Decrease) from Prior Year	
(in millions)	**2017**	2017	2016
Electric operating revenues	**$18,540**	$ 599	$ 499
Fuel	**4,400**	39	(389)
Purchased power	**863**	113	105
Cost of other sales	**69**	11	58
Other operations and maintenance	**4,340**	(183)	231
Depreciation and amortization	**2,457**	224	213
Taxes other than income taxes	**1,063**	24	44
Estimated loss on Kemper IGCC	**3,362**	2,934	63
Total electric operating expenses	**16,554**	3,162	325
Operating income	**1,986**	(2,563)	174
Allowance for equity funds used during construction	**152**	(48)	(26)
Interest expense, net of amounts capitalized	**1,011**	80	157
Other income (expense), net	**(83)**	(8)	(43)
Income taxes	**82**	(1,009)	(235)
Net income	**962**	(1,690)	183
Less:			
Dividends on preferred and preference stock of subsidiaries	**38**	(7)	(9)
Net income attributable to noncontrolling interests	**46**	10	22
Net Income Attributable to Southern Company	**$ 878**	$(1,693)	$ 170

Electric Operating Revenues

Electric operating revenues for 2017 were $18.5 billion, reflecting a $599 million increase from 2016. Details of electric operating revenues were as follows:

	Amount	
(in millions)	**2017**	2016
Retail electric — prior year	**$15,234**	$14,987
Estimated change resulting from —		
Rates and pricing	**508**	427
Sales decline	**(71)**	(35)
Weather	**(281)**	153
Fuel and other cost recovery	**(60)**	(298)
Retail electric — current year	**15,330**	15,234
Wholesale electric revenues	**2,426**	1,926
Other electric revenues	**681**	698
Other revenues	**103**	83
Electric operating revenues	**$18,540**	$17,941
Percent change	**3.3%**	2.9%

Retail electric revenues increased $96 million, or 0.6%, in 2017 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 2017 was primarily due to a Rate RSE increase at Alabama Power effective in January 2017, the recovery of Plant Vogtle Units 3 and 4 construction financing costs under the NCCR tariff at Georgia Power, and an increase in retail base rates effective July 2017 at Gulf Power. See Note 3 to the financial statements under "Regulatory Matters – Gulf Power – Retail Base Rate Cases" for additional information.

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 County energy facility in-service assets, effective September 2015. These increases were partially offset by accruals in 2016 for expected refunds at Alabama Power and Georgia Power. See Note 3 to the financial statements under "Kemper County Energy Facility – Rate Recovery" for additional information.

See Note 3 to the financial statements under "Regulatory Matters – Alabama Power – Rate RSE" and " – Rate CNP Compliance" and "Nuclear Construction" 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 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. Energy 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 related to the energy. 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, transmission constraints, 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:

(in millions)	**2017**	2016	2015
Capacity and other	**$ 838**	$ 771	$ 875
Energy	**1,588**	1,155	923
Total	**$2,426**	$1,926	$1,798

In 2017, wholesale revenues increased $500 million, or 26.0%, as compared to the prior year due to a $433 million increase in energy revenues and a $67 million increase in capacity revenues, primarily at Southern Power. The increase in energy revenues was primarily due to increases in renewable energy sales arising from new solar and wind facilities and non-PPA revenues from short-term sales. The increase in capacity revenues was primarily due to a PPA related to new natural gas facilities and additional customer capacity requirements.

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, partially offset by a $104 million decrease in capacity revenues. The increase in energy revenues was primarily due to increases 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.

Other Electric Revenues

Other electric revenues decreased $17 million, or 2.4%, and increased $41 million, or 6.2%, in 2017 and 2016, respectively, as compared to the prior years. The 2017 decrease was primarily due to a $15 million decrease in open access transmission tariff revenues, primarily as a result of the expiration of long-term transmission services contracts at Georgia Power. 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, primarily attributable to LED conversions.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2017 and the percent change from the prior year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2017	**2017**	2016	**2017**	2016
	(in billions)				
Residential	**50.5**	**(5.3)%**	2.3%	**(0.3)%**	0.2%
Commercial	**52.3**	**(2.6)**	0.4	**(0.9)**	(1.0)
Industrial	**52.8**	**—**	(2.1)	**—**	(2.2)
Other	**0.9**	**(4.0)**	(1.7)	**(3.9)**	(1.7)
Total retail	**156.5**	**(2.6)**	0.2	**(0.4)%**	(1.0)%
Wholesale	**49.0**	**32.4**	21.4		
Total energy sales	**205.5**	**3.9%**	3.6%		

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 decreased 4.2 billion KWHs in 2017 as compared to the prior year. This decrease was primarily due to milder weather and decreased customer usage, partially offset by customer growth. Weather-adjusted residential KWH sales decreased primarily due to decreased customer usage resulting from an increase in penetration of energy-efficient residential appliances and an increase in multi-family housing, partially offset by customer growth. Weather-adjusted commercial KWH sales decreased primarily due to decreased customer usage resulting from customer initiatives in energy savings and an ongoing migration to the electronic commerce business model, partially offset by customer growth. Industrial KWH energy sales were flat primarily due to decreased sales in the paper, stone, clay, and glass, transportation, and chemicals sectors, offset by increased sales in the primary metals and textile sectors. Additionally, Hurricane Irma negatively impacted customer usage for all customer classes.

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.

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 $20 million, or 24.1%, in 2017 as compared to the prior year. The 2017 increase was primarily due to additional third party infrastructure services.

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 one of the largest expenses 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:

	2017	2016	2015
Total generation *(in billions of KWHs)*	**194**	188	187
Total purchased power *(in billions of KWHs)*	**20**	19	13
Sources of generation *(percent)* —			
Gas	**46**	46	46
Coal	**30**	33	34
Nuclear	**16**	16	16
Hydro	**2**	2	3
Other	**6**	3	1
Cost of fuel, generated *(in cents per net KWH)* —			
Gas	**2.79**	2.48	2.60
Coal	**2.81**	3.04	3.55
Nuclear	**0.79**	0.81	0.79
Average cost of fuel, generated *(in cents per net KWH)*	**2.44**	2.40	2.64
Average cost of purchased power *(in cents per net KWH)*(*)	**5.19**	4.81	6.11

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

In 2017, total fuel and purchased power expenses were $5.3 billion, an increase of $152 million, or 3.0%, as compared to the prior year. The increase was primarily the result of a $196 million increase in the average cost of fuel and purchased power primarily due to higher natural gas prices, partially offset by a $44 million net decrease in the volume of KWHs generated and purchased.

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 $650 million decrease in the average cost of fuel and purchased power primarily due to lower coal and natural gas prices, partially offset by a $366 million increase in the volume of KWHs generated and purchased.

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 2017, fuel expense was $4.4 billion, an increase of $39 million, or 0.9%, as compared to the prior year. The increase was primarily due to a 12.5% increase in the average cost of natural gas per KWH generated and a 2.8% increase in the volume of KWHs generated by natural gas, partially offset by a 7.9% decrease in the volume of KWHs generated by coal and a 7.6% decrease in the average cost of coal per KWH generated.

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.

Purchased Power

In 2017, purchased power expense was $863 million, an increase of $113 million, or 15.1%, as compared to the prior year. The increase was primarily due to a 7.9% increase in the average cost per KWH purchased, primarily as a result of higher natural gas prices, and a 5.0% increase in the volume of KWHs purchased.

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 45.6% increase in the volume of KWHs purchased, partially offset by a 21.3% decrease in the average cost per KWH purchased primarily as a result of lower natural gas prices.

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 $69 million and $58 million in 2017 and 2016, respectively. 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 decreased $183 million, or 4.0%, in 2017 as compared to the prior year. The decrease was primarily due to cost containment and modernization activities implemented at Georgia Power that contributed to decreases of $85 million in generation maintenance costs, $49 million in other employee compensation and benefits, $46 million in transmission and distribution overhead line maintenance, and $22 million in customer accounts, service, and sales costs. Other factors include a $40 million increase in gains from sales of assets at Georgia Power and a $34 million decrease in scheduled outage and maintenance costs at generation facilities. These decreases were partially offset by a $56 million increase associated with new facilities at Southern Power, a $37 million increase in transmission and distribution costs primarily due to vegetation management at Alabama Power, and $32.5 million resulting from the write-down of Gulf Power's ownership of Plant Scherer Unit 3 in accordance with a rate case settlement agreement approved by the Florida PSC on April 4, 2017 (2017 Rate Case Settlement Agreement).

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.

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 $224 million, or 10.0%, in 2017 as compared to the prior year. The increase reflects $203 million related to additional plant in service at the traditional electric operating companies and Southern Power and a $13 million increase in amortization related to environmental compliance at Mississippi Power. The increase was partially offset by a $34 million increase in the reductions in depreciation authorized in Gulf Power's 2013 rate case settlement approved by the Florida PSC as compared to the corresponding period in 2016.

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.

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 $24 million, or 2.3%, in 2017 as compared to the prior year primarily due to an increase in property taxes due to new facilities at Southern Power.

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.

Estimated Loss on Kemper IGCC

In 2017, 2016, and 2015, estimated probable losses on the Kemper IGCC of $3.4 billion, $428 million, and $365 million, respectively, were recorded at Southern Company. On June 28, 2017, Mississippi Power suspended the gasifier portion of the project and recorded a charge to earnings for the remaining $2.8 billion book value of the gasifier portion of the project. Prior to the suspension, Mississippi Power recorded losses for revisions of estimated costs expected to be incurred on construction of the Kemper IGCC in excess of the $2.88 billion cost cap established by the Mississippi PSC, net of $245 million of the Initial DOE Grants and excluding the Cost Cap Exceptions.

See Note 3 to the financial statements under "Kemper County Energy Facility" for additional information.

Allowance for Equity Funds Used During Construction

AFUDC equity decreased $48 million, or 24.0%, in 2017 as compared to the prior year primarily due to Mississippi Power's suspension of the Kemper IGCC project in June 2017.

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 County energy facility CWIP subject to AFUDC at Mississippi Power prior to the suspension of the gasifier portion of the project.

See Note 3 to the financial statements under "Kemper County Energy Facility" for additional information.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized increased $80 million, or 8.6%, in 2017 as compared to the prior year primarily due to an increase in average outstanding long-term debt, primarily at Southern Power and Georgia Power, and a $37 million decrease in interest capitalized, primarily at Southern Power and Mississippi Power, partially offset by a net reduction of $36 million following Mississippi Power's settlement with the IRS related to research and experimental deductions. See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

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 Cooperative Energy and the resulting reversal of accrued interest on related deposits.

See Note 6 to the financial statements for additional information.

Other Income (Expense), Net

Other income (expense), net decreased $8 million, or 10.7%, in 2017 as compared to the prior year primarily due to increases in charitable donations. The change also includes an increase of $159 million in currency losses arising from a translation of euro-denominated fixed-rate notes into U.S. dollars, fully offset by an equal change in gains on the foreign currency hedges that were reclassified from accumulated OCI into earnings at Southern Power.

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 and a $6 million decrease in wholesale operating fee revenue at Georgia Power.

Income Taxes

Income taxes decreased $1.0 billion, or 92.5%, in 2017 as compared to the prior year primarily due to $809 million in tax benefits related to estimated losses on the Kemper IGCC at Mississippi Power and $346 million in net tax benefits resulting from the Tax Reform Legislation.

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.

See Note 5 to the financial statements 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 statements 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	Increase (Decrease) from Prior Year
(in millions)	**2017**	**2017**
Operating revenues	**$3,920**	**$2,268**
Cost of natural gas	**1,601**	**988**
Cost of other sales	**29**	**19**
Other operations and maintenance	**940**	**417**
Depreciation and amortization	**501**	**263**
Taxes other than income taxes	**184**	**113**
Total operating expenses	**3,255**	**1,800**
Operating income	**665**	**468**
Earnings from equity method investments	**106**	**46**
Interest expense, net of amounts capitalized	**200**	**119**
Other income (expense), net	**39**	**25**
Income taxes	**367**	**291**
Net income	**$ 243**	**$ 129**

The changes in the table above for Southern Company Gas reflect the 12-month period in 2017 compared to the six-month period following the Merger closing on July 1, 2016. Additionally, earnings from equity method investments include Southern Company Gas' acquisition of a 50% equity interest in Southern Natural Gas Company, L.L.C. (SNG) completed in September 2016. See Note 12 to the financial statements under "Southern Company Gas" for additional information on Southern Company Gas' investment in SNG.

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 2017, the percentage of operating revenues and net income generated during the Heating Season (January through March and November through December) were 67.3% and 73.7%, respectively. 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. The 2017 net income generated during the Heating Season was significantly impacted by additional tax expense recorded in the fourth quarter resulting from the Tax Reform Legislation. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation" herein for additional information.

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 optics services within the Southeast.

On May 9, 2016, Southern Company acquired all of the outstanding stock of PowerSecure for 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	
(in millions)	**2017**	**2017**	2016
Operating revenues	**$ 571**	**$268**	$ 256
Cost of other sales	**415**	**223**	192
Other operations and maintenance	**201**	**7**	70
Depreciation and amortization	**52**	**21**	17
Taxes other than income taxes	**3**	**—**	1
Total operating expenses	**671**	**251**	280
Operating income (loss)	**(100)**	**17**	(24)
Interest expense	**483**	**178**	239
Other income (expense), net	**(3)**	**28**	(24)
Income taxes (benefit)	**(307)**	**(91)**	(84)
Net income (loss)	**$(279)**	**$ (42)**	$(203)

Operating Revenues

Southern Company's non-electric operating revenues for these other business activities increased $268 million, or 88.4%, in 2017 as compared to the prior year. The increase was primarily the result of the inclusion of PowerSecure results for the 12-month period in 2017 compared to eight months in 2016. 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 following the acquisition of PowerSecure.

Cost of Other Sales

Cost of other sales increased $223 million and $192 million in 2017 and 2016, respectively. These cost increases were primarily related to sales of products and services by PowerSecure, which was acquired on May 9, 2016.

Other Operations and Maintenance Expenses

Other operations and maintenance expenses for these other business activities increased $7 million, or 3.6%, in 2017 as compared to the prior year. The increase was primarily due to a $44 million increase as a result of the inclusion of PowerSecure results for the 12-month period in 2017 compared to eight months in 2016, partially offset by a $35 million decrease in parent company expenses related to the Merger and the acquisition of PowerSecure. 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 following the acquisition of PowerSecure and an increase in parent company expenses of $16 million related to the Merger and the acquisition of PowerSecure.

Interest Expense

Interest expense for these other business activities increased $178 million, or 58.4%, in 2017 as compared to the prior year primarily due to an increase in average outstanding long-term debt at the parent company. 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.

Other Income (Expense), Net

Other income (expense), net for these other business activities increased $28 million in 2017 as compared to the prior year. The increase was primarily due to $30 million of expenses incurred in 2016 associated with bridge financing for the Merger. 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 related to the bridge financing for the Merger.

Income Taxes (Benefit)

The income tax benefit for these other business activities increased $91 million, or 42.1%, in 2017 as compared to the prior year primarily as a result of pre-tax earnings (losses) and net tax benefits related to the Tax Reform Legislation. The income tax benefit for these other business activities increased $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.

See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation" herein and Note 5 to the financial statements for additional information.

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. As discussed further herein, in October 2017, a wholly-owned subsidiary of Southern Company Gas entered into agreements for the sale of the assets of two of its natural gas distribution utilities, Elizabethtown Gas and Elkton Gas, to South Jersey Industries, Inc.

The results of operations for the past three years are not necessarily indicative of Southern Company's 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. Plant Vogtle Units 3 and 4 construction and rate recovery are also major factors. In addition, the profitability of Southern Power's competitive wholesale business and successful additional investments in renewable and other energy projects are also major factors.

On December 22, 2017, the Tax Reform Legislation was signed into law and became effective on January 1, 2018, which among other things, reduces the federal corporate income tax rate to 21% and changes rates of depreciation and the business interest deduction. See "Income Tax Matters – Federal Tax Reform Legislation" and FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein and Notes 3 and 5 to the financial statements for additional information.

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, all of which could contribute to a net reduction in customer usage. 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 the pace of economic growth that 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 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 and disposition activities.

On October 15, 2017, a wholly-owned subsidiary of Southern Company Gas entered into agreements for the sale of the assets of two of its natural gas distribution utilities, Elizabethtown Gas and Elkton Gas, to South Jersey Industries, Inc. for a total cash purchase price of $1.7 billion. As of December 31, 2017, the net book value of the assets to be disposed of in the sale was approximately $1.3 billion, which includes approximately $0.5 billion of goodwill. The goodwill is not deductible for tax purposes and, as a result, a deferred tax liability has not yet been provided. Through the completion of the asset sales, Southern Company Gas intends to invest less than $0.1 billion in capital additions required for ordinary business operations of these assets. The completion of each asset sale is subject to the satisfaction or waiver of certain conditions, including, among other customary closing conditions, the receipt of required regulatory approvals, including the FERC, the Federal Communications Commission, the New Jersey BPU, and, with respect to the sale of Elkton Gas, the Maryland PSC. Southern Company Gas and South Jersey Industries, Inc. made joint filings on December 22, 2017 and January 16, 2018 with the New Jersey BPU and the Maryland PSC, respectively, requesting regulatory approval. The asset sales are expected to be completed by the end of the third quarter 2018.

In addition, Southern Power is pursuing the sale of a 33% equity interest in a newly-formed holding company that owns substantially all of Southern Power's solar assets, which, if successful, is expected to close in the middle of 2018.

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

Environmental Matters

The Southern Company system's operations are regulated by state and federal environmental agencies through a variety of laws and regulations governing air, water, land, and protection of other natural resources. The Southern Company system maintains a comprehensive environmental compliance strategy to assess upcoming requirements and compliance costs associated with these environmental laws and regulations. The costs, including capital expenditures and operations and maintenance costs, required to comply with environmental laws and regulations may impact future unit retirement and replacement decisions, results of operations, cash flows, and financial condition. Compliance costs may result from the installation of additional environmental controls, closure and monitoring of CCR facilities, unit retirements, and adding or changing fuel sources for certain existing units, as well as related upgrades to the transmission system. A major portion of these compliance costs are expected to be recovered through existing ratemaking provisions. The ultimate impact of the environmental laws and regulations discussed below will depend on various factors, such as state adoption and implementation of requirements, the availability and cost of any deployed control technology, and the outcome of pending and/or future legal challenges.

New or revised environmental laws and regulations could affect many areas of the traditional electric operating companies', Southern Power's, and the natural gas distribution utilities' operations. The impact of any such changes cannot be determined at this time. Environmental compliance costs 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. Further, increased 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. 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.

The Southern Company system's commitment to the environment has been demonstrated in many ways, including participating in partnerships resulting in approximately $126 million of funding that has restored or enhanced more than 1.7 million acres of habitat since 2003; the removal of more than 15 million pounds of trash and debris from waterways through the Renew Our Rivers program; a 21% reduction in surface water withdrawal from 2015 to 2016; reductions in SO_2 and NO_X air emissions of 95% and 85%, respectively, since 1990; the reduction of mercury air emissions of over 90% since 2005; and the Southern Company system's changing energy mix.

Through 2017, the traditional electric operating companies have invested approximately $12.9 billion in environmental capital retrofit projects to comply with environmental requirements, with annual totals of approximately $0.9 billion, $0.5 billion, and $0.9 billion for 2017, 2016, and 2015, respectively. Although the timing, requirements, and estimated costs could change as environmental laws and regulations are adopted or modified, as compliance plans are revised or updated, and as legal challenges to rules are initiated or completed, the Southern Company system's current compliance strategy estimates capital expenditures of $2.8 billion from 2018 through 2022, with annual totals of approximately $1.1 billion, $0.3 billion, $0.4 billion, $0.5 billion, and $0.5 billion for 2018, 2019, 2020, 2021, and 2022, respectively. These estimates do not include any potential compliance costs associated with the regulation of CO_2 emissions from fossil fuel-fired electric generating units. See "Global Climate Issues" herein for additional information. The Southern Company system also anticipates expenditures associated with ash pond closure and ground water monitoring under the Disposal of Coal Combustion Residuals from Electric Utilities 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.

Environmental Laws and Regulations

Air Quality

The EPA has set National Ambient Air Quality Standards (NAAQS) for six air pollutants (carbon monoxide, lead, nitrogen dioxide, ozone, particulate matter, and SO_2), which it reviews and revises periodically. Revisions to these standards can require additional emission controls, improvements in control efficiency, or fuel changes which can result in increased compliance and operational costs. NAAQS requirements can also adversely affect the siting of new facilities. In 2015, the EPA published a more stringent eight-hour ozone NAAQS. The EPA plans to complete designations for this rule by no later than April 30, 2018 and intends to designate an eight-county area within metropolitan Atlanta as nonattainment. No other areas within the Southern Company system's electric service territory have been or are anticipated to be designated nonattainment under the 2015 ozone NAAQS. In 2010, the EPA revised the NAAQS for SO_2, establishing a new one-hour standard, and is completing designations in multiple phases. The EPA has issued several rounds of area designations and no areas in the vicinity of Southern Company system-owned SO_2 sources have been designated nonattainment under the 2010 one-hour SO_2 NAAQS. However, final eight-hour ozone and SO_2 one-hour designations for certain areas are still pending and, if other areas are designated as nonattainment in the future, increased compliance costs could result.

In 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR) and its NO_X annual, NO_X seasonal, and SO_2 annual programs. CSAPR is an emissions trading program that addresses the impacts of the interstate transport of SO_2 and NO_X emissions from fossil fuel-fired power plants located in upwind states in the eastern half of the U.S. on air quality in downwind states. The Southern Company system has fossil fuel-fired generation in several states subject to these requirements. In October 2016, the EPA published a final rule that revised the CSAPR seasonal NO_X program, establishing more stringent NO_X emissions budgets in Alabama, Mississippi, and Texas. The EPA also removed North Carolina from the CSAPR NO_X seasonal program and completely removed Florida from all CSAPR programs. Georgia's seasonal NO_X budget remains unchanged. The outcome of ongoing CSAPR litigation, to which Mississippi Power is a party, could have an impact on the State of Mississippi's allowance allocations under the CSAPR seasonal NO_X program. Increases in either future fossil fuel-fired generation or the cost of CSAPR allowances could have a negative financial impact on results of operations for Southern Company.

The EPA finalized regional haze regulations in 2005 and 2017. These regulations require states, tribal governments, and various federal agencies to develop and implement plans to reduce pollutants that impair visibility and demonstrate reasonable progress toward the goal of restoring natural visibility conditions in certain areas, including national parks and wilderness areas. States must submit a revised state implementation plan (SIP) to the EPA by July 31, 2021, demonstrating reasonable progress towards achieving visibility improvement goals. State implementation of reasonable progress could require further reductions in SO_2 or NO_X emissions, which could result in increased compliance costs.

In 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 regulating excess emissions at industrial facilities, including electric generating facilities, during periods of startup, shut-down, or malfunction (SSM). The state excess emission rules provide necessary operational flexibility to affected units during periods of SSM and, if removed, could affect unit availability and result in increased operations and maintenance costs for the Southern Company system. The EPA has not yet responded to the SIP revisions proposed by states within the Southern Company system's traditional electric service territory.

Water Quality

In 2014, the EPA finalized requirements under Section 316(b) of the Clean Water Act (CWA) to regulate cooling water intake structures at existing power plants and manufacturing facilities in order to minimize their effects on fish and other aquatic life. The regulation requires plant-specific studies to determine applicable measures to protect organisms that either get caught on the intake screens (impingement) or are drawn into the cooling system (entrainment). The ultimate impact of this rule will depend on the outcome of these plant-specific studies and any additional protective measures required to be incorporated into each plant's National Pollutant Discharge Elimination System (NPDES) permit based on site-specific factors.

In 2015, the EPA finalized the steam electric effluent limitations guidelines (ELG) rule that set national standards for wastewater discharges from steam electric generating units. The rule prohibits effluent discharges of certain wastestreams and imposes stringent arsenic, mercury, selenium, and nitrate/nitrite limits on scrubber wastewater discharges. The revised technology-based limits and compliance dates may require extensive modifications to existing ash and wastewater management systems or the installation and operation of new ash and wastewater management systems. Compliance with the ELG rule is expected to require capital expenditures and increased operational costs primarily affecting the traditional electric operating companies' coal-fired electric generation. Compliance applicability dates range from November 1, 2018 to December 31, 2023 with state environmental agencies incorporating specific applicability dates in the NPDES permitting process based on information provided for each waste stream. The EPA has committed to a new rulemaking that could potentially revise the limitations and applicability dates of the ELG rule. The EPA expects to finalize this rulemaking in 2020.

In 2015, the EPA and the U.S. Army Corps of Engineers (Corps) jointly published a final rule that revised the regulatory definition of waters of the United States (WOTUS) for all CWA programs. The rule significantly expanded the scope of federal jurisdiction over waterbodies (such as rivers, streams, and canals), which could impact new generation projects and permitting and reporting requirements associated with the installation, expansion, and maintenance of transmission, distribution, and pipeline projects. On July 27, 2017, the EPA and the Corps proposed to rescind the 2015 WOTUS rule. The WOTUS rule has been stayed by the U.S. Court of Appeals for the Sixth Circuit since late 2015, but on January 22, 2018, the U.S. Supreme Court determined that federal district courts have jurisdiction over the pending challenges to the rule. On February 6, 2018, the EPA and the Corps published a final rule delaying implementation of the 2015 WOTUS rule to 2020.

Coal Combustion Residuals

In 2015, the EPA finalized non-hazardous solid waste regulations for the disposal of CCR, including coal ash and gypsum, in landfills and surface impoundments (CCR units) at active generating power plants. The CCR Rule requires CCR units to be evaluated against a set of performance criteria and potentially closed if minimum criteria are not met. Closure of existing CCR units could require installation of equipment and infrastructure to manage CCR in accordance with the rule. The EPA has announced plans to reconsider certain portions of the CCR Rule by no later than December 2019, which could result in changes to deadlines and corrective action requirements.

The EPA's reconsideration of the CCR Rule is due in part to a legislative development that impacts the potential oversight role of state agencies. Under the Water Infrastructure Improvements for the Nation Act, which became law in 2016, states are allowed to establish permit programs for implementing the CCR Rule. The Georgia Department of Natural Resources has incorporated the requirements of the CCR Rule into its solid waste regulations, which established additional requirements for all of Georgia Power's CCR units, and has requested that the EPA approve its state permitting program. The other states in the Southern Company system's electric service territory have not yet submitted plans to the EPA.

Based on cost estimates for closure and monitoring of ash ponds pursuant to the CCR Rule, Southern Company recorded AROs for each CCR unit in 2015. As further analysis is performed and closure details are developed, the traditional electric operating companies will continue to periodically update these cost estimates as necessary. 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 regarding Southern Company's AROs as of December 31, 2017.

Environmental Remediation

The Southern Company system must comply with environmental laws and regulations governing 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 Southern Company has recognized the estimated costs to clean up known impacted sites in its financial statements. 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 all 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 2015, the EPA published final rules limiting CO_2 emissions from new, modified, and reconstructed fossil fuel-fired electric generating units and guidelines for states to develop plans to meet EPA-mandated CO_2 emission performance standards for existing units (known as the Clean Power Plan or CPP). In February 2016, the U.S. Supreme Court granted a stay of the CPP, which will remain in effect through the resolution of litigation in the U.S. Court of Appeals for the District of Columbia challenging the legality of the CPP and any review by the U.S. Supreme Court. On March 28, 2017, the U.S. President signed an executive order directing agencies to review actions that potentially burden the development or use of domestically produced energy resources, including review of the CPP and other CO_2 emissions rules. On October 10, 2017, the EPA published a proposed rule to repeal the CPP and, on December 28, 2017, published an advanced notice of proposed rulemaking regarding a CPP replacement rule.

In 2015, parties to the United Nations Framework Convention on Climate Change, including the United States, adopted the Paris Agreement, which established a non-binding universal framework for addressing greenhouse gas (GHG) emissions based on nationally determined contributions. On June 1, 2017, the U.S. President announced that the United States would withdraw from the Paris Agreement and begin renegotiating its terms. The ultimate impact of this agreement or any renegotiated agreement depends on its implementation by participating countries.

Domestic GHG policies may emerge in the future requiring the United States to transition to a lower GHG emitting economy. The Southern Company system has transitioned from an electric generating mix of 71% coal and 11% natural gas in 2005 to 30% percent coal and 46% natural gas mix in 2017 and currently includes over 8,000 MWs of renewable projects. In addition, the Southern Company system has retired 4,226 MWs of coal- and oil-fired generating capacity since 2010 and converted 3,280 MWs of generating capacity from coal to natural gas since 2015. Southern Company Gas replaced 5,300 miles of bare steel and cast-iron pipe, resulting in removal of 2.5 million metric tons of GHG from its natural gas distribution system since 1998. Based on ownership or financial control of facilities, the Southern Company system's 2016 GHG emissions (CO_2 equivalent) were approximately 99 million metric tons, with 2017 emissions estimated at 96 million metric tons. This equates to a reduction of 27% between 2005 and 2016 and a preliminary estimate of 30% through 2017. To better represent GHG emission reductions, the Southern Company system is transitioning to a maximum emission baseline year of 2007 and a baseline calculation methodology consistent with the EPA's Greenhouse Gas Reporting Program methodology. On a preliminary basis, these baseline adjustments result in an estimated GHG emission reduction of 36% from 2007 through 2017.

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 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 and filed their response with the FERC in 2015.

In December 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. On May 17, 2017, the FERC accepted the traditional electric operating companies' and Southern Power's compliance filing 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.

On October 25, 2017, the FERC issued an order in response to the traditional electric operating companies' and Southern Power's June 29, 2017 triennial updated market power analysis. The FERC directed the traditional electric operating companies and Southern Power to show cause within 60 days why market-based rate authority should not be revoked in certain areas adjacent to the area presently under mitigation in accordance with the February 2, 2017 order or to provide a mitigation plan to further address market power concerns. On November 10, 2017, the traditional electric operating companies and Southern Power responded to the FERC and proposed to resolve matters by applying the alternative mitigation authorized by the February 2, 2017 order to the adjacent areas made the subject of the October 25, 2017 order.

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

Southern Company Gas

At December 31, 2017, Southern Company Gas' midstream operations business was involved in two gas pipeline construction projects, the Atlantic Coast Pipeline project and the PennEast Pipeline project, which received FERC approval in October 2017 and January 2018, respectively. Southern Company Gas' portion of the expected capital expenditures for these projects total approximately $586 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.

On August 1, 2017, the Dalton Pipeline was placed in service as authorized by the FERC and transportation service for customers commenced. See Note 4 to the financial statements for additional information.

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.

At December 31, 2016, Alabama Power's retail return exceeded the allowed WCE range which resulted in Alabama Power establishing a $73 million Rate RSE refund liability. In accordance with an Alabama PSC order issued on February 14, 2017, Alabama Power applied the full amount of the refund to reduce the under recovered balance of Rate CNP PPA as discussed further below.

Effective in January 2017, Rate RSE increased 4.48%, or $245 million annually. At December 31, 2017, Alabama Power's actual retail return was within the allowed WCE range. On December 1, 2017, Alabama Power made its required annual Rate RSE submission to the Alabama PSC of projected data for calendar year 2018. Projected earnings were within the specified range; therefore, retail rates under Rate RSE remained unchanged for 2018.

In conjunction with Rate RSE, Alabama Power has an established retail tariff that provides for an adjustment to customer billings to recognize the impact of a change in the statutory income tax rate. As a result of Tax Reform Legislation, the application of this tariff would reduce annual retail revenue by approximately $250 million over the remainder of 2018. The ultimate outcome of this matter cannot be determined at this time.

Rate CNP PPA

Alabama Power's retail rates, approved by the Alabama PSC, provide for adjustments under Rate CNP to recognize the placing of new generating facilities into retail service. Alabama Power may also recover retail costs associated with certificated PPAs under Rate CNP PPA. On March 7, 2017, 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, 2017 through March 31, 2018. No adjustment to Rate CNP PPA is expected in 2018.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, Alabama Power eliminated 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 utilized the full amount of its $73 million Rate RSE refund liability to reduce the amount of the Rate CNP PPA under recovery and reclassified 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 two to four 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 Rate CNP Compliance-related operations and maintenance expenses and depreciation generally will have no effect on net income.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, Alabama Power reclassified $36 million of its under recovered balance in Rate CNP Compliance 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 two to four years. Alabama Power's current depreciation study became effective January 1, 2017.

On December 5, 2017, the Alabama PSC issued a consent order that Alabama Power leave in effect for 2018 the factors associated with Alabama Power's compliance costs for the year 2017, with any under-collected amount for prior years deemed recovered before any current year amounts. Any under recovered amounts associated with 2018 will be reflected in the 2019 filing.

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. The regulatory asset will be 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 Laws and Regulations" herein for additional information regarding environmental regulations.

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 on certified project 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 a separate fuel cost recovery tariff. 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 in April 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, 2016 as follows: (1) traditional base tariff rates by approximately $49 million; (2) ECCR tariff by approximately $75 million; (3) DSM tariffs by approximately $3 million; and (4) MFF tariff by approximately $13 million, for a total increase in base revenues of approximately $140 million. There were no changes to these tariffs in 2017.

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 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 will refund to retail customers approximately $44 million in 2018, as approved by the Georgia PSC on January 16, 2018. In 2017, Georgia Power's retail ROE was within the allowed retail ROE range, subject to review and approval by the Georgia PSC.

On January 19, 2018, the Georgia PSC issued an order on the Tax Reform Legislation, which was amended on February 16, 2018 (Tax Order). In accordance with the Tax Order, Georgia Power is required to submit its analysis of the Tax Reform Legislation and related recommendations to address the related impacts on Georgia Power's cost of service and annual revenue requirements by March 6, 2018. 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 revisions to ELG for steam electric power plants and additional regulations of CCR and CO_2.

In July 2016, the Georgia PSC approved Georgia Power's triennial Integrated Resource Plan (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). In August 2016, the Plant Mitchell and Plant Kraft units were retired and 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 (REDI) 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.

In 2017, Georgia Power filed for and received certification for 510 MWs of REDI utility-scale PPAs for solar generation resources, which are expected to be in operation by the end of 2019. Georgia Power also filed for and received approval to develop several solar generation projects to fulfill the approved self-build capacity.

In the 2016 IRP, the Georgia PSC also approved recovery of costs up to $99 million through June 30, 2019 to preserve nuclear generation as an option at a future generation site in Stewart County, Georgia. On March 7, 2017, the Georgia PSC approved Georgia Power's decision to suspend work at the site due to changing economics, including lower load forecasts and fuel costs. The timing of recovery for costs incurred of approximately $50 million is expected to be determined by the Georgia PSC in a future Georgia Power rate case.

Storm Damage Recovery

Georgia Power is accruing $30 million annually through December 31, 2019, as provided in the 2013 ARP, for incremental operating and maintenance costs of damage from major storms to its transmission and distribution facilities. Hurricanes Irma and Matthew caused significant damage to Georgia Power's transmission and distribution facilities during September 2017 and October 2016, respectively. The incremental restoration costs related to these hurricanes deferred in Georgia Power's regulatory asset for storm damage totaled approximately $260 million. At December 31, 2017, the total balance in Georgia Power's regulatory asset related to storm damage was $333 million. The rate of storm damage cost recovery is expected to be adjusted as part of Georgia Power's next base rate case required to be filed by July 1, 2019. 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

On April 4, 2017, the Florida PSC approved the 2017 Rate Case Settlement Agreement among Gulf Power and three intervenors with respect to Gulf Power's request in 2016 to increase retail base rates. Among the terms of the 2017 Rate Case Settlement Agreement, Gulf Power increased rates effective with the first billing cycle in July 2017 to provide an annual overall net customer impact of approximately $54.3 million. The net customer impact consisted of a $62.0 million increase in annual base revenues, less an annual purchased power capacity cost recovery clause credit for certain wholesale revenues of approximately $8 million through December 2019. In addition, Gulf Power continued its authorized retail ROE midpoint (10.25%) and range (9.25% to 11.25%) and is deemed to have a maximum equity ratio of 52.5% for all retail regulatory purposes. Gulf Power also began amortizing the regulatory asset associated with the investment balances remaining after the retirement of Plant Smith Units 1 and 2 (357 MWs) over 15 years effective January 1, 2018 and implemented new depreciation rates effective January 1, 2018. The 2017 Rate Case Settlement Agreement also resulted in a $32.5 million write-down of Gulf Power's ownership of Plant Scherer Unit 3 (205 MWs), which was recorded in the first quarter 2017. The remaining issues related to the inclusion of Gulf Power's investment in Plant Scherer Unit 3 in retail rates have been resolved as a result of the 2017 Rate Case Settlement Agreement, including recoverability of certain costs associated with the ongoing ownership and operation of the unit through the environmental cost recovery clause.

The 2017 Rate Case Settlement Agreement set forth a process for addressing the revenue requirement effects of the Tax Reform Legislation through a prospective change to Gulf Power's base rates. Under the terms of the 2017 Rate Case Settlement Agreement, by March 1, 2018, Gulf Power must identify the revenue requirements impacts and defer them to a regulatory asset or regulatory liability to be considered for prospective application in a change to base rates in a limited scope proceeding before the Florida PSC. In lieu of this approach, on February 14, 2018, the parties to the 2017 Rate Case Settlement Agreement filed a new stipulation and settlement agreement (2018 Tax Reform Settlement Agreement) with the Florida PSC. If approved, the 2018 Tax Reform Settlement Agreement will result in annual reductions of $18.2 million to Gulf Power's base rates and $15.6 million to Gulf Power's environmental cost recovery rates effective beginning the first calendar month following approval.

The 2018 Tax Reform Settlement Agreement also provides for a one-time refund of $69.4 million for the retail portion of unprotected (not subject to normalization) deferred tax liabilities through Gulf Power's fuel cost recovery rate over the remainder of 2018. In addition, a limited scope proceeding to address the flow back of protected deferred tax liabilities will be initiated by May 1, 2018 and Gulf Power will record a regulatory liability for the related 2018 amounts eligible to be returned to customers consistent with IRS normalization principles. Unless otherwise agreed to by the parties to the 2018 Tax Reform Settlement Agreement, amounts recorded in this regulatory liability will be refunded to retail customers in 2019 through Gulf Power's fuel cost recovery rate.

If the 2018 Tax Reform Settlement Agreement is approved, the 2017 Rate Case Settlement Agreement will be amended to increase Gulf Power's maximum equity ratio from 52.5% to 53.5% for regulatory purposes.

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

Mississippi Power

On February 7, 2018, Mississippi Power revised its annual projected PEP filing for 2018 to reflect the impacts of the Tax Reform Legislation. The revised filing requests an increase of $26 million in annual revenues, based on a performance adjusted ROE of 9.33% and an increased equity ratio of 55%. The ultimate outcome of this matter cannot be determined at this time.

Southern Company Gas

The natural gas distribution utilities are subject to regulation and oversight by their respective state regulatory agencies for the rates charged to their customers and other matters. These agencies approve rates designed to provide 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 ROE.

The natural gas market for Atlanta Gas Light was deregulated in 1997. Accordingly, marketers, rather than a traditional utility, sell natural gas to end-use customers in Georgia and handle customer billing functions. Atlanta Gas Light earns revenue for its distribution services by charging rates to its customers based primarily on monthly fixed charges that are set by the Georgia PSC and adjusted periodically.

With the exception of Atlanta Gas Light, the natural gas distribution utilities are authorized by the relevant regulatory agencies in the states in which they serve to use natural gas cost recovery mechanisms that adjust rates to reflect changes in the wholesale cost of natural gas and ensure recovery of all costs prudently incurred in purchasing natural gas for customers. Natural gas cost recovery revenues are adjusted for differences in actual recoverable natural gas costs and amounts billed in current regulated rates. Changes in the billing factor will not have a significant effect on revenues or net income, but will affect cash flows. In addition to natural gas cost recovery mechanisms, there are 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 Note 1 to the financial statements under "Cost of Natural Gas" for additional information.

Regulatory Infrastructure Programs

Certain of Southern Company Gas' 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 nine to 10 years, with completion dates ranging from 2020 through 2025. The total expected investment under these programs for 2018 is $395 million.

Base Rate Cases

On January 31, 2018, the Illinois Commerce Commission approved a $137 million increase in Nicor Gas' annual base rate revenues, including $93 million related to the recovery of investments under Nicor Gas' infrastructure program, effective February 8, 2018, based on a ROE of 9.8%.

The Illinois Commerce Commission issued an order effective January 25, 2018 that requires utilities in the state to record the impacts of the Tax Reform Legislation, including the reduction in the corporate income tax rate to 21% and the impact of excess deferred income taxes, as a regulatory liability. On February 20, 2018, the Illinois Commerce Commission granted Nicor Gas' application for rehearing to file revised base rates and tariffs, which Nicor Gas expects to file by the end of the second quarter 2018.

On December 1, 2017, Atlanta Gas Light filed its 2018 annual rate adjustment with the Georgia PSC. If approved, Atlanta Gas Light's annual base rate revenues will increase by $22 million, effective June 1, 2018. Atlanta Gas Light will file a revised rate adjustment to incorporate the effects of the Tax Reform Legislation in the first quarter 2018. The Georgia PSC is expected to rule on the revised requested increase in the second quarter 2018.

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

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.

Kemper County Energy Facility

The Kemper County energy facility was approved by the Mississippi PSC as an IGCC facility in the 2010 CPCN proceedings, subject to a construction cost cap of $2.88 billion, net of $245 million of the Initial DOE Grants and excluding the Cost Cap Exceptions. The combined cycle and associated common facilities portions of the Kemper County energy facility were placed in service in August 2014. In December 2015, the Mississippi PSC issued the In-Service Asset Rate Order, authorizing rates that provided for the recovery of approximately $126 million annually related to the assets previously placed in service.

On June 21, 2017, the Mississippi PSC stated its intent to issue the Kemper Settlement Order (which occurred on July 6, 2017) directing Mississippi Power to pursue a settlement under which the Kemper County energy facility would be operated as a natural gas plant, rather than an IGCC plant, and address all issues associated with the Kemper County energy facility. The Kemper Settlement Order established the Kemper Settlement Docket for the purposes of pursuing a global settlement of the related costs.

On June 28, 2017, Mississippi Power notified the Mississippi PSC that it would begin a process to suspend operations and start-up activities on the gasifier portion of the Kemper County energy facility, given the uncertainty as to its future. At the time of project suspension, the total cost estimate for the Kemper County energy facility was approximately $7.38 billion, including approximately $5.95 billion of costs subject to the construction cost cap, and was net of the $137 million in Additional DOE Grants. In the aggregate, Mississippi Power had incurred charges of $3.07 billion ($1.89 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through May 31, 2017. Given the Mississippi PSC's stated intent regarding no further rate increase for the Kemper County energy facility and the subsequent suspension, cost recovery of the gasifier portions became no longer probable; therefore, Mississippi Power recorded an additional charge to income in June 2017 of $2.8 billion ($2.0 billion after tax), which included estimated costs associated with the gasifier portions of the plant and lignite mine.

On February 6, 2018, the Mississippi PSC voted to approve the Kemper Settlement Agreement related to cost recovery for the Kemper County energy facility among Mississippi Power, the MPUS, and certain intervenors. The Kemper Settlement Agreement provides for an annual revenue requirement of approximately $99.3 million for costs related to the Kemper County energy facility, which includes the impact of Tax Reform Legislation. The revenue requirement is based on (i) a fixed ROE for 2018 of 8.6%, excluding any performance adjustment, (ii) a ROE for 2019 calculated in accordance with PEP, excluding the performance adjustment, (iii) for future years, a performance-based ROE calculated pursuant to PEP, and (iv) amortization periods for the related regulatory assets and liabilities of eight years and six years, respectively. The revenue requirement also reflects a disallowance related to a portion of Mississippi Power's investment in the Kemper County energy facility requested for inclusion in rate base, which was recorded in the fourth quarter 2017 as an additional charge to income of approximately $78 million ($85 million net of accumulated depreciation of $7 million) pre-tax ($48 million after tax).

Under the Kemper Settlement Agreement, retail customer rates will reflect a reduction of approximately $26.8 million annually and include no recovery for costs associated with the gasifier portion of the Kemper County energy facility in 2018 or at any future date. On February 12, 2018, Mississippi Power made the required compliance filing with the Mississippi PSC. The Kemper Settlement Agreement also requires (i) the CPCN for the Kemper County energy facility to be modified to limit it to natural gas combined cycle operation and (ii) Mississippi Power to file a reserve margin plan with the Mississippi PSC by August 2018.

During the third and fourth quarters of 2017, Mississippi Power recorded charges to income of $242 million ($206 million after tax), including $164 million for ongoing project costs, estimated mine and gasifier-related costs, and certain termination costs during the suspension period prior to conclusion of the Kemper Settlement Docket, as well as the charge associated with the Kemper Settlement Agreement. Additional pre-tax cancellation costs, including mine and plant closure and contract termination costs, currently estimated at approximately $50 million to $100 million (excluding salvage), are expected to be incurred in 2018. Mississippi Power has begun efforts to dispose of or abandon the mine and gasifier-related assets.

Total pre-tax charges to income related to the Kemper County energy facility were $3.4 billion ($2.4 billion after tax) for the year ended December 31, 2017. In the aggregate, since the Kemper County energy facility project started, Mississippi Power has incurred charges of $6.2 billion ($4.1 billion after tax) through December 31, 2017.

As a result of the Mississippi PSC order on February 6, 2018, rate recovery for the Kemper County energy facility is resolved, subject to any future legal challenges.

See Note 3 to the financial statements under "Kemper County Energy Facility" 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. The individual plaintiff 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 County energy facility 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 County energy facility; 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 County energy facility in Mississippi; and seek attorney's fees, costs, and interest. The plaintiffs also seek an injunction to prevent any Kemper County energy facility costs from being charged to customers through electric rates. On June 23, 2017, the Circuit Court ruled in favor of motions by Southern Company and Mississippi Power and dismissed the case. On July 7, 2017, the plaintiffs filed notice of an appeal. Southern Company believes this legal challenge has no merit; however, an adverse outcome in this proceeding could have a material impact on Southern Company's results of operations, financial condition, and liquidity. Southern Company intends to vigorously defend itself in this matter and the ultimate outcome of this matter cannot be determined at this time.

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 related to the cancelled CO2 contract with Treetop and alleged fraudulent misrepresentation, fraudulent concealment, civil conspiracy, and breach of contract on the part of Mississippi Power, Southern Company, and SCS and sought compensatory damages of $100 million, as well as unspecified punitive damages. Southern Company, Mississippi Power, and SCS moved to compel arbitration pursuant to the terms of the CO2 contract, which the court granted on May 4, 2017. On June 28, 2017, Treetop and other related parties filed a claim for arbitration requesting $500 million in damages. On December 28, 2017, Mississippi Power reached a settlement agreement with Treetop and other related parties and the arbitration was dismissed.

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 $9.4 billion, $9.3 billion, $8.4 billion, $7.0 billion, and $6.9 billion for 2018, 2019, 2020, 2021, and 2022, respectively.

The largest construction project currently underway in the Southern Company system is Plant Vogtle Units 3 and 4 (45.7% ownership interest by Georgia Power in the two units, each with approximately 1,100 MWs). See Note 3 to the financial statements under "Nuclear Construction" for additional information. See Note 12 to the financial statements under "Southern Power" 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.

Nuclear Construction

Vogtle 3 and 4 Agreement and EPC Contractor Bankruptcy

In 2008, Georgia Power, acting for itself and as agent for the Vogtle Owners, entered into the 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. Under the Toshiba Guarantee, Toshiba guaranteed certain payment obligations of the EPC Contractor, including any liability of the EPC Contractor for abandonment of work. In the first quarter 2016, Westinghouse delivered to the Vogtle Owners a total of $920 million of letters of credit from financial institutions (Westinghouse Letters of Credit) to secure a portion of the EPC Contractor's potential obligations under the Vogtle 3 and 4 Agreement.

Subsequent to the EPC Contractor bankruptcy filing, a number of subcontractors to the EPC Contractor alleged non-payment by the EPC Contractor for amounts owed for work performed on Plant Vogtle Units 3 and 4. Georgia Power, acting for itself and as agent for the Vogtle Owners, has taken actions to remove liens filed by these subcontractors through the posting of surety bonds. Related to such liens, certain subcontractors have filed, and additional subcontractors may file, actions against the EPC Contractor and the Vogtle Owners to preserve their payment rights with respect to such claims. All amounts associated with the removal of subcontractor liens and other EPC Contractor pre-petition accounts payable have been paid or accrued as of December 31, 2017.

On June 9, 2017, Georgia Power and the other Vogtle Owners and Toshiba entered into the Guarantee Settlement Agreement. Pursuant to the Guarantee Settlement Agreement, Toshiba acknowledged the amount of its obligation was $3.68 billion (Guarantee Obligations), of which Georgia Power's proportionate share was approximately $1.7 billion. The Guarantee Settlement Agreement provided for a schedule of payments for the Guarantee Obligations beginning in October 2017 and continuing through January 2021. Toshiba made the first three payments as scheduled. On December 8, 2017, Georgia Power, the other Vogtle Owners, certain affiliates of the Municipal Electric Authority of Georgia (MEAG Power), and Toshiba entered into Amendment No. 1 to the Guarantee Settlement Agreement (Guarantee Settlement Agreement Amendment). The Guarantee Settlement Agreement Amendment provided that Toshiba's remaining payment obligations under the Guarantee Settlement Agreement were due and payable in full on December 15, 2017, which Toshiba satisfied on December 14, 2017. Pursuant to the Guarantee Settlement Agreement Amendment, Toshiba was deemed to be the owner of certain pre-petition bankruptcy claims of Georgia Power, the other Vogtle Owners, and certain affiliates of MEAG Power against Westinghouse, and Georgia Power and the other Vogtle Owners surrendered the Westinghouse Letters of Credit.

Additionally, on June 9, 2017, Georgia Power, acting for itself and as agent for the other Vogtle Owners, and the EPC Contractor entered into the Vogtle Services Agreement, which was amended and restated on July 20, 2017. On July 20, 2017, the bankruptcy court approved the EPC Contractor's motion seeking authorization to (i) enter into the Vogtle Services Agreement, (ii) assume and assign to the Vogtle Owners certain project-related contracts, (iii) join the Vogtle Owners as counterparties to certain assumed project-related contracts, and (iv) reject the Vogtle 3 and 4 Agreement. The Vogtle Services Agreement, and the EPC Contractor's rejection of the Vogtle 3 and 4 Agreement, became effective upon approval by the DOE on July 27, 2017. The Vogtle Services Agreement will continue until the start-up and testing of Plant Vogtle Units 3 and 4 are complete and electricity is generated and sold from both units. The Vogtle Services Agreement is terminable by the Vogtle Owners upon 30 days' written notice.

Effective October 23, 2017, Georgia Power, acting for itself and as agent for the other Vogtle Owners, entered into a construction completion agreement with Bechtel, whereby Bechtel will serve as the primary contractor for the remaining construction activities for Plant Vogtle Units 3 and 4 (Bechtel Agreement). Facility design and engineering remains the responsibility of the EPC Contractor under the Vogtle Services Agreement. The Bechtel Agreement is a cost reimbursable plus fee arrangement, whereby Bechtel will be reimbursed for actual costs plus a base fee and an at-risk fee, which is subject to adjustment based on Bechtel's performance against cost and schedule targets. Each Vogtle Owner is severally (not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to Bechtel under the Bechtel Agreement. The Vogtle Owners may terminate the Bechtel Agreement at any time for their convenience, provided that the Vogtle Owners will be required to pay amounts related to work performed prior to the termination (including the applicable portion of the base fee), certain termination-related costs, and, at certain stages of the work, the applicable portion of the at-risk fee. Bechtel may terminate the Bechtel Agreement under certain circumstances, including certain Vogtle Owner suspensions of work, certain breaches of the Bechtel Agreement by the Vogtle Owners, Vogtle Owner insolvency, and certain other events. Pursuant to the Loan Guarantee Agreement between Georgia Power and the DOE, Georgia Power is required to obtain the DOE's approval of the Bechtel Agreement prior to obtaining any further advances under the Loan Guarantee Agreement.

On November 2, 2017, the Vogtle Owners entered into an amendment to their joint ownership agreements for Plant Vogtle Units 3 and 4 (as amended, Vogtle Joint Ownership Agreements) to provide for, among other conditions, additional Vogtle Owner approval requirements. Pursuant to the Vogtle Joint Ownership Agreements, the holders of at least 90% of the ownership interests in Plant Vogtle Units 3 and

4 must vote to continue construction if certain adverse events occur, including (i) the bankruptcy of Toshiba; (ii) termination or rejection in bankruptcy of certain agreements, including the Vogtle Services Agreement or the Bechtel Agreement; (iii) the Georgia PSC or Georgia Power determines that any of Georgia Power's costs relating to the construction of Plant Vogtle Units 3 and 4 will not be recovered in retail rates because such costs are deemed unreasonable or imprudent; or (iv) an increase in the construction budget contained in the seventeenth VCM report of more than $1 billion or extension of the project schedule contained in the seventeenth VCM report of more than one year. In addition, pursuant to the Vogtle Joint Ownership Agreements, the required approval of holders of ownership interests in Plant Vogtle Units 3 and 4 is at least (i) 90% for a change of the primary construction contractor and (ii) 67% for material amendments to the Vogtle Services Agreement or agreements with Southern Nuclear or the primary construction contractor, including the Bechtel Agreement. The Vogtle Joint Ownership Agreements also confirm that the Vogtle Owners' sole recourse against Georgia Power or Southern Nuclear for any action or inaction in connection with their performance as agent for the Vogtle Owners is limited to removal of Georgia Power and/or Southern Nuclear as agent, except in cases of willful misconduct.

Regulatory Matters

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 up to the certified capital cost of $4.418 billion. As of December 31, 2017, Georgia Power had recovered approximately $1.6 billion of financing costs. On January 30, 2018, Georgia Power filed to decrease the NCCR tariff by approximately $50 million, effective April 1, 2018, pending Georgia PSC approval. The decrease reflects the payments received under the Guarantee Settlement Agreement, the Customer Refunds ordered by the Georgia PSC aggregating approximately $188 million, and the estimated effects of Tax Reform Legislation. The Customer Refunds were recognized as a regulatory liability as of December 31, 2017 and will be paid in three installments of $25 to each retail customer no later than the third quarter 2018.

Georgia Power is required to file semi-annual VCM reports with the Georgia PSC by February 28 and August 31 each year. In October 2013, in connection with the eighth VCM report, the Georgia PSC approved a stipulation (2013 Stipulation) between Georgia Power and the staff of the Georgia PSC to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate in accordance with the 2009 certification order until the completion of Plant Vogtle Unit 3, or earlier if deemed appropriate by the Georgia PSC and Georgia Power.

On December 20, 2016, the Georgia PSC voted to approve a settlement agreement (Vogtle Cost Settlement Agreement) resolving certain prudency matters in connection with the fifteenth VCM report. On December 21, 2017, the Georgia PSC voted to approve (and issued its related order on January 11, 2018) certain recommendations made by Georgia Power in the seventeenth VCM report and modifying the Vogtle Cost Settlement Agreement. The Vogtle Cost Settlement Agreement, as modified by the January 11, 2018 order, resolved the following regulatory matters related to Plant Vogtle Units 3 and 4: (i) none of the $3.3 billion of costs incurred through December 31, 2015 and reflected in the fourteenth VCM report should be disallowed from rate base on the basis of imprudence; (ii) the Contractor Settlement Agreement was reasonable and prudent and none of the amounts paid pursuant to the Contractor Settlement Agreement should be disallowed from rate base on the basis of imprudence; (iii) (a) capital costs incurred up to $5.680 billion would be presumed to be reasonable and prudent with the burden of proof on any party challenging such costs, (b) Georgia Power would have the burden to show that any capital costs above $5.680 billion were prudent, and (c) a revised capital cost forecast of $7.3 billion (after reflecting the impact of payments received under the Guarantee Settlement Agreement and Customer Refunds) is found reasonable; (iv) construction of Plant Vogtle Units 3 and 4 should be completed, with Southern Nuclear serving as project manager and Bechtel as primary contractor; (v) approved and deemed reasonable Georgia Power's revised schedule placing Plant Vogtle Units 3 and 4 in service in November 2021 and November 2022, respectively; (vi) confirmed that the revised cost forecast does not represent a cost cap and that prudence decisions on cost recovery will be made at a later date, consistent with applicable Georgia law; (vii) reduced the ROE used to calculate the NCCR tariff (a) from 10.95% (the ROE rate setting point authorized by the Georgia PSC in the 2013 ARP) to 10.00% effective January 1, 2016, (b) from 10.00% to 8.30%, effective January 1, 2020, and (c) from 8.30% to 5.30%, effective January 1, 2021 (provided that the ROE in no case will be less than Georgia Power's average cost of long-term debt); (viii) reduced the ROE used for AFUDC equity for Plant Vogtle Units 3 and 4 from 10.00% to Georgia Power's average cost of long-term debt, effective January 1, 2018; and (ix) agreed that upon Unit 3 reaching commercial operation, retail base rates would be adjusted to include carrying costs on those capital costs deemed prudent in the Vogtle Cost Settlement Agreement. The January 11, 2018 order also stated that if Plant Vogtle Units 3 and 4 are not commercially operational by June 1, 2021 and June 1, 2022, respectively, the ROE used to calculate the NCCR tariff will be further reduced by 10 basis points each month (but not lower than Georgia Power's average cost of long-term debt) until the respective unit is commercially operational. The ROE reductions negatively impacted earnings by approximately $20 million in 2016 and $25 million in 2017 and are estimated to have negative earnings impacts of approximately $120 million in 2018 and an aggregate of $585 million from 2019 to 2022. In its January 11, 2018 order, the Georgia PSC stated if other certain conditions and assumptions upon which Georgia Power's seventeenth VCM report are based do not materialize, both Georgia Power and the Georgia PSC reserve the right to reconsider the decision to continue construction.

On February 12, 2018, Georgia Interfaith Power & Light, Inc. and Partnership for Southern Equity, Inc. filed a petition appealing the Georgia PSC's January 11, 2018 order with the Fulton County Superior Court. Georgia Power believes the appeal has no merit; however, an adverse outcome in this appeal could have a material impact on Southern Company's results of operations, financial condition, and liquidity.

The IRS allocated PTCs to each of Plant Vogtle Units 3 and 4, which originally required the applicable unit to be placed in service before 2021. Under the Bipartisan Budget Act of 2018, Plant Vogtle Units 3 and 4 continue to qualify for PTCs. The nominal value of Georgia Power's portion of the PTCs is approximately $500 million per unit.

In its January 11, 2018 order, the Georgia PSC also approved $542 million of capital costs incurred during the seventeenth VCM reporting period (January 1, 2017 to June 30, 2017). The Georgia PSC has approved seventeen VCM reports covering the periods through June 30, 2017, including total construction capital costs incurred through that date of $4.4 billion. Georgia Power expects to file its eighteenth VCM report on February 28, 2018 requesting approval of approximately $450 million of construction capital costs (before payments received under the Guarantee Settlement Agreement and the Customer Refunds) incurred from July 1, 2017 through December 31, 2017. Georgia Power's CWIP balance for Plant Vogtle Units 3 and 4 was approximately $4.8 billion as of December 31, 2017, or $3.3 billion net of payments received under the Guarantee Settlement Agreement and the Customer Refunds.

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

Cost and Schedule

Georgia Power's approximate proportionate share of the remaining estimated capital cost to complete Plant Vogtle Units 3 and 4 with in service dates of November 2021 and November 2022, respectively, is as follows:

(in billions)	
Project capital cost forecast	$ 7.3
Net investment as of December 31, 2017	(3.4)
Remaining estimate to complete	**$ 3.9**

Note: Excludes financing costs capitalized through AFUDC and is net of payments received under the Guarantee Settlement Agreement and the Customer Refunds.

Georgia Power estimates that its financing costs for construction of Plant Vogtle Units 3 and 4 will total approximately $3.1 billion, of which $1.6 billion had been incurred through December 31, 2017.

As construction continues, challenges with management of contractors, subcontractors, and vendors, labor productivity and availability, fabrication, delivery, assembly, and installation of plant systems, structures, and components (some of which are based on new technology and have not yet operated in the global nuclear industry at this scale), or other issues could arise and change the projected schedule and estimated cost.

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. 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, 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.

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

Other Matters

As of December 31, 2017, Georgia Power had borrowed $2.6 billion related to Plant Vogtle Units 3 and 4 costs through the Loan Guarantee Agreement and a multi-advance credit facility among Georgia Power, the DOE, and the FFB, which provides for borrowings of up to $3.46 billion, subject to the satisfaction of certain conditions. On September 28, 2017, the DOE issued a conditional commitment to

Georgia Power for up to approximately $1.67 billion in additional guaranteed loans under the Loan Guarantee Agreement. This conditional commitment expires on June 30, 2018, subject to any further extension approved by the DOE. Final approval and issuance of these additional loan guarantees by the DOE cannot be assured and are subject to the negotiation of definitive agreements, completion of due diligence by the DOE, receipt of any necessary regulatory approvals, and satisfaction of other conditions. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information, including applicable covenants, events of default, mandatory prepayment events, and conditions to borrowing.

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

Income Tax Matters

Federal Tax Reform Legislation

On December 22, 2017, the Tax Reform Legislation was signed into law and became effective on January 1, 2018. The Tax Reform Legislation, among other things, reduces the federal corporate income tax rate to 21%, retains normalization provisions for public utility property and existing renewable energy incentives, and repeals the corporate alternative minimum tax.

For businesses other than regulated utilities, the Tax Reform Legislation allows 100% bonus depreciation of qualified property acquired and placed in service between September 28, 2017 and January 1, 2023 and phases down by 20% each year until completely phased out for qualified property placed in service after December 31, 2027. Further, the business interest deduction is limited to 30% of taxable income excluding interest, net operating loss (NOL) carryforwards, and depreciation and amortization through December 31, 2021, and thereafter to 30% of taxable income excluding interest and NOL carryforwards.

Regulated utility businesses, including the majority of the operations of the traditional electric operating companies and the natural gas distribution companies, can continue deducting all business interest expense and are not eligible for bonus depreciation on capital assets acquired and placed in service after September 27, 2017. Projects with binding contracts before September 28, 2017 and placed in service after September 27, 2017 remain eligible for bonus depreciation under the Protecting Americans from Tax Hikes (PATH) Act.

In addition, under the Tax Reform Legislation, NOLs generated after December 31, 2017 can no longer be carried back to previous tax years but can be carried forward indefinitely, with utilization limited to 80% of taxable income of the subsequent tax year. The projected reduction of the consolidated income tax liability resulting from the tax rate reduction also delays the expected utilization of existing tax credit carryforwards.

For the year ended December 31, 2017, implementation of the Tax Reform Legislation resulted in an estimated net tax benefit of $264 million, a $0.4 billion decrease in regulatory assets, and a $6.9 billion increase in regulatory liabilities, primarily due to the impact of the reduction of the corporate income tax rate on deferred tax assets and liabilities. Also, the OCI ending balance at December 31, 2017 includes $30 million of stranded excess deferred tax balances, which will be adjusted through retained earnings in subsequent periods.

The Tax Reform Legislation is subject to further interpretation and guidance from the IRS, as well as each respective state's adoption. In addition, the regulatory treatment of certain impacts of the Tax Reform Legislation is subject to the discretion of the FERC and relevant state regulatory bodies. On January 31, 2018, SCS, on behalf of the traditional electric operating companies, filed with the FERC a reduction to the open access transmission tariff charge for 2018 to reflect the revised federal corporate income tax rate. See Note 3 to the financial statements under "Regulatory Matters" for additional information regarding the traditional electric operating companies' and the natural gas distribution utilities' rate filings to reflect the impacts of the Tax Reform Legislation.

On February 9, 2018, the Bipartisan Budget Act of 2018 was signed into law. Included in the tax extenders portion of the law were provisions extending PTCs on advanced nuclear power facilities and ITCs on qualified fuel cells. A subsidiary of PowerSecure installed fuel cells in 2017 which are expected to qualify for approximately $80 million of ITCs; however, the impact of the related tax benefits would be substantially offset by additional required payments under the applicable purchase contracts. Should Southern Company have a NOL in 2018, all of these ITCs may not be fully realized in 2018. See Note 3 to the financial statements under "Nuclear Construction" for additional information on the PTCs relating to advanced nuclear power facilities.

See FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein and Note 5 to the financial statements under "Current and Deferred Income Taxes" for additional information.

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

Bonus Depreciation

Under the Tax Reform Legislation, projects with binding contracts prior to September 28, 2017 and placed in service after September 27, 2017 remain eligible for bonus depreciation under the PATH Act. The PATH Act allowed 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. Based on provisional estimates, bonus depreciation is expected to result in positive cash flows of approximately $870 million for the 2017 tax year and approximately $290 million for the 2018 tax year. Should Southern Company have a NOL in 2018, all of these cash flows may not be fully realized in 2018. All projected tax benefits previously received for bonus depreciation related to the Kemper IGCC were repaid in connection with third quarter 2017 estimated tax payments. Additionally, Southern Company will record an abandonment loss on its 2018 corporate income tax return, which may not be fully realized should Southern Company have a NOL in 2018. See Notes 3 and 5 to the financial statements under "Kemper County Energy Facility" and "Current and Deferred Income Taxes – Net Operating Loss," respectively, for additional information. The ultimate outcome of these matters cannot be determined at this time.

Tax Credits

The Tax Reform Legislation retained the renewable energy incentives that were included in the PATH Act. 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 allows for 100% PTC for wind projects that commenced construction in 2016; 80% PTC for wind projects that commenced construction in 2017; 60% PTC for wind projects that commence construction in 2018; and 40% PTC for wind projects that commence construction in 2019. Wind projects commencing construction after 2019 will not be entitled to any PTCs. 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 the utilization and amortization of credits and the tax benefit related to basis differences.

Southern Power

In September 2017, Southern Power began a legal entity reorganization of various direct and indirect subsidiaries that own and operate substantially all of its solar facilities, including certain subsidiaries owned in partnership with various third parties. The reorganization is expected to be substantially completed in the first quarter 2018 and is expected to result in estimated tax benefits totaling between $50 million and $55 million related to certain changes in state apportionment rates and net operating loss carryforward utilization that will be recorded in the first quarter 2018. Southern Power is pursuing the sale of a 33% equity interest in the newly-formed holding company owning these solar assets. 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 standards for air, water, land, and protection of other natural resources, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO2 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 or regulatory matters 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.

In 2016, the SEC began conducting a formal investigation of Southern Company and Mississippi Power concerning the estimated costs and expected in-service date of the Kemper County energy facility. On November 30, 2017, the SEC staff notified Southern Company that it had concluded its investigation with no recommended enforcement action.

Litigation

On January 20, 2017, a purported securities class action complaint was filed against Southern Company, certain of its officers, and certain former Mississippi Power 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, certain of its officers, and certain former Mississippi Power officers made materially false and misleading statements regarding the Kemper County energy facility 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. On June 12, 2017, the plaintiffs filed an amended complaint that provided additional detail about their claims, increased the purported class period by one day, and added certain other former Mississippi Power officers as defendants. On July 27, 2017, the defendants filed a motion to dismiss the plaintiffs' amended complaint with prejudice, to which the plaintiffs filed an opposition on September 11, 2017.

On February 27, 2017, Jean Vineyard filed a shareholder derivative lawsuit in the U.S. District Court for the Northern District of Georgia that names as defendants Southern Company, certain of its directors, certain of its officers, and certain former Mississippi Power officers. The complaint alleges that the defendants caused Southern Company to make false or misleading statements regarding the Kemper County energy facility cost and schedule. Further, the complaint alleges that the defendants were unjustly enriched and caused the waste of corporate assets. The plaintiff seeks to recover, on behalf of Southern Company, unspecified actual damages and, on her own behalf, attorneys' fees and costs in bringing the lawsuit. The plaintiff also seeks certain changes to Southern Company's corporate governance and internal processes. On March 27, 2017, the court deferred this lawsuit until 30 days after certain further action in the purported securities class action complaint discussed above.

On May 15, 2017, Helen E. Piper Survivor's Trust filed a shareholder derivative lawsuit in the Superior Court of Gwinnett County, State of Georgia and, on May 31, 2017, Judy Mesirov filed a shareholder derivative lawsuit in the U.S. District Court for the Northern District of Georgia. Each of these lawsuits names as defendants Southern Company, certain of its directors, certain of its officers, and certain former Mississippi Power officers. Each complaint alleges that the individual defendants, among other things, breached their fiduciary duties in connection with schedule delays and cost overruns associated with the construction of the Kemper County energy facility. Each complaint further alleges that the individual defendants authorized or failed to correct false and misleading statements regarding the Kemper County energy facility schedule and cost and failed to implement necessary internal controls to prevent harm to Southern Company. Each plaintiff seeks to recover, on behalf of Southern Company, unspecified actual damages and disgorgement of profits and, on its behalf, attorneys' fees and costs in bringing the lawsuit. Each plaintiff also seeks certain unspecified changes to Southern Company's corporate governance and internal processes. On August 15, 2017, these two shareholder derivative lawsuits were consolidated in the U.S. District Court for the Northern District of Georgia and the court deferred the consolidated case until 30 days after certain further action in the purported securities class action complaint discussed above.

Southern Company believes these legal challenges have no merit; however, an adverse outcome in any of 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, the ultimate outcome of which cannot be determined at this time.

Investments in Leveraged Leases

A subsidiary of Southern Holdings 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. See Note 1 to the financial statements under "Leveraged Leases" for additional information.

The ability of the lessees to make required payments to the Southern Holdings subsidiary is dependent on the operational performance of the assets. In the last six months of 2017, the financial and operational performance of one of the lessees and the associated generation assets has raised significant concerns about the short-term ability of the generation assets to produce cash flows sufficient to support ongoing operations and the lessee's contractual obligations and its ability to make the remaining semi-annual lease payments to the Southern Holdings subsidiary beginning in June 2018. These operational challenges may also impact the expected residual value of the assets at the end of the lease term in 2047. If the June 2018 (or any future) lease payment is not paid in full, the Southern Holdings subsidiary may be unable to make its corresponding payment to the holders of the underlying non-recourse debt related to the generation assets. Failure to make the required payment to the debtholders would represent an event of default that would give the debtholders the right to foreclose on, and take ownership of, the generation assets from the Southern Holdings subsidiary, in effect terminating the lease and resulting in the write-off of the related lease receivable which had a balance of approximately $86 million as of December 31, 2017. Southern Company has evaluated the recoverability of the lease receivable and the expected residual value of the generation assets at the end of the lease under various scenarios and has concluded that its investment in the leveraged lease is not impaired as of December 31, 2017. Southern Company will continue to monitor the operational performance of the underlying assets and evaluate the ability of the lessee to continue to make the required lease payments, including the lease payment due in June 2018. The ultimate outcome of this matter cannot be determined at this time.

Natural Gas Storage

A wholly-owned subsidiary of Southern Company Gas owns and operates a natural gas storage facility consisting of two salt dome caverns in Louisiana. Periodic integrity tests are required in accordance with rules of the Louisiana Department of Natural Resources (DNR). In August 2017, in connection with an ongoing integrity project, updated seismic mapping indicated the proximity of one of the caverns to the edge of the salt dome may be less than the required minimum and could result in Southern Company Gas retiring the cavern early. At December 31, 2017, the facility's property, plant, and equipment had a net book value of $112 million, of which the cavern itself represents approximately 20%. A potential early retirement of this cavern is dependent upon several factors including compliance with an order from the Louisiana DNR detailing the requirements to place the cavern back in service, which includes, among other things, obtaining core samples to determine the composition of the sheath surrounding the edge of the salt dome.

The cavern continues to maintain its pressures and overall structural integrity. Southern Company Gas intends to monitor the cavern and comply with the Louisiana DNR order through 2020 and place the cavern back in service in 2021. These events were considered in connection with Southern Company Gas' annual long-lived asset impairment analysis, which determined there was no impairment as of December 31, 2017. Any changes in results of monitoring activities, rates at which expiring capacity contracts are re-contracted, timing of placing the cavern back in service, or Louisiana DNR requirements could trigger impairment. Further, early retirement of the cavern could trigger impairment of other long-lived assets associated with the natural gas storage facility. The ultimate outcome of this matter cannot be determined at this time, but could have a significant impact on Southern Company's financial statements.

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 86% of Southern Company's total operating revenues for 2017, 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 County Energy Facility Rate Recovery

For periods prior to the second quarter 2017, significant accounting estimates included Kemper County energy facility estimated construction costs, project completion date, and rate recovery. Mississippi Power recorded total pre-tax charges to income related to the Kemper County energy facility of $428 million ($264 million after tax) in 2016, $365 million ($226 million after tax) in 2015, $868 million ($536 million after tax) in 2014, and $1.2 billion ($729 million after tax) in prior years.

As a result of the Mississippi PSC's June 21, 2017 stated intent to issue an order (which occurred on July 6, 2017) directing Mississippi Power to pursue a settlement under which the Kemper County energy facility would be operated as a natural gas plant rather than an IGCC plant, as well as Mississippi Power's June 28, 2017 suspension of the operation and start-up of the gasifier portion of the Kemper County energy facility, the estimated construction costs and project completion date are no longer considered significant accounting estimates.

Given the Mississippi PSC's stated intent regarding no further rate increase for the Kemper County energy facility and the subsequent suspension, cost recovery of the gasifier portions became no longer probable; therefore, Mississippi Power recorded an additional charge to income in June 2017 of $2.8 billion ($2.0 billion after tax), which included estimated costs associated with the gasifier portions of the plant and lignite mine. During the third and fourth quarters of 2017, Mississippi Power recorded charges to income of $242 million ($206 million after tax), including $164 million for ongoing project costs, estimated mine and gasifier-related costs, and certain termination costs during the suspension period prior to conclusion of the Kemper Settlement Docket, as well as a charge of $78 million associated with the Kemper Settlement Agreement.

In the aggregate, since the Kemper County energy facility project started, Mississippi Power has incurred charges of $6.20 billion ($4.14 billion after tax) through December 31, 2017. See Note 14 to the financial statements for additional information on the individual charges by quarter.

As a result of the Mississippi PSC order on February 6, 2018, rate recovery for the Kemper County energy facility is resolved, subject to any future legal challenges, and no longer represents a critical accounting estimate.

See Note 3 to the financial statements under "Kemper County Energy Facility" for additional information.

Accounting for Income Taxes

The consolidated income tax provision and deferred income tax assets and liabilities, as well as any unrecognized tax benefits and valuation allowances, require significant judgment and estimates. These estimates are supported by historical tax return data, reasonable projections of taxable income, and interpretations of applicable tax laws and regulations across multiple taxing jurisdictions. The effective tax rate reflects the statutory tax rates and calculated apportionments for the various states in which the Southern Company system operates.

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. Certain deductions and credits can be limited at the consolidated or combined level resulting in NOL and tax credit carryforwards that would not otherwise result on a stand-alone basis. Utilization of NOL and tax credit carryforwards and the assessment of valuation allowances are based on significant judgment and extensive analysis of the Company's current financial position and result of operations, including currently available information about future years, to estimate when future taxable income will be realized.

Current and deferred state income tax liabilities and assets are estimated based on laws of multiple states that determine the income to be apportioned to their jurisdictions. States utilize various formulas to calculate the apportionment of taxable income, primarily using sales, assets, or payroll within the jurisdiction compared to the consolidated totals. In addition, each state varies as to whether a stand-alone, combined, or unitary filing methodology is required. The calculation of deferred state taxes considers apportionment factors and filing methodologies that are expected to apply in future years. The apportionments and methodologies which are ultimately finalized in a manner inconsistent with expectations could have a material effect on Southern Company's financial statements.

Given the significant judgment involved in estimating NOL and tax credit carryforwards and multi-state apportionments for all subsidiaries, Southern Company considers state deferred income tax liabilities and assets to be critical accounting estimates.

Federal Tax Reform Legislation

Following the enactment of the Tax Reform Legislation, the SEC staff issued Staff Accounting Bulletin 118 – "Income Tax Accounting Implications of the Tax Cuts and Jobs Act" (SAB 118), which provides for a measurement period of up to one year from the enactment date to complete accounting under GAAP for the tax effects of the legislation. Due to the complex and comprehensive nature of the enacted tax law changes, and their application under GAAP, Southern Company considers all amounts recorded in the financial statements as a result of the Tax Reform Legislation to be "provisional" as discussed in SAB 118 and subject to revision. Southern Company is awaiting additional guidance from industry and income tax authorities in order to finalize its accounting. The ultimate impact of the Tax Reform Legislation on deferred income tax assets and liabilities and the related regulatory assets and liabilities cannot be determined at this time. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation" herein and Notes 3 and 5 to the financial statements under "Regulatory Matters" and "Current and Deferred Income Taxes," respectively, 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 and closure details are developed, the traditional electric operating companies will continue to periodically update these cost estimates as necessary. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations – Coal Combustion Residuals" herein and Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" and "Nuclear Decommissioning" for additional information.

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

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. Beginning in 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 2018	Increase/(Decrease) in Projected Obligation for Pension Plan at December 31, 2017	Increase/(Decrease) in Projected Obligation for Other Postretirement Benefit Plans at December 31, 2017
		(in millions)	
25 basis point change in discount rate	$40/$(38)	$504/$(476)	$68/$(65)
25 basis point change in salaries	$24/$(23)	$119/$(115)	$–/$–
25 basis point change in long-term return on plan assets	$33/$(33)	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, 2017.

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 $873 million at December 31, 2017.

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 and proposed dispositions.

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

Revenue

In 2014, the FASB issued ASC 606, *Revenue from Contracts with Customers* (ASC 606), 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 new standard 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.

Most of Southern Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity or natural gas without a defined contractual term, as well as longer-term contractual commitments, including PPAs and non-derivative natural gas asset management and optimization arrangements.

Southern Company has completed the evaluation of all revenue streams and determined that the adoption of ASC 606 will not change the current timing of revenue recognition for such transactions. Some revenue arrangements, such as certain PPAs, energy-related derivatives, and alternative revenue programs, are excluded from the scope of ASC 606 and, therefore, will be accounted for and disclosed or presented separately from revenues under ASC 606 on Southern Company's financial statements. Southern Company has concluded contributions in aid of construction are not in scope for ASC 606 and will continue to be accounted for as an offset to property, plant, and equipment.

The new standard is effective for reporting periods beginning after December 15, 2017. Southern Company applied the modified retrospective method of adoption effective January 1, 2018. Southern Company also utilized practical expedients which allowed it to apply the standard to open contracts at the date of adoption and to reflect the aggregate effect of all modifications when identifying performance obligations and allocating the transaction price for contracts modified before the effective date. Under the modified retrospective method of adoption, prior year reported results are not restated; however, a cumulative-effect adjustment to retained earnings at January 1, 2018 is recorded. In addition, quarterly disclosures will include comparative information on 2018 financial statement line items under current guidance. The adoption of ASC 606 did not result in a cumulative-effect adjustment.

Leases

In February 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 and Southern Company will adopt the new standard effective January 1, 2019.

Southern Company is currently implementing an information technology system along with the related changes to internal controls and accounting policies that will support the accounting for leases under ASU 2016–02. In addition, Southern Company has substantially completed a detailed inventory and analysis of its leases. In terms of rental charges and duration of contracts, the most significant leases relate to cellular towers and PPAs where certain of Southern Company's subsidiaries are the lessee and to land and outdoor lighting where certain of Southern Company's subsidiaries are the lessor. The traditional electric operating companies are currently analyzing pole attachment agreements, and a lease determination has not been made at this time. While Southern Company has not yet determined the ultimate impact, adoption of ASU 2016–02 is expected to have a significant impact on Southern Company's balance sheet.

Other

In November 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, and will be applied retrospectively to each period presented. Southern Company adopted ASU 2016–18 effective January 1, 2018 with no material impact on its financial statements.

On January 26, 2017, the FASB issued ASU No. 2017–04, *Intangibles – Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment* (ASU 2017–04). ASU 2017–04 removes the requirement to compare the implied fair value of goodwill with the carrying amount as part of Step 2 of the goodwill impairment test. Under the new standard, the goodwill impairment loss will be measured as the excess of a reporting unit's carrying amount over its fair value, not exceeding the total amount of goodwill allocated to that reporting unit, which may increase the frequency of goodwill impairment charges if a future goodwill impairment test does not pass the Step 1 evaluation. ASU 2017–04 is effective prospectively for periods beginning on or after December 15, 2019, with early adoption permitted. Southern Company adopted ASU 2017–04 effective January 1, 2018 with no impact on its financial statements.

On March 10, 2017, the FASB issued ASU No. 2017–07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (ASU 2017–07). ASU 2017–07 requires that an employer report the service cost component in the same line item or items as other compensation costs and requires the other components of net periodic pension and postretirement benefit costs to be separately presented in the income statement outside of income from operations. Additionally, only the service cost component is eligible for capitalization, when applicable. However, all cost components remain eligible for capitalization under FERC regulations. ASU 2017–07 will be applied retrospectively for the presentation of the service cost component and the other components of net periodic pension and postretirement benefit costs in the income statement. The capitalization of only the service cost component of net periodic pension and postretirement benefit costs in assets will be applied on a prospective basis. ASU 2017–07 is effective for periods beginning after December 15, 2017. The presentation changes required for net periodic pension and postretirement benefit costs will result in a decrease in Southern Company's operating income and an increase in other income for 2016 and 2017 and are expected to result in a decrease in operating income and an increase in other income for 2018. Southern Company adopted ASU 2017–07 effective January 1, 2018 with no material impact on its financial statements.

On August 28, 2017, the FASB issued ASU No. 2017–12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities* (ASU 2017–12), amending the hedge accounting recognition and presentation requirements. ASU 2017–12 makes more financial and non-financial hedging strategies eligible for hedge accounting, amends the related presentation and disclosure requirements, and simplifies hedge effectiveness assessment requirements. ASU 2017–12 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. Southern Company adopted ASU 2017–12 effective January 1, 2018 with no material impact on its financial statements.

FINANCIAL CONDITION AND LIQUIDITY

Overview

Earnings in all periods presented were negatively affected by charges associated with the Kemper IGCC; however, Southern Company's financial condition remained stable at December 31, 2017.

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, 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 2018 through 2020, 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 "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, 2017 as compared to December 31, 2016. No contributions to the qualified pension plan were made for the year ended December 31, 2017 and no mandatory contributions to the qualified pension plans are anticipated during 2018. 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 2017 totaled $6.4 billion, an increase of $1.5 billion from 2016. The increase in net cash provided from operating activities was primarily due to increases of $1.2 billion related to operating activities of Southern Company Gas, which was acquired on July 1, 2016, and $1.0 billion related to voluntary contributions to the qualified pension plan in 2016, partially offset by the timing of vendor payments. Net cash provided from operating activities in 2016 totaled $4.9 billion, a decrease of $1.4 billion from 2015. Significant changes in operating cash flow for 2016 as compared to 2015 included approximately $1.0 billion of voluntary contributions to the qualified pension plan in 2016 and a $1.2 billion increase in unutilized ITCs and PTCs.

Net cash used for investing activities in 2017, 2016, and 2015 totaled $7.2 billion, $20.0 billion, and $7.3 billion, respectively. The cash used for investing activities in 2017 was primarily due to the traditional electric operating companies' installation of equipment to comply with environmental standards and construction of electric generation, transmission, and distribution facilities, capital expenditures for Southern Company Gas' infrastructure replacement programs, and Southern Power's renewable acquisitions. 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 traditional electric operating companies' construction of electric generation, transmission, and distribution facilities and 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 was primarily due to the traditional electric operating companies' gross property additions for installation of equipment at electric generating facilities to comply with environmental standards and 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 $1.0 billion in 2017 primarily due to net issuances of long-term and short-term debt, partially offset by common stock dividend payments. 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 primarily 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. 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 2017 included decreases of $7.3 billion and $0.8 billion in accumulated deferred income taxes and deferred charges related to income taxes, respectively, and an increase of $7.0 billion in deferred credits related to income taxes primarily resulting from the impacts of the Tax Reform Legislation; an increase of $1.4 billion in total property, plant, and equipment primarily related to the traditional electric operating companies' installation of equipment to comply with environmental standards and construction of electric generation, transmission, and distribution facilities, Southern Company Gas' infrastructure replacement programs, and Southern Power's renewable acquisitions, largely offset by the $2.8 billion write-down of the gasification portions of the Kemper County energy facility and payments of $1.7 billion received by Georgia Power under the Guarantee Settlement Agreement; an increase of $3.1 billion in long-term debt (including amounts due within one year) primarily to fund the Southern Company system's continuous construction programs and for general corporate purposes; and a decrease of $1.1 billion in total stockholder's equity primarily related to the Kemper County energy facility charges, partially offset by the issuance of additional shares of common stock. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation" and "Financing Activities" herein and Note 3 to the financial statements under "Nuclear Construction" and "Kemper County Energy Facility" for additional information.

At the end of 2017, the market price of Southern Company's common stock was $48.09 per share (based on the closing price as reported on the New York Stock Exchange) and the book value was $23.99 per share, representing a market-to-book value ratio of 201%, compared to $49.19, $25.00, and 197%, respectively, at the end of 2016.

Southern Company's consolidated ratio of common equity to total capitalization plus short-term debt was 31.5% and 33.3% at December 31, 2017 and 2016, 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, borrowings from financial institutions, and debt and equity issuances in the capital markets. 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 and debt issuances in 2018, 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, borrowings from financial institutions, and equity contributions or loans from Southern Company. Southern Power also plans to utilize tax equity partnership contributions, as well as funds resulting from any potential sale of a 33% equity interest in a newly-formed holding company that owns substantially all of its solar assets, if completed. Southern Company Gas also plans to utilize the proceeds from the pending asset sales of two of its natural gas distribution utilities. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors. See FUTURE EARNINGS POTENTIAL – "General" herein for additional information.

In addition, in 2014, Georgia Power entered into the Loan Guarantee Agreement with the DOE, under which the proceeds of borrowings may be used to reimburse Georgia Power for Eligible Project Costs incurred in connection with its construction of Plant Vogtle Units 3 and 4. 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. As of December 31, 2017, Georgia Power had borrowed $2.6 billion under the FFB Credit Facility. On July 27, 2017, Georgia Power entered into an amendment to the Loan Guarantee Agreement, which provides that further advances are conditioned upon the DOE's approval of any agreements entered into in replacement of the Vogtle 3 and 4 Agreement and satisfaction of certain other conditions.

On September 28, 2017, the DOE issued a conditional commitment to Georgia Power for up to approximately $1.67 billion of additional guaranteed loans under the Loan Guarantee Agreement. This conditional commitment expires on June 30, 2018, subject to any further extension approved by the DOE. Final approval and issuance of these additional loan guarantees by the DOE cannot be assured and are subject to the negotiation of definitive agreements, completion of due diligence by the DOE, receipt of any necessary regulatory approvals, and satisfaction of other conditions. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information regarding the Loan Guarantee Agreement, including applicable covenants, events of default, mandatory prepayment events, and additional conditions to borrowing. Also see Note 3 to the financial statements under "Nuclear Construction" for additional information regarding Plant Vogtle Units 3 and 4.

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. 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.

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. Nicor Gas' commercial paper program supports its working capital needs as Nicor Gas is not permitted to make money pool loans to affiliates. All of the other Southern Company Gas subsidiaries benefit from Southern Company Gas Capital's commercial paper program.

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

As of December 31, 2017, Southern Company's current liabilities exceeded current assets by $3.5 billion, due to $3.9 billion of long-term debt that is due within one year (comprised of approximately $1.0 billion at the parent company, $0.9 billion at Georgia Power, $1.0 billion at Mississippi Power, $0.8 billion at Southern Power, and $0.2 billion at Southern Company Gas) and $2.4 billion of notes payable (comprised of approximately $0.6 billion at the parent company, $0.2 billion at Georgia Power, $0.1 billion at Southern Power, and $1.5 billion at Southern Company Gas). 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.

At December 31, 2017, Southern Company and its subsidiaries had approximately $2.1 billion of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2017 were as follows:

	Expires						Executable Term Loans		Expires Within One Year	
Company	2018	2019	2020	2022	Total	Unused	One Year	Two Years	Term Out	No Term Out
					(in millions)					
Southern Company[(a)]	$ —	$ —	$ —	$2,000	$2,000	$1,999	$ —	$—	$ —	$ —
Alabama Power	35	—	500	800	1,335	1,335	—	—	—	35
Georgia Power	—	—	—	1,750	1,750	1,732	—	—	—	—
Gulf Power	30	25	225	—	280	280	45	—	20	10
Mississippi Power	100	—	—	—	100	100	—	—	—	100
Southern Power Company[(b)]	—	—	—	750	750	728	—	—	—	—
Southern Company Gas[(c)]	—	—	—	1,900	1,900	1,890	—	—	—	—
Other	30	—	—	—	30	30	20	—	20	10
Southern Company Consolidated	$195	$25	$725	$7,200	$8,145	$8,094	$65	$—	$40	$155

(a) Represents the Southern Company parent entity.
(b) Does not include Southern Power's $120 million continuing letter of credit facility for standby letters of credit expiring in 2019, of which $19 million remains unused at December 31, 2017.
(c) Southern Company Gas, as the parent entity, guarantees the obligations of Southern Company Gas Capital, which is the borrower of $1.4 billion of these arrangements. Southern Company Gas' committed credit arrangements also include $500 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.

In May 2017, Southern Company, Alabama Power, Georgia Power, and Southern Power Company each amended certain of their multi-year credit arrangements, which, among other things, extended the maturity dates from 2020 to 2022. Southern Company and Southern Power Company increased their borrowing ability under these arrangements to $2.0 billion from $1.25 billion and to $750 million from $600 million, respectively. Southern Company also terminated its $1.0 billion facility maturing in 2018. Also in May 2017, Southern Company Gas Capital and Nicor Gas terminated their existing credit arrangements for $1.3 billion and $700 million, respectively, which were to mature in 2017 and 2018, and entered into a new multi-year credit arrangement with $1.4 billion and $500 million currently allocated to Southern Company Gas Capital and Nicor Gas, respectively, maturing in 2022. Pursuant to the new multi-year credit arrangement, the allocations between Southern Company Gas Capital and Nicor Gas may be adjusted. In September 2017, Alabama Power also amended its $500 million multi-year credit arrangement, which, among other things, extended the maturity date from 2018 to 2020.

In November 2017, Gulf Power amended $195 million of its multi-year credit arrangements to extend the maturity dates from 2017 and 2018 to 2020 and Mississippi Power amended its one-year credit arrangements in an aggregate amount of $100 million to extend the maturity dates from 2017 to 2018.

Most of these bank credit arrangements, as well as the term loan arrangements of Southern Company, Alabama Power, Georgia 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, 2017, 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 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 revenue bonds of the traditional electric operating companies outstanding requiring liquidity support as of December 31, 2017 was approximately $1.5 billion as compared to $1.9 billion at December 31, 2016. In addition, at December 31, 2017, the traditional electric operating companies had approximately $714 million of revenue bonds outstanding that were required to be remarketed within the next 12 months. Subsequent to December 31, 2017, $50 million of these revenue bonds of Mississippi Power which were in a long-term interest rate mode were remarketed in an index rate mode.

At December 31, 2017, Pivotal Utility Holdings, Inc., a subsidiary of Southern Company Gas, had $200 million of gas facility revenue bonds outstanding. The Elizabethtown Gas asset sale agreement requires that bonds representing $180 million of the total that are currently eligible for redemption at par be redeemed on or prior to consummation of the sale. See FUTURE EARNINGS POTENTIAL – "General" herein and Note 6 to the financial statements under "Gas Facility Revenue Bonds" for additional information.

Southern Company, the traditional electric operating companies (other than Mississippi Power), 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.

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, 2017:					
Commercial paper	**$1,832**	**1.8%**	**$2,117**	**1.3%**	**$2,946**
Short-term bank debt	**607**	**2.3%**	**555**	**2.1%**	**1,020**
Total	**$2,439**	**1.9%**	**$2,672**	**1.5%**	
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%	

(*) Average and maximum amounts are based upon daily balances during the 12-month periods ended December 31, 2017, 2016, and 2015.

In addition to the short-term borrowings of Southern Power Company included in the table above, at December 31, 2016 and 2015, Southern Power Company subsidiaries had 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. The Project Credit Facilities were fully repaid in January 2017. 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% and had total amounts outstanding of $209 million at a weighted average interest rate of 2.1% at December 31, 2016. For the year ended December 31, 2015, the Project Credit Facilities had a maximum amount outstanding of $137 million and an average amount outstanding of $13 million at a weighted average interest rate of 2.0% and had total amounts outstanding of $137 million at a weighted average interest rate of 2.0% at December 31, 2015.

Furthermore, in connection with the acquisition of a solar facility in July 2016, a subsidiary of Southern Power Company 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

During 2017, Southern Company issued approximately 14.6 million shares of common stock primarily through employee equity compensation plans and received proceeds of approximately $659 million.

In addition, during the second and third quarters of 2017, Southern Company issued a total of approximately 2.7 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 $134 million, net of $1.1 million in fees and commissions.

The following table outlines the long-term debt financing activities for Southern Company and its subsidiaries for the year ended December 31, 2017:

Company	Senior Note Issuances	Senior Note Maturities and Redemptions	Revenue Bond Issuances and Reofferings of Purchased Bonds	Revenue Bond Maturities, Redemptions, and Repurchases	Other Long-Term Debt Issuances	Other Long-Term Debt Redemptions and Maturities[a]
			(in millions)			
Southern Company[b]	$ 300	$ 400	$ —	$ —	$ 950	$ 400
Alabama Power	1,100	525	—	36	—	—
Georgia Power	1,350	450	65	65	370	17
Gulf Power	300	85	—	—	6	—
Mississippi Power	—	35	—	—	40	962
Southern Power	525	500	—	—	43	18
Southern Company Gas[c]	450	—	—	—	400	22
Other	—	—	—	—	—	15
Elimination[d]	—	—	—	—	(40)	(602)
Southern Company Consolidated	$4,025	$1,995	$65	$101	$1,769	$ 832

(a) Includes reductions in capital lease obligations resulting from cash payments under capital leases.
(b) Represents the Southern Company parent entity.
(c) The senior notes were issued by Southern Company Gas Capital and guaranteed by the Southern Company Gas parent entity. Other long-term debt issued represents first mortgage bonds issued by Nicor Gas.
(d) Includes intercompany loans from Southern Company to Mississippi Power and reductions in affiliate capital lease obligations at Georgia Power. These transactions are eliminated in Southern Company's Consolidated Financial Statements.

Except as otherwise described herein, Southern Company and its subsidiaries used the proceeds of debt issuances for their redemptions and maturities shown in the table above, to repay short-term indebtedness, and for general corporate purposes, including working capital and, for the subsidiaries, their continuous construction programs.

In March 2017, Southern Company repaid at maturity a $400 million 18-month floating rate bank loan.

In June 2017, Southern Company issued $500 million aggregate principal amount of Series 2017A 5.325% Junior Subordinated Notes due June 21, 2057 and $300 million aggregate principal amount of Series 2017A Floating Rate Senior Notes due September 30, 2020, which bear interest at a floating rate based on three-month LIBOR.

Also in June 2017, Southern Company entered into two $100 million aggregate principal amount short-term floating rate bank term loan agreements, which mature on June 21, 2018 and June 29, 2018 and bear interest based on one-month LIBOR.

In August 2017, Southern Company borrowed $250 million pursuant to a short-term uncommitted bank credit arrangement, which bears interest at a rate agreed upon by Southern Company and the bank from time to time and is payable on no less than 30 days' demand by the bank.

Also in August 2017, Southern Company repaid at maturity $400 million aggregate principal amount of Series 2014A 1.30% Senior Notes.

In November 2017, Southern Company issued $450 million aggregate principal amount of Series 2017B 5.25% Junior Subordinated Notes due December 1, 2077.

In September 2017, Alabama Power issued 10 million shares ($250 million aggregate stated capital) of 5.00% Class A Preferred Stock, Cumulative, Par Value $1 Per Share (Stated Capital $25 Per Share). The majority of the proceeds were used in October 2017 to redeem all 2 million shares ($50 million aggregate stated capital) of Alabama Power's 6.50% Series Preference Stock, 6 million shares ($150 million aggregate stated capital) of Alabama Power's 6.45% Series Preference Stock, and 1.52 million shares ($38 million aggregate stated capital) of Alabama Power's 5.83% Class A Preferred Stock.

In June 2017, Georgia Power entered into two short-term floating rate bank loans in aggregate principal amounts of $50 million and $150 million, with maturity dates of December 1, 2017 and May 31, 2018, respectively, and one long-term floating rate bank loan of $100 million, with a maturity date of June 28, 2018, which was amended in August 2017 to extend the maturity date to October 26, 2018. These loans bear interest based on one-month LIBOR. Also in June 2017, Georgia Power borrowed $500 million pursuant to a short-term uncommitted bank credit arrangement, which bears interest at a rate agreed upon by Georgia Power and the bank from time to time and is payable on no less than 30 days' demand by the bank.

In August 2017, Georgia Power repaid its $50 million floating rate bank loan due December 1, 2017 and $250 million of the $500 million aggregate principal amount outstanding pursuant to its uncommitted bank credit arrangement. In December 2017, Georgia Power repaid the remaining $250 million aggregate principal amount outstanding pursuant to its uncommitted bank credit arrangement.

Subsequent to December 31, 2017, Georgia Power repaid its outstanding $150 million and $100 million floating rate bank loans due May 31, 2018 and October 26, 2018, respectively.

As reflected in the table above under other long-term debt issuances, in September 2017, Georgia Power also issued $270 million aggregate principal amount of Series 2017A 5.00% Junior Subordinated Notes due October 1, 2077. The proceeds were used to redeem all 1.8 million shares ($45 million aggregate liquidation amount) of Georgia Power's 6.125% Series Class A Preferred Stock and 2.25 million shares ($225 million aggregate liquidation amount) of Georgia Power's 6.50% Series 2007A Preference Stock.

In March 2017, Gulf Power extended the maturity of its $100 million short-term floating rate bank loan bearing interest based on one-month LIBOR from April 2017 to October 2017 and subsequently repaid the loan in May 2017.

A portion of the proceeds of Gulf Power's senior note issuances was used in June 2017 to redeem 550,000 shares ($55 million aggregate liquidation amount) of Gulf Power's 6.00% Series Preference Stock, 450,000 shares ($45 million aggregate liquidation amount) of Gulf Power's Series 2007A 6.45% Preference Stock, and 500,000 shares ($50 million aggregate liquidation amount) of Gulf Power's Series 2013A 5.60% Preference Stock.

In June 2017, Mississippi Power prepaid $300 million of the outstanding principal amount under its $1.2 billion unsecured term loan, which matures on March 30, 2018.

In September 2017, Southern Power amended its $60 million aggregate principal amount floating rate term loan to, among other things, increase the aggregate principal amount to $100 million and extend the maturity date from September 2017 to October 2018.

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, 2017, 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, and construction of new generation at Plant Vogtle Units 3 and 4.

The maximum potential collateral requirements under these contracts at December 31, 2017 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB and/or Baa2	$ 40
At BBB- and/or Baa3	$ 665
At BB+ and/or Ba1(*)	$ 2,390

(*) Any additional credit rating downgrades at or below BB- and/or Ba3 could increase collateral requirements up to an additional $38 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 March 1, 2017, Moody's downgraded the senior unsecured debt rating of Mississippi Power to Ba1 from Baa3.

On March 20, 2017, Moody's revised its rating outlook for Georgia Power from stable to negative.

On March 24, 2017, S&P revised its consolidated credit rating outlook for Southern Company and its subsidiaries (including the traditional electric operating companies, Southern Power, Southern Company Gas, Southern Company Gas Capital, and Nicor Gas) from stable to negative.

On March 30, 2017, Fitch Ratings, Inc. placed the ratings of Southern Company, Georgia Power, and Mississippi Power on rating watch negative.

On June 22, 2017, Moody's placed the ratings of Mississippi Power on review for downgrade. On September 21, 2017, Moody's revised its rating outlook for Mississippi Power from under review to stable.

On January 19, 2018, Moody's revised its rating outlooks for Southern Company and Alabama Power from stable to negative.

While it is unclear how the credit rating agencies, the FERC, and relevant state regulatory bodies may respond to the Tax Reform Legislation, certain financial metrics, such as the funds from operations to debt percentage, used by the credit rating agencies to assess Southern Company and its subsidiaries may be negatively impacted. Absent actions by Southern Company and its subsidiaries to mitigate the resulting impacts, which, among other alternatives, could include adjusting capital structure and/or monetizing regulatory assets, the credit ratings of Southern Company and certain of its subsidiaries could be negatively affected. See Note 3 to the financial statements for additional information related to state PSC or other regulatory agency actions related to the Tax Reform Legislation.

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. Southern Company Gas' wholesale gas operations use various contracts in its commercial activities that generally meet the definition of derivatives. For the traditional electric operating companies, Southern Power, and Southern Company Gas' other businesses, 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.

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, 2017 have a notional amount of $3.7 billion and are intended to mitigate interest rate volatility related to existing fixed and floating rate obligations. The weighted average interest rate on $6.3 billion of long-term variable interest rate exposure at December 31, 2017 was 2.43%. 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 December 31, 2017. See Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements for additional information.

Southern Power Company had foreign currency denominated debt of €1.1 billion at December 31, 2017. Southern Power Company has mitigated its exposure to foreign currency exchange rate risk through the use of foreign currency swaps converting all interest and principal payments to fixed-rate U.S. dollars.

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, 2017 when compared to the year ended December 31, 2016.

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:

	2017 Changes	2016 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ 41**	$ (213)
Acquisitions	**—**	(54)
Contracts realized or settled	**(8)**	141
Current period changes[(a)]	**(196)**	171
Contracts outstanding at the end of the period, assets (liabilities), net[(b)]	**$ (163)**	$ 45

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

(b) Excludes premium and intrinsic value associated with weather derivatives of $11 million at December 31, 2017 and includes premium and intrinsic value associated with weather derivatives of $4 million at December 31, 2016.

The net hedge volumes of energy-related derivative contracts were 621 million mmBtu and 500 million mmBtu for the years ended December 31, 2017 and 2016, respectively.

For the traditional electric operating companies and Southern Power, the weighted average swap contract cost above or (below) market prices was approximately $0.15 per mmBtu as of December 31, 2017 and $(0.05) per mmBtu as of December 31, 2016. 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, 2017 and 2016, 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, 2017 were as follows:

	Fair Value Measurements December 31, 2017			
		Maturity		
(in millions)	Total Fair Value	Year 1	Years 2&3	Years 4&5
Level 1	$(148)	$ (71)	$(59)	$(18)
Level 2	(15)	(30)	13	2
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$(163)	$(101)	$(46)	$(16)

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.

With the exception of Southern Company Gas' subsidiary, Atlanta Gas Light, and the Southern Company Gas wholesale gas services business, the Southern Company system is not exposed to concentrations of credit risk. Concentration of credit risk occurs at Atlanta Gas Light for amounts billed for services and other costs to its customers, which consist of 15 natural gas marketers in Georgia responsible for the retail sale of natural gas to end-use customers in Georgia. For 2017, the four largest natural gas marketers based on customer count accounted for 19% of Southern Company Gas' adjusted operating margin. Southern Company Gas' wholesale gas services business has a concentration of credit risk for services it provides to its counterparties as measured by its 30-day receivable exposure plus forward exposure. At December 31, 2017, Southern Company Gas' wholesale gas services business' top 20 counterparties represented approximately 48%, or $203 million, of its total counterparty exposure and had a weighted average S&P equivalent credit rating of A-, all of which is consistent with the prior year.

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 $9.4 billion for 2018, $9.3 billion for 2019, $8.4 billion for 2020, $7.0 billion for 2021, and $6.9 billion for 2022. These amounts include expenditures of approximately $1.2 billion, $1.0 billion, $0.9 billion, $0.7 billion, and $0.4 billion for the construction of Plant Vogtle Units 3 and 4 in 2018, 2019, 2020, 2021, and 2022, respectively, and an average of approximately $1.3 billion per year for 2018 through 2022 for Southern Power's planned expenditures for plant acquisitions and placeholder growth. These amounts also include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under LTSAs. Estimated capital expenditures to comply with environmental laws and regulations included in these amounts are $1.1 billion, $0.3 billion, $0.4 billion, $0.5 billion, and $0.5 billion for 2018, 2019, 2020, 2021, and 2022, respectively. These estimated expenditures do not include any potential compliance costs associated with the regulation of CO_2 emissions from fossil fuel-fired electric generating units. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws 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 $0.3 billion, $0.3 billion, $0.4 billion, $0.5 billion, and $0.4 billion for 2018, 2019, 2020, 2021, and 2022, 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 laws 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 previously constructed, which may result in revised estimates during construction. The ability to control costs and avoid cost overruns during the development, construction, and operation 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, 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. See Note 3 to the financial statements under "Nuclear Construction" 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, the Southern Company system 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 stock dividends, leases, unrecognized tax benefits, pipeline charges, storage capacity, gas supply, asset management agreements, 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.

Contractual Obligations

The Southern Company system's contractual obligations at December 31, 2017 were as follows:

(in millions)	2018	2019–2020	2021–2022	After 2022	Total
Long-term debt[a] —					
Principal	$ 3,865	$ 6,293	$ 5,206	$32,610	$ 47,974
Interest	1,782	3,286	2,793	27,535	35,396
Preferred stock dividends of subsidiaries[b]	16	33	33	—	82
Financial derivative obligations[c]	493	198	37	5	733
Operating leases[d]	149	232	178	968	1,527
Capital leases[d]	39	43	20	232	334
Unrecognized tax benefits[e]	18	—	—	—	18
Pipeline charges, storage capacity, and gas supply[f]	813	968	714	2,294	4,789
Asset management agreements[g]	9	6	—	—	15
Purchase commitments —					
Capital[h]	9,016	16,905	12,749	—	38,670
Fuel[i]	3,156	3,573	1,927	5,588	14,244
Purchased power[j]	424	884	886	3,716	5,910
Other[k]	407	713	434	2,745	4,299
Trusts —					
Nuclear decommissioning[l]	5	11	11	94	121
Pension and other postretirement benefit plans[m]	137	275	—	—	412
Total	$20,329	$33,420	$24,988	$75,787	$154,524

(a) All amounts are reflected based on final maturity dates except for amounts related to FFB borrowings and certain revenue bonds. 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" and "Securities Due Within One Year" 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 December 31, 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) Represents preferred stock of subsidiaries. Preferred stock does not mature; therefore, amounts are provided for the next five years only.

(c) 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 35 million mmBtu at floating gas prices calculated using forward natural gas prices at December 31, 2017 and valued at $101 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) 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 LTSAs which are reflected in "Fuel" and "Other," respectively. At December 31, 2017, significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations" herein for additional information.

(i) 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, 2017.

(j) Estimated minimum long-term obligations for various PPA purchases from gas-fired, biomass, and wind-powered facilities.

(k) Includes LTSAs, contracts for the procurement of limestone, contractual environmental remediation liabilities, and operation and maintenance agreements. LTSAs include price escalation based on inflation indices.

(l) 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.

(m) 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.

Consolidated Statements of Income

For the Years Ended December 31, 2017, 2016, and 2015

(in millions)	**2017**	2016	2015
Operating Revenues:			
Retail electric revenues	**$15,330**	$15,234	$14,987
Wholesale electric revenues	**2,426**	1,926	1,798
Other electric revenues	**681**	698	657
Natural gas revenues	**3,791**	1,596	—
Other revenues	**803**	442	47
Total operating revenues	**23,031**	19,896	17,489
Operating Expenses:			
Fuel	**4,400**	4,361	4,750
Purchased power	**863**	750	645
Cost of natural gas	**1,601**	613	—
Cost of other sales	**513**	260	—
Other operations and maintenance	**5,481**	5,240	4,416
Depreciation and amortization	**3,010**	2,502	2,034
Taxes other than income taxes	**1,250**	1,113	997
Estimated loss on Kemper IGCC	**3,362**	428	365
Total operating expenses	**20,480**	15,267	13,207
Operating Income	**2,551**	4,629	4,282
Other Income and (Expense):			
Allowance for equity funds used during construction	**160**	202	226
Earnings from equity method investments	**106**	59	—
Interest expense, net of amounts capitalized	**(1,694)**	(1,317)	(840)
Other income (expense), net	**(55)**	(93)	(39)
Total other income and (expense)	**(1,483)**	(1,149)	(653)
Earnings Before Income Taxes	**1,068**	3,480	3,629
Income taxes	**142**	951	1,194
Consolidated Net Income	**926**	2,529	2,435
Less:			
Dividends on preferred and preference stock of subsidiaries	**38**	45	54
Net income attributable to noncontrolling interests	**46**	36	14
Consolidated Net Income Attributable to Southern Company	**$ 842**	$ 2,448	$ 2,367
Common Stock Data:			
Earnings per share —			
Basic	**$ 0.84**	$ 2.57	$ 2.60
Diluted	**0.84**	2.55	2.59
Average number of shares of common stock outstanding — (*in millions*)			
Basic	**1,000**	951	910
Diluted	**1,008**	958	914

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

Consolidated Statements of Comprehensive Income

For the Years Ended December 31, 2017, 2016, and 2015

(in millions)	**2017**	2016	2015
Consolidated Net Income	**$926**	$2,529	$2,435
Other comprehensive income:			
Qualifying hedges:			
Changes in fair value, net of tax of $34, $(84), and $(8), respectively	**57**	(136)	(13)
Reclassification adjustment for amounts included in net income, net of tax of $(37), $43, and $4, respectively	**(60)**	69	6
Pension and other postretirement benefit plans:			
Benefit plan net gain (loss), net of tax of $6, $10, and $(1), respectively	**17**	13	(2)
Reclassification adjustment for amounts included in net income, net of tax of $(6), $3, and $4, respectively	**(23)**	4	7
Total other comprehensive income (loss)	**(9)**	(50)	(2)
Less:			
Dividends on preferred and preference stock of subsidiaries	**38**	45	54
Comprehensive income attributable to noncontrolling interests	**46**	36	14
Consolidated Comprehensive Income Attributable to Southern Company	**$833**	$2,398	$2,365

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

Consolidated Statements of Cash Flows

For the Years Ended December 31, 2017, 2016, and 2015

(in millions)	**2017**	2016	2015
Operating Activities:			
Consolidated net income	**$ 926**	$ 2,529	$ 2,435
Adjustments to reconcile consolidated net income to net cash provided from operating activities —			
Depreciation and amortization, total	**3,457**	2,923	2,395
Deferred income taxes	**166**	(127)	1,404
Collateral deposits	**(4)**	(102)	—
Allowance for equity funds used during construction	**(160)**	(202)	(226)
Pension and postretirement funding	**(2)**	(1,029)	(7)
Settlement of asset retirement obligations	**(177)**	(171)	(37)
Stock based compensation expense	**109**	121	99
Hedge settlements	**6**	(233)	(17)
Estimated loss on Kemper IGCC	**3,179**	428	365
Income taxes receivable, non-current	**(47)**	(122)	(413)
Other, net	**(109)**	(99)	49
Changes in certain current assets and liabilities —			
-Receivables	**(199)**	(544)	243
-Fossil fuel for generation	**36**	178	61
-Natural gas for sale	**36**	(226)	—
-Other current assets	**(143)**	(206)	(152)
-Accounts payable	**(280)**	301	(353)
-Accrued taxes	**(142)**	1,456	352
-Retail fuel cost over recovery	**(212)**	(231)	289
-Mirror CWIP	**—**	—	(271)
-Other current liabilities	**(45)**	250	58
Net cash provided from operating activities	**6,395**	4,894	6,274
Investing Activities:			
Business acquisitions, net of cash acquired	**(1,070)**	(10,689)	(1,719)
Property additions	**(7,423)**	(7,310)	(5,674)
Proceeds pursuant to the Toshiba Guarantee, net of joint owner portion	**1,682**	—	—
Investment in restricted cash	**(17)**	(733)	(160)
Distribution of restricted cash	**34**	742	154
Nuclear decommissioning trust fund purchases	**(811)**	(1,160)	(1,424)
Nuclear decommissioning trust fund sales	**805**	1,154	1,418
Cost of removal, net of salvage	**(313)**	(245)	(167)
Change in construction payables, net	**259**	(121)	402
Investment in unconsolidated subsidiaries	**(152)**	(1,444)	—
Payments pursuant to LTSAs	**(227)**	(134)	(197)
Other investing activities	**42**	(108)	87
Net cash used for investing activities	**(7,191)**	(20,048)	(7,280)

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

(in millions)	**2017**	2016	2015
Financing Activities:			
Increase (decrease) in notes payable, net	**(401)**	1,228	73
Proceeds —			
Long-term debt	**5,858**	16,368	7,029
Common stock	**793**	3,758	256
Preferred stock	**250**	—	—
Short-term borrowings	**1,259**	—	755
Redemptions and repurchases —			
Long-term debt	**(2,930)**	(3,145)	(3,604)
Common stock	**—**	—	(115)
Interest-bearing refundable deposits	**—**	—	(275)
Preferred and preference stock	**(658)**	—	(412)
Short-term borrowings	**(659)**	(478)	(255)
Distributions to noncontrolling interests	**(119)**	(72)	(18)
Capital contributions from noncontrolling interests	**80**	682	341
Payment of common stock dividends	**(2,300)**	(2,104)	(1,959)
Other financing activities	**(222)**	(512)	(116)
Net cash provided from financing activities	**951**	15,725	1,700
Net Change in Cash and Cash Equivalents	**155**	571	694
Cash and Cash Equivalents at Beginning of Year	**1,975**	1,404	710
Cash and Cash Equivalents at End of Year	**$ 2,130**	$ 1,975	$ 1,404

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

Consolidated Balance Sheets

At December 31, 2017 and 2016

Assets *(in millions)*	**2017**	2016
Current Assets:		
Cash and cash equivalents	**$ 2,130**	$ 1,975
Receivables —		
Customer accounts receivable	**1,806**	1,583
Energy marketing receivable	**607**	623
Unbilled revenues	**810**	706
Under recovered fuel clause revenues	**171**	—
Income taxes receivable, current	**63**	544
Other accounts and notes receivable	**635**	377
Accumulated provision for uncollectible accounts	**(44)**	(43)
Materials and supplies	**1,438**	1,462
Fossil fuel for generation	**594**	689
Natural gas for sale	**595**	631
Prepaid expenses	**452**	364
Other regulatory assets, current	**604**	581
Other current assets	**211**	230
Total current assets	**10,072**	9,722
Property, Plant, and Equipment:		
In service	**103,542**	98,416
Less: Accumulated depreciation	**31,457**	29,852
Plant in service, net of depreciation	**72,085**	68,564
Nuclear fuel, at amortized cost	**883**	905
Construction work in progress	**6,904**	8,977
Total property, plant, and equipment	**79,872**	78,446
Other Property and Investments:		
Goodwill	**6,268**	6,251
Equity investments in unconsolidated subsidiaries	**1,513**	1,549
Other intangible assets, net of amortization of $186 and $62 at December 31, 2017 and December 31, 2016, respectively	**873**	970
Nuclear decommissioning trusts, at fair value	**1,832**	1,606
Leveraged leases	**775**	774
Miscellaneous property and investments	**249**	270
Total other property and investments	**11,510**	11,420
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**825**	1,629
Unamortized loss on reacquired debt	**206**	223
Other regulatory assets, deferred	**6,943**	6,851
Other deferred charges and assets	**1,577**	1,406
Total deferred charges and other assets	**9,551**	10,109
Total Assets	**$111,005**	$109,697

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

Liabilities and Stockholders' Equity *(in millions)*	**2017**	2016
Current Liabilities:		
Securities due within one year	**$ 3,892**	$ 2,587
Notes payable	**2,439**	2,241
Energy marketing trade payables	**546**	597
Accounts payable	**2,530**	2,228
Customer deposits	**542**	558
Accrued taxes —		
Accrued income taxes	**6**	193
Unrecognized tax benefits	**18**	385
Other accrued taxes	**613**	667
Accrued interest	**488**	518
Accrued compensation	**959**	915
Asset retirement obligations, current	**351**	378
Acquisitions payable	**5**	489
Other regulatory liabilities, current	**337**	236
Other current liabilities	**868**	925
Total current liabilities	**13,594**	12,917
Long-Term Debt (See accompanying statements)	**44,462**	42,629
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**6,842**	14,092
Deferred credits related to income taxes	**7,256**	219
Accumulated deferred ITCs	**2,267**	2,228
Employee benefit obligations	**2,256**	2,299
Asset retirement obligations, deferred	**4,473**	4,136
Accrued environmental remediation	**389**	397
Other cost of removal obligations	**2,684**	2,748
Other regulatory liabilities, deferred	**239**	258
Other deferred credits and liabilities	**691**	880
Total deferred credits and other liabilities	**27,097**	27,257
Total Liabilities	**85,153**	82,803
Redeemable Preferred Stock of Subsidiaries (See accompanying statements)	**324**	118
Redeemable Noncontrolling Interests (See accompanying statements)	**—**	164
Total Stockholders' Equity (See accompanying statements)	**25,528**	26,612
Total Liabilities and Stockholders' Equity	**$111,005**	$109,697
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, 2017 and 2016

		2017	2016	2017	2016
		(in millions)		*(percent of total)*	
Long-Term Debt:					
Long-term debt payable to affiliated trusts —					
Variable rate (4.44% at 12/31/17) due 2042		**$ 206**	$ 206		
Long-term senior notes and debt —					
Maturity	Interest Rates				
2017	1.30% to 7.20%	**—**	2,019		
2018	1.50% to 5.40%	**2,402**	2,403		
2019	1.85% to 5.55%	**3,074**	3,076		
2020	2.00% to 4.75%	**2,273**	1,326		
2021	2.35% to 9.10%	**2,643**	2,655		
2022	1.00% to 8.70%	**2,016**	1,378		
2023 through 2047	1.85% to 7.30%	**22,142**	20,369		
Variable rates (1.82% to 3.75% at 1/1/17) due 2017		**—**	461		
Variable rates (2.29% to 3.05% at 12/31/17) due 2018		**1,420**	1,520		
Variable rates (2.04% to 2.18% at 12/31/17) due 2020		**825**	—		
Variable rates (2.55% to 2.79% at 12/31/17) due 2021		**25**	25		
Variable rate (3.75% at 1/1/17) due 2032 to 2036		**—**	15		
Total long-term senior notes and debt		**36,820**	35,247		
Other long-term debt —					
Pollution control revenue bonds —					
Maturity	Interest Rates				
2019	4.55%	**25**	25		
2022	2.10% to 2.35%	**90**	90		
2023 through 2049	1.15% to 5.15%	**1,379**	1,339		
Variable rates (2.45% to 2.50% at 12/31/17) due 2018		**40**	76		
Variable rates (1.86% to 1.87% at 12/31/17) due 2021		**65**	65		
Variable rates (1.83% to 1.84% at 12/31/17) due 2022		**17**	17		
Variable rates (1.59% to 1.88% at 12/31/17) due 2024 to 2053		**1,680**	1,721		
Plant Daniel revenue bonds (7.13%) due 2021		**270**	270		
FFB loans —					
2.57% to 3.86% due 2020		**44**	44		
2.57% to 3.86% due 2021		**44**	44		
2.57% to 3.86% due 2022		**44**	44		
2.57% to 3.86% due 2023 to 2044		**2,493**	2,493		
First mortgage bonds —					
4.70% due 2019		**50**	50		
2.66% to 6.58% due 2023 to 2057		**975**	575		
Gas facility revenue bonds —					
Variable rate (1.71% at 12/31/17) due 2022		**47**	47		
Variable rate (1.71% at 12/31/17) due 2024 to 2033		**154**	154		
Junior subordinated notes (5.00% to 6.25%) due 2057 to 2077		**3,570**	2,350		
Total other long-term debt		**10,987**	9,404		
Unamortized fair value adjustment of long-term debt		**525**	578		
Capitalized lease obligations		**204**	136		
Unamortized debt premium		**44**	52		
Unamortized debt discount		**(206)**	(194)		
Unamortized debt issuance expense		**(226)**	(213)		
Total long-term debt (annual interest requirement — $1.8 billion)		**48,354**	45,216		
Less amount due within one year		**3,892**	2,587		
Long-term debt excluding amount due within one year		**44,462**	42,629	**63.2%**	61.3%

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

	2017	2016	2017	2016
	(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	**324**	81		
$1 par value — 5.83%				
Authorized — 28 million shares				
Outstanding — 2017: no shares — 2016: 2 million shares: $25 stated value	**—**	37		
Total redeemable preferred stock of subsidiaries (annual dividend requirement — $16 million)	**324**	118	**0.5**	0.2
Redeemable Noncontrolling Interests	**—**	164	**—**	0.2
Common Stockholders' Equity:				
Common stock, par value $5 per share —	**5,038**	4,952		
Authorized — 1.5 billion shares				
Issued — 2017: 1.0 billion shares — 2016: 991 million shares				
Treasury — 2017: 0.9 million shares — 2016: 0.8 million shares				
Paid-in capital	**10,469**	9,661		
Treasury, at cost	**(36)**	(31)		
Retained earnings	**8,885**	10,356		
Accumulated other comprehensive loss	**(189)**	(180)		
Total common stockholders' equity	**24,167**	24,758	**34.4**	35.6
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 — 2017: no shares — 2016: 2 million shares	**—**	45		
Non-cumulative preference stock				
$1 par value — 6.45% to 6.50%				
Authorized — 65 million shares				
Outstanding — 2017: no shares — 2016: 8 million shares	**—**	196		
$100 par or stated value — 5.60% to 6.50%				
Outstanding — 2017: no shares — 2016: 4 million shares	**—**	368		
Noncontrolling interests	**1,361**	1,245		
Total preferred and preference stock of subsidiaries and noncontrolling interests	**1,361**	1,854	**1.9**	2.7
Total stockholders' equity	**25,528**	26,612		
Total Capitalization	**$70,314**	$69,523	**100.0%**	100.0%

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

Consolidated Statements of Stockholders' Equity

For the Years Ended December 31, 2017, 2016, and 2015

	Southern Company Common Stockholders' Equity									
	Number of Common Shares		Common Stock							
	Issued	Treasury	Par Value	Paid-In Capital	Treasury	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Preferred and Preference Stock of Subsidiaries	Noncontrolling Interests	Total
	(in thousands)		*(in millions)*							
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 redemption	—	—	—	—	—	—	—	(150)	—	(150)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	—	567	567
Distributions to noncontrolling interests	—	—	—	—	—	—	—	—	(18)	(18)
Net loss 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 noncontrolling interests	—	—	—	—	—	—	—	—	32	32
Other	—	(66)	—	(4)	(4)	2	—	—	—	(6)

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

	Southern Company Common Stockholders' Equity									
	Number of Common Shares		Common Stock							
	Issued	Treasury	Par Value	Paid-In Capital	Treasury	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Preferred and Preference Stock of Subsidiaries	Noncontrolling Interests	Total
	(in thousands)		*(in millions)*							
Balance at December 31, 2016	**991,213**	**(819)**	**4,952**	**9,661**	**(31)**	**10,356**	**(180)**	**609**	**1,245**	**26,612**
Consolidated net income attributable to Southern Company	—	—	—	—	—	**842**	—	—	—	**842**
Other comprehensive income (loss)	—	—	—	—	—	—	**(9)**	—	—	**(9)**
Stock issued	**17,319**	—	**86**	**707**	—	—	—	—	—	**793**
Stock-based compensation	—	—	—	**105**	—	—	—	—	—	**105**
Cash dividends of $2.3000 per share	—	—	—	—	—	**(2,300)**	—	—	—	**(2,300)**
Preferred and preference stock redemptions	—	—	—	—	—	—	—	**(609)**	—	**(609)**
Contributions from noncontrolling interests	—	—	—	—	—	—	—	—	**79**	**79**
Distributions to noncontrolling interests	—	—	—	—	—	—	—	—	**(122)**	**(122)**
Net income attributable to noncontrolling interests	—	—	—	—	—	—	—	—	**44**	**44**
Reclassification from redeemable noncontrolling interests	—	—	—	—	—	—	—	—	**114**	**114**
Other	—	**(110)**	—	**(4)**	**(5)**	**(13)**	—	—	**1**	**(21)**
Balance at December 31, 2017	**1,008,532**	**(929)**	**$ 5,038**	**$ 10,469**	**$ (36)**	**$ 8,885**	**$ (189)**	**$ —**	**$ 1,361**	**$ 25,528**

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

Index to the Notes to Financial Statements

NOTE 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 develops, 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. 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 optics 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 managing construction of Plant Vogtle Units 3 and 4. PowerSecure is a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure. See Note 12 under "Southern Company Gas – Proposed Sale of Elizabethtown Gas and Elkton Gas" for information regarding agreements entered into by a wholly-owned subsidiary of Southern Company Gas to sell two of its natural gas distribution utilities.

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 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

Revenue

In 2014, the FASB issued ASC 606, *Revenue from Contracts with Customers* (ASC 606), 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 new standard 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.

Most of Southern Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity or natural gas without a defined contractual term, as well as longer-term contractual commitments, including PPAs and non-derivative natural gas asset management and optimization arrangements.

Southern Company has completed the evaluation of all revenue streams and determined that the adoption of ASC 606 will not change the current timing of revenue recognition for such transactions. Some revenue arrangements, such as certain PPAs, energy-related derivatives, and alternative revenue programs, are excluded from the scope of ASC 606 and, therefore, will be accounted for and disclosed or presented separately from revenues under ASC 606 on Southern Company's financial statements. Southern Company has concluded contributions in aid of construction are not in scope for ASC 606 and will continue to be accounted for as an offset to property, plant, and equipment.

The new standard is effective for reporting periods beginning after December 15, 2017. Southern Company applied the modified retrospective method of adoption effective January 1, 2018. Southern Company also utilized practical expedients which allowed it to apply the standard to open contracts at the date of adoption and to reflect the aggregate effect of all modifications when identifying performance obligations and allocating the transaction price for contracts modified before the effective date. Under the modified retrospective method of adoption, prior year reported results are not restated; however, a cumulative-effect adjustment to retained earnings at January 1, 2018 is recorded. In addition, quarterly disclosures will include comparative information on 2018 financial statement line items under current guidance. The adoption of ASC 606 did not result in a cumulative-effect adjustment.

Leases

In February 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 and Southern Company will adopt the new standard effective January 1, 2019.

Southern Company is currently implementing an information technology system along with the related changes to internal controls and accounting policies that will support the accounting for leases under ASU 2016–02. In addition, Southern Company has substantially completed a detailed inventory and analysis of its leases. In terms of rental charges and duration of contracts, the most significant leases relate to cellular towers and PPAs where certain of Southern Company's subsidiaries are the lessee and to land and outdoor lighting where certain of Southern Company's subsidiaries are the lessor. The traditional electric operating companies are currently analyzing pole attachment agreements, and a lease determination has not been made at this time. While Southern Company has not yet determined the ultimate impact, adoption of ASU 2016–02 is expected to have a significant impact on Southern Company's balance sheet.

Other

In March 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 and 8 for disclosures impacted by ASU 2016–09.

In November 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, and will be applied retrospectively to each period presented. Southern Company adopted ASU 2016–18 effective January 1, 2018 with no material impact on its financial statements.

On January 26, 2017, the FASB issued ASU No. 2017–04, *Intangibles – Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment* (ASU 2017–04). ASU 2017–04 removes the requirement to compare the implied fair value of goodwill with the carrying amount as part of Step 2 of the goodwill impairment test. Under the new standard, the goodwill impairment loss will be measured as the excess of a reporting unit's carrying amount over its fair value, not exceeding the total amount of goodwill allocated to that reporting unit, which may increase the frequency of goodwill impairment charges if a future goodwill impairment test does not pass the Step 1 evaluation. ASU 2017–04 is effective prospectively for periods beginning on or after December 15, 2019, with early adoption permitted. Southern Company adopted ASU 2017–04 effective January 1, 2018 with no impact on its financial statements.

On March 10, 2017, the FASB issued ASU No. 2017–07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (ASU 2017–07). ASU 2017–07 requires that an employer report the service cost component in the same line item or items as other compensation costs and requires the other components of net periodic pension and postretirement benefit costs to be separately presented in the income statement outside of income from operations. Additionally, only the service cost component is eligible for capitalization, when applicable. However, all cost components remain eligible for capitalization under FERC regulations. ASU 2017–07 will be applied retrospectively for the presentation of the service cost component and the other components of net periodic pension and postretirement benefit costs in the income statement. The capitalization of only the service cost component of net periodic pension and postretirement benefit costs in assets will be applied on a prospective basis. ASU 2017–07 is effective for periods beginning after December 15, 2017. The presentation changes required for net periodic pension and postretirement benefit costs will result in a decrease in Southern Company's operating income and an increase in other income for 2016 and 2017 and are expected to result in a decrease in operating income and an increase in other income for 2018. Southern Company adopted ASU 2017–07 effective January 1, 2018 with no material impact on its financial statements.

On August 28, 2017, the FASB issued ASU No. 2017–12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities* (ASU 2017–12), amending the hedge accounting recognition and presentation requirements. ASU 2017–12 makes more financial and non-financial hedging strategies eligible for hedge accounting, amends the related presentation and disclosure requirements, and simplifies hedge effectiveness assessment requirements. ASU 2017–12 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. Southern Company adopted ASU 2017–12 effective January 1, 2018 with no material impact on its financial statements.

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.

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

(in millions)	**2017**	2016	Note
Retiree benefit plans	**$ 3,931**	$ 3,959	(a,n)
Asset retirement obligations-asset	**1,133**	1,080	(b,n)
Deferred income tax charges	**814**	1,590	(b,p)
Environmental remediation-asset	**511**	491	(j,n)
Property damage reserves-asset	**333**	206	(i)
Under recovered regulatory clause revenues	**317**	273	(g)
Remaining net book value of retired assets	**306**	351	(o)
Loss on reacquired debt	**223**	243	(c)
Vacation pay	**183**	182	(f,n)
Long-term debt fair value adjustment	**138**	155	(d)
Deferred PPA charges	**119**	141	(e,n)
Kemper County energy facility	**88**	201	(h)
Other regulatory assets	**511**	487	(k)
Deferred income tax credits	**(7,261)**	(219)	(b,p)
Other cost of removal obligations	**(2,684)**	(2,774)	(b)
Over recovered regulatory clause revenues	**(155)**	(203)	(g)
Property damage reserves-liability	**(135)**	(177)	(l)
Other regulatory liabilities	**(266)**	(120)	(m)
Total regulatory assets (liabilities), net	**$(1,894)**	$ 5,866	

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 80 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) Recovered over the remaining life of the original debt issuances, which range up to 21 years. For additional information see Note 12 under "Southern Company – Merger with Southern Company Gas."
(e) Recovered over the life of the PPA for periods up to six 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 10 years.
(h) Includes $114 million of regulatory assets and $26 million of regulatory liabilities to be recovered over periods of eight and six years, respectively. For additional information, see Note 3 under "Kemper County Energy Facility – Rate Recovery – Kemper Settlement Agreement."
(i) Previous under-recovery as of December 2013 is recorded and recovered or amortized as approved by the Georgia PSC through 2019. Amortization of $319 million related to the under-recovery from January 2014 through December 2017 is expected to be determined by the Georgia PSC in the 2019 base rate case. See Note 3 under "Regulatory Matters – Georgia Power – Storm Damage Recovery" 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 nuclear outage, fuel-hedging losses, 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, AROs, 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 20 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 48 years.
(p) As a result of the Tax Reform Legislation, these accounts include certain deferred income tax assets and liabilities not subject to normalization. The recovery and amortization of these amounts will be determined by the appropriate state PSCs or other applicable regulatory agencies. See Note 3 under "Regulatory Matters" and Note 5 for additional information.

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," " – Georgia Power," " – Gulf Power," and " – Southern Company Gas" and "Kemper County Energy Facility" 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. For the traditional electric operating companies, 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 tariffs for several of the natural gas distribution utilities include provisions which allow for the recognition of certain revenues prior to the time such revenues are billed to customers, so long as the amounts recognized will be collected from customers within 24 months. Programs of this type include weather normalization adjustments, revenue normalization mechanisms, and revenue true-up adjustments and are referred to as alternative revenue programs.

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.

Cost of Natural Gas

Excluding Atlanta Gas Light, which does not sell natural gas to end-use customers, Southern Company Gas charges its utility customers for natural gas consumed using natural gas cost recovery mechanisms set by the applicable state regulatory agencies. Under these mechanisms, all prudently-incurred natural gas costs are passed through to customers without markup, subject to regulatory review.

Southern Company Gas defers or accrues the difference between the actual cost of natural gas and the amount of commodity revenue earned in a given period such that no operating income is recognized related to these costs. The deferred or accrued amount is either billed or refunded to customers prospectively through adjustments to the commodity rate. Deferred and accrued natural gas costs are included in the balance sheets as regulatory assets and regulatory liabilities, respectively.

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 2017 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 2017 tax year along with various state NOL carryforwards, which would 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.

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

(in millions)	**2017**	2016
Electric utilities:		
Generation	**$ 51,279**	$48,836
Transmission	**11,562**	11,156
Distribution	**19,239**	18,418
General	**4,276**	4,629
Plant acquisition adjustment	**126**	126
Electric utility plant in service	**86,482**	83,165
Natural gas distribution utilities:		
Transportation and distribution	**13,078**	11,996
Utility plant in service	**99,560**	95,161
Information technology equipment and software	**752**	544
Communications equipment	**456**	424
Storage facilities	**1,598**	1,463
Other	**1,176**	824
Total other plant in service	**3,982**	3,255
Total plant in service	**$103,542**	$98,416

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. In accordance with their respective state PSC orders, Alabama Power and Georgia Power defer and amortize nuclear refueling costs over the unit's operating cycle, which ranges from 18 to 24 months.

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,	
(in millions)	**2017**	2016
Office buildings	**$216**	$ 61
Nitrogen plant[(*)]	**—**	83
Computer-related equipment	**51**	63
Gas pipeline	**6**	6
Less: Accumulated amortization	**(72)**	(69)
Balance, net of amortization	**$201**	$144

(*) Represents a nitrogen supply agreement for the air separation unit of the Kemper County energy facility, which was terminated following the suspension of the gasifier portion of the project. See Note 6 under "Capital Leases" for additional information.

The amount of non-cash property additions recognized for the years ended December 31, 2017, 2016, and 2015 was $985 million, $1.3 billion, and $844 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, 2017, 2016, and 2015 was $162 million, $18 million, and $13 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 2.9% in 2017 and 3.0% in each of 2016 and 2015. Depreciation studies are conducted periodically to update the composite rates. These studies are filed with the respective state PSC and/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 $30.8 billion and $29.3 billion at December 31, 2017 and 2016, 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 related to natural gas-fired facilities 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.

Under the terms of the 2013 ARP, Georgia Power amortized approximately $14 million annually from 2014 through 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 two to 65 years. Accumulated depreciation for other plant in service totaled $673 million and $550 million at December 31, 2017 and 2016, 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 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:

(in millions)	**2017**	2016
Balance at beginning of year	**$4,514**	$3,759
Liabilities incurred	**16**	66
Liabilities settled	**(177)**	(171)
Accretion	**179**	162
Cash flow revisions	**292**	698
Balance at end of year	**$4,824**	$4,514

In 2017 and 2016, the increases in cash flow revisions are primarily related to changes in closure strategy for ash ponds, landfills, and gypsum cells and the increases in liabilities settled are primarily related to ash pond closure activity.

The cost estimates for AROs related to the CCR Rule are based on information as of December 31, 2017 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 and closure details are developed, the traditional electric operating companies will continue to periodically update these cost estimates as necessary.

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, 2017 and 2016, approximately $76 million and $56 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 $77 million and $58 million at December 31, 2017 and 2016, 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, 2017, investment securities in the Funds totaled $1.8 billion, consisting of equity securities of $1.1 billion, debt securities of $725 million, and $47 million of other securities. 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. 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 securities lending program.

Sales of the securities held in the Funds resulted in cash proceeds of $0.8 billion, $1.2 billion, and $1.4 billion in 2017, 2016, and 2015, respectively, all of which were reinvested. For 2017, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $233 million, which included $181 million related to unrealized gains on securities held in the Funds at December 31, 2017. 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 losses 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 gains and losses on securities held in the Funds at December 31, 2015. 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.

For Alabama Power, approximately $18 million and $19 million at December 31, 2017 and 2016, 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, 2017 and 2016, the accumulated provisions for the external decommissioning trust funds were as follows:

	External Trust Funds	
(in millions)	**2017**	2016
Plant Farley	**$902**	$790
Plant Hatch	**583**	511
Plant Vogtle Units 1 and 2	**346**	303

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, 2017 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, as a percentage of net income, was 25.5%, 11.4%, and 12.8% for 2017, 2016, and 2015, respectively.

Cash payments for interest totaled $1.7 billion, $1.1 billion, and $809 million in 2017, 2016, and 2015, respectively, net of amounts capitalized of $89 million, $125 million, and $124 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 "Leveraged Leases" herein and Note 3 under "Other Matters" and "Kemper County Energy Facility – Schedule and Cost Estimate" for additional information.

Goodwill and Other Intangible Assets and Liabilities

Southern Company's goodwill and other intangible assets and liabilities primarily relate to Southern Company's 2016 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. Also see Note 12 under "Southern Power" for additional information regarding other intangible assets related to Southern Power's PPA fair value adjustments.

At December 31, 2017 and 2016, goodwill was $6.3 billion. 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 2017 and determined that no impairment was required.

At December 31, 2017 and 2016, other intangible assets were as follows:

		At December 31, 2017			At December 31, 2016		
	Estimated Useful Life	Gross Carrying Amount	Accumulated Amortization	Other Intangible Assets, Net	Gross Carrying Amount	Accumulated Amortization	Other Intangible Assets, Net
			(in millions)			*(in millions)*	
Other intangible assets subject to amortization:							
Customer relationships	11–26 years	$ 288	$ (83)	$205	$ 268	$(32)	$236
Trade names	5–28 years	159	(17)	142	158	(5)	153
Storage and transportation contracts	1–5 years	64	(34)	30	64	(2)	62
PPA fair value adjustments	10–20 years	456	(47)	409	456	(22)	434
Other	1–12 years	17	(5)	12	11	(1)	10
Total other intangible assets subject to amortization		$ 984	$(186)	$798	$ 957	$(62)	$895
Other intangible assets not subject to amortization:							
Federal Communications Commission licenses		75	—	75	75	—	75
Total other intangible assets		$1,059	$(186)	$873	$1,032	$(62)	$970

Amortization associated with other intangible assets in 2017, 2016, and 2015 totaled $124 million, $50 million, and $3 million, respectively.

As of December 31, 2017, the estimated amortization associated with other intangible assets for the next five years is as follows:

(in millions)	Amortization
2018	$95
2019	77
2020	65
2021	56
2022	51

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, 2017, the accumulated amortization of these intangible liabilities was $50 million. The remaining estimated amortization associated with the intangible liabilities that will be recorded in natural gas revenues is as follows:

(in millions)	Amortization
2018	$24
2019	17

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 $41 million in 2017 and $40 million in each of 2016 and 2015. 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 2017, 2016, and 2015, 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

A subsidiary of Southern Holdings 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.

The ability of the lessees to make required payments to the Southern Holdings subsidiary is dependent on the operational performance of the assets. In the last six months of 2017, the financial and operational performance of one of the lessees and the associated generation assets has raised significant concerns about the short-term ability of the generation assets to produce cash flows sufficient to support ongoing operations and the lessee's contractual obligations and its ability to make the remaining semi-annual lease payments to the Southern Holdings subsidiary beginning in June 2018. These operational challenges may also impact the expected residual value of the assets at the end of the lease term in 2047. If the June 2018 (or any future) lease payment is not paid in full, the Southern Holdings subsidiary may be unable to make its corresponding payment to the holders of the underlying non-recourse debt related to the generation assets. Failure to make the required payment to the debtholders would represent an event of default that would give the debtholders the right to foreclose on, and take ownership of, the generation assets from the Southern Holdings subsidiary, in effect terminating the lease and resulting in the write-off of the related lease receivable which had a balance of approximately $86 million as of December 31, 2017. Southern Company has evaluated the recoverability of the lease receivable and the expected residual value of the generation assets at the end of the lease under various scenarios and has concluded that its investment in the leveraged lease is not impaired as of December 31, 2017. Southern Company will continue to monitor the operational performance of the underlying assets and evaluate the ability of the lessee to continue to make the required lease payments, including the lease payment due in June 2018. The ultimate outcome of this matter cannot be determined at this time.

Southern Company's net investment in domestic and international leveraged leases consists of the following at December 31:

(in millions)	**2017**	2016
Net rentals receivable	**$1,498**	$1,481
Unearned income	**(723)**	(707)
Investment in leveraged leases	**775**	774
Deferred taxes from leveraged leases	**(252)**	(309)
Net investment in leveraged leases	**$ 523**	$ 465

A summary of the components of income from the leveraged leases follows:

(in millions)	**2017**	2016	2015
Pretax leveraged lease income	**$25**	$25	$20
Net impact of Tax Reform Legislation	**48**	—	—
Income tax expense	**(9)**	(9)	(7)
Net leveraged lease income	**$64**	$16	$13

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 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.

The Company offsets fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. At December 31, 2017, the amount included in accounts payable in the 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 potential 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:

(in millions)	Qualifying Hedges	Pension and Other Postretirement Benefit Plans	Accumulated Other Comprehensive Income (Loss)
Balance at December 31, 2016	$(115)	$(65)	$(180)
Current period change	(4)	(5)	(9)
Balance at December 31, 2017	**$(119)**	**$(70)**	**$(189)**

NOTE 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 and PowerSecure. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2017 and no mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2018. 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, 2018, 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 and reopened to all non-union employees on January 1, 2018. This qualified pension plan is funded in accordance with requirements of ERISA. No contributions to the qualified pension plan were made for the year ended December 31, 2017 and no mandatory contributions to the Southern Company Gas qualified pension plan are anticipated for the year ending December 31, 2018. 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, 2018, 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:	**2017**	2016	2015
Pension plans			
Discount rate – benefit obligations	**4.40%**	4.58%	4.17%
Discount rate – interest costs	**3.77**	3.88	4.17
Discount rate – service costs	**4.81**	4.98	4.48
Expected long-term return on plan assets	**7.92**	8.16	8.20
Annual salary increase	**4.37**	4.37	3.59
Other postretirement benefit plans			
Discount rate – benefit obligations	**4.23%**	4.38%	4.04%
Discount rate – interest costs	**3.54**	3.66	4.04
Discount rate – service costs	**4.64**	4.85	4.39
Expected long-term return on plan assets	**6.84**	6.66	6.97
Annual salary increase	**4.37**	4.37	3.59

Assumptions used to determine benefit obligations:	**2017**	2016
Pension plans		
Discount rate	**3.80%**	4.40%
Annual salary increase	**4.32**	4.37
Other postretirement benefit plans		
Discount rate	**3.68%**	4.23%
Annual salary increase	**4.32**	4.37

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 eight 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, 2017 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate is Reached
Pre-65	6.50%	4.50%	2026
Post-65 medical	5.00	4.50	2026
Post-65 prescription	10.00	4.50	2026

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, 2017 as follows:

(in millions)	1 Percent Increase	1 Percent Decrease
Benefit obligation	$132	$113
Service and interest costs	4	3

Pension Plans

The total accumulated benefit obligation for the pension plans was $12.6 billion at December 31, 2017 and $11.3 billion at December 31, 2016. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2017 and 2016 were as follows:

(in millions)	**2017**	2016
Change in benefit obligation		
Benefit obligation at beginning of year	**$12,385**	$10,542
Acquisitions	**—**	1,244
Service cost	**293**	262
Interest cost	**455**	422
Benefits paid	**(596)**	(466)
Plan amendments	**(26)**	39
Actuarial (gain) loss	**1,297**	342
Balance at end of year	**13,808**	12,385
Change in plan assets		
Fair value of plan assets at beginning of year	**11,583**	9,234
Acquisitions	**—**	837
Actual return (loss) on plan assets	**1,953**	902
Employer contributions	**52**	1,076
Benefits paid	**(596)**	(466)
Fair value of plan assets at end of year	**12,992**	11,583
Accrued liability	**$ (816)**	$ (802)

At December 31, 2017, the projected benefit obligations for the qualified and non-qualified pension plans were $13.2 billion and $652 million, respectively. All pension plan assets are related to the qualified pension plans.

Amounts presented in the following tables exclude regulatory assets of $334 million associated with unamortized amounts in Southern Company Gas' pension plans prior to its acquisition by Southern Company on July 1, 2016.

Amounts recognized in the balance sheets at December 31, 2017 and 2016 related to the Company's pension plans consist of the following:

(in millions)	**2017**	2016
Other regulatory assets, deferred	**$ 3,273**	$ 3,207
Other current liabilities	**(53)**	(53)
Employee benefit obligations	**(763)**	(749)
Other regulatory liabilities, deferred	**(118)**	(87)
Accumulated OCI	**107**	100

Presented below are the amounts included in accumulated OCI and regulatory assets at December 31, 2017 and 2016 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 2018.

(in millions)	Prior Service Cost	Net (Gain) Loss
Balance at December 31, 2017:		
Accumulated OCI	**$ 3**	**$ 104**
Regulatory assets	**14**	**3,140**
Total	**$17**	**$3,244**
Balance at December 31, 2016:		
Accumulated OCI	$ 4	$ 96
Regulatory assets	51	3,069
Total	$55	$3,165
Estimated amortization in net periodic pension cost in 2018:		
Accumulated OCI	**$ 1**	**$ 9**
Regulatory assets	**4**	**204**
Total	**$ 5**	**$ 213**

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, 2017 and 2016 are presented in the following table:

(in millions)	Accumulated OCI	Regulatory Assets
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
Net (gain) loss	**15**	**227**
Change in prior service costs	**—**	**(26)**
Reclassification adjustments:		
Amortization of prior service costs	**(1)**	**(11)**
Amortization of net gain (loss)	**(7)**	**(155)**
Total reclassification adjustments	**(8)**	**(166)**
Total change	**7**	**35**
Balance at December 31, 2017	**$107**	**$3,155**

Components of net periodic pension cost were as follows:

(in millions)	**2017**	2016	2015
Service cost	**$ 293**	$ 262	$ 257
Interest cost	**455**	422	445
Expected return on plan assets	**(897)**	(782)	(724)
Recognized net (gain) loss	**162**	150	215
Net amortization	**12**	14	25
Net periodic pension cost	**$ 25**	$ 66	$ 218

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, 2017, estimated benefit payments were as follows:

(in millions)	Benefit Payments
2018	$ 634
2019	637
2020	663
2021	681
2022	704
2023 to 2027	3,836

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2017 and 2016 were as follows:

(in millions)	**2017**	2016
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 2,297**	$ 1,989
Acquisitions	**—**	338
Service cost	**24**	22
Interest cost	**79**	76
Benefits paid	**(136)**	(119)
Actuarial (gain) loss	**65**	(16)
Plan amendments	**3**	—
Retiree drug subsidy	**7**	7
Balance at end of year	**2,339**	2,297
Change in plan assets		
Fair value of plan assets at beginning of year	**944**	833
Acquisitions	**—**	100
Actual return (loss) on plan assets	**154**	58
Employer contributions	**84**	65
Benefits paid	**(129)**	(112)
Fair value of plan assets at end of year	**1,053**	944
Accrued liability	**$(1,286)**	$(1,353)

Amounts presented in the following tables exclude regulatory assets of $77 million associated with unamortized amounts in Southern Company Gas' other postretirement benefit plans prior to its acquisition by Southern Company on July 1, 2016.

Amounts recognized in the balance sheets at December 31, 2017 and 2016 related to the Company's other postretirement benefit plans consist of the following:

(in millions)	**2017**	2016
Other regulatory assets, deferred	**$ 382**	$ 419
Other current liabilities	**(5)**	(4)
Employee benefit obligations	**(1,281)**	(1,349)
Other regulatory liabilities, deferred	**(41)**	(41)
Accumulated OCI	**4**	7

Presented below are the amounts included in accumulated OCI and net regulatory assets (liabilities) at December 31, 2017 and 2016 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 2018.

(in millions)	Prior Service Cost	Net (Gain) Loss
Balance at December 31, 2017:		
Accumulated OCI	**$ —**	**$ 4**
Net regulatory assets	**21**	**320**
Total	**$21**	**$324**
Balance at December 31, 2016:		
Accumulated OCI	$ —	$ 7
Net regulatory assets	25	353
Total	$25	$360
Estimated amortization as net periodic postretirement benefit cost in 2018:		
Net regulatory assets	**$ 7**	**$ 14**

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, 2017 and 2016 are presented in the following table:

(in millions)	Accumulated OCI	Net Regulatory Assets (Liabilities)
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	$378
Net (gain) loss	**(3)**	**(21)**
Change in prior service costs	**—**	**3**
Reclassification adjustments:		
Amortization of prior service costs	**—**	**(6)**
Amortization of net gain (loss)	**—**	**(13)**
Total reclassification adjustments	**—**	**(19)**
Total change	**(3)**	**(37)**
Balance at December 31, 2017	**$ 4**	**$341**

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

(in millions)	**2017**	2016	2015
Service cost	**$ 24**	$ 22	$ 23
Interest cost	**79**	76	78
Expected return on plan assets	**(66)**	(60)	(58)
Net amortization	**20**	21	21
Net periodic postretirement benefit cost	**$ 57**	$ 59	$ 64

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:

(in millions)	Benefit Payments	Subsidy Receipts	Total
2018	$144	$ (7)	$137
2019	148	(8)	140
2020	151	(8)	143
2021	154	(9)	145
2022	156	(9)	147
2023 to 2027	780	(48)	732

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. Management believes the portfolio is well-diversified with no significant concentrations of risk.

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 debt.	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, and actual allocations relative to the target allocations, of Southern Company's pension plan (excluding Southern Company Gas) as of December 31, 2017 and 2016 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.

As of December 31, 2017:	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(*)	$ 2,405	$ 1,159	$—	$ —	$ 3,564	26%	31%
International equity(*)	1,555	1,403	—	—	2,958	25	25
Fixed income:						23	24
U.S. Treasury, government, and agency bonds	—	841	—	—	841		
Mortgage- and asset-backed securities	—	8	—	—	8		
Corporate bonds	—	1,201	—	—	1,201		
Pooled funds	—	650	—	—	650		
Cash equivalents and other	217	11	—	—	228		
Real estate investments	469	—	—	1,188	1,657	14	13
Special situations	—	—	—	180	180	3	1
Private equity	—	—	—	669	669	9	6
Total	$ 4,646	$ 5,273	$—	$ 2,037	$ 11,956	100%	100%

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

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	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.

The fair values of Southern Company Gas' pension plan assets for the period ended December 31, 2017 and 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. 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				
As of December 31, 2017:	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(*)	$155	$323	$—	$ —	$478
International equity(*)	—	166	—	—	166
Fixed income:					
U.S. Treasury, government, and agency bonds	—	85	—	—	85
Corporate bonds	—	39	—	—	39
Cash equivalents and other	84	25	—	48	157
Real estate investments	3	—	—	16	19
Private equity	—	—	—	1	1
Total	$242	$638	$—	$ 65	$945

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

	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(*)	$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.

The composition of Southern Company Gas' pension plan assets as of December 31, 2017 and 2016, along with the targets, is presented below:

	Target	**2017**	2016
Pension plan assets:			
Equity	53%	**65%**	69%
Fixed Income	15	**19**	20
Cash	2	**6**	1
Other	30	**10**	10
Balance at end of period	100%	**100%**	100%

The fair values of Southern Company's (excluding Southern Company Gas) other postretirement benefit plan assets as of December 31, 2017 and 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.

As of December 31, 2017:	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(*)	$132	$ 35	$—	$ —	$167	37%	40%
International equity(*)	47	76	—	—	123	23	23
Fixed income:						30	29
U.S. Treasury, government, and agency bonds	—	32	—	—	32		
Corporate bonds	—	37	—	—	37		
Pooled funds	—	55	—	—	55		
Cash equivalents and other	10	—	—	—	10		
Trust-owned life insurance	—	426	—	—	426		
Real estate investments	16	—	—	36	52	5	5
Special situations	—	—	—	5	5	1	1
Private equity	—	—	—	20	20	4	2
Total	$205	$661	$—	$ 61	$927	100%	100%

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

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	Target Allocation	Actual Allocation
	(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.

The fair values of Southern Company Gas' other postretirement benefit plan assets for the period ended December 31, 2017 and 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. 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				
As of December 31, 2017:	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	$ 69	$—	$ —	$ 72
International equity(*)	—	22	—	—	22
Fixed income:					
Pooled funds	—	24	—	—	24
Cash equivalents and other	2	—	—	1	3
Total	$ 5	$115	$—	$ 1	$121

(*) Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds.

	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(*)	$ 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.

The composition of Southern Company Gas' other postretirement benefit plan assets as of December 31, 2017 and 2016, along with the targets, is presented below:

	Target	**2017**	2016
Other postretirement benefit plan assets:			
Equity	72%	**76%**	74%
Fixed Income	24	**20**	23
Cash	1	**2**	1
Other	3	**2**	2
Total	100%	**100%**	100%

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 2017, 2016, and 2015 were $118 million, $105 million, and $92 million, respectively.

NOTE 3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

On January 20, 2017, a purported securities class action complaint was filed against Southern Company, certain of its officers, and certain former Mississippi Power 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, certain of its officers, and certain former Mississippi Power officers made materially false and misleading statements regarding the Kemper County energy facility 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. On June 12, 2017, the plaintiffs filed an amended complaint that provided additional detail about their claims, increased the purported class period by one day, and added certain other former Mississippi Power officers as defendants. On July 27, 2017, the defendants filed a motion to dismiss the plaintiffs' amended complaint with prejudice, to which the plaintiffs filed an opposition on September 11, 2017.

On February 27, 2017, Jean Vineyard filed a shareholder derivative lawsuit in the U.S. District Court for the Northern District of Georgia that names as defendants Southern Company, certain of its directors, certain of its officers, and certain former Mississippi Power officers. The complaint alleges that the defendants caused Southern Company to make false or misleading statements regarding the Kemper County energy facility cost and schedule. Further, the complaint alleges that the defendants were unjustly enriched and caused the waste of corporate assets. The plaintiff seeks to recover, on behalf of Southern Company, unspecified actual damages and, on her own behalf, attorneys' fees and costs in bringing the lawsuit. The plaintiff also seeks certain changes to Southern Company's corporate governance and internal processes. On March 27, 2017, the court deferred this lawsuit until 30 days after certain further action in the purported securities class action complaint discussed above.

On May 15, 2017, Helen E. Piper Survivor's Trust filed a shareholder derivative lawsuit in the Superior Court of Gwinnett County, State of Georgia and, on May 31, 2017, Judy Mesirov filed a shareholder derivative lawsuit in the U.S. District Court for the Northern District of Georgia. Each of these lawsuits names as defendants Southern Company, certain of its directors, certain of its officers, and certain former Mississippi Power officers. Each complaint alleges that the individual defendants, among other things, breached their fiduciary duties in connection with schedule delays and cost overruns associated with the construction of the Kemper County energy facility. Each complaint further alleges that the individual defendants authorized or failed to correct false and misleading statements regarding the Kemper County energy facility schedule and cost and failed to implement necessary internal controls to prevent harm to Southern Company. Each plaintiff seeks to recover, on behalf of Southern Company, unspecified actual damages and disgorgement of profits and, on its behalf, attorneys' fees and costs in bringing the lawsuit. Each plaintiff also seeks certain unspecified changes to Southern Company's corporate governance and internal processes. On August 15, 2017, these two shareholder derivative lawsuits were consolidated in the U.S. District Court for the Northern District of Georgia and the court deferred the consolidated case until 30 days after certain further action in the purported securities class action complaint discussed above.

Southern Company believes these legal challenges have no merit; however, an adverse outcome in any of 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, the ultimate outcome of which 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 standards for air, water, land, and protection of other natural resources, 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 governing 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 conduct studies to determine the extent of any required cleanup and have recognized the estimated costs to clean up known impacted sites in the financial statements. A liability for environmental remediation costs is recognized only when a loss is determined to be probable and reasonably estimable. The traditional electric operating companies and the natural gas distribution utilities in Illinois, New Jersey, Georgia, and Florida have all 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, 2017 and 2016 was $22 million and $17 million, respectively. 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.

Gulf Power's environmental remediation liability includes estimated costs of environmental remediation projects of approximately $52 million and $44 million as of December 31, 2017 and 2016, respectively. 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, 2017 and 2016 was $388 million and $426 million, respectively, based on the estimated cost of environmental investigation and remediation associated with known current and former manufactured gas plant 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 $2 million of the total accrued remediation costs.

The ultimate outcome of these matters cannot be determined at this time; however, as a result of the regulatory treatment for environmental remediation expenses described above, 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 2015, Georgia Power recovered approximately $18 million, based on its ownership interests, which was credited to accounts where the original costs were charged, and used to reduce rate base, fuel, and cost of service for the benefit of customers. Also in 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 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. On October 10, 2017, Alabama Power and Georgia Power filed additional lawsuits against the U.S. government in the Court of Federal Claims 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, 2015 through December 31, 2017. 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, 2017 for any potential recoveries from the pending lawsuits. The final outcome of these matters cannot be determined at this time. However, Alabama Power and Georgia Power expect to credit any recoveries back for the benefit of customers in accordance with direction from their respective PSC and, therefore, 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 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 and filed their response with the FERC in 2015.

In December 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. On May 17, 2017, the FERC accepted the traditional electric operating companies' and Southern Power's compliance filing 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.

On October 25, 2017, the FERC issued an order in response to the traditional electric operating companies' and Southern Power's June 29, 2017 triennial updated market power analysis. The FERC directed the traditional electric operating companies and Southern Power to show cause within 60 days why market-based rate authority should not be revoked in certain areas adjacent to the area presently under mitigation in accordance with the February 2, 2017 order or to provide a mitigation plan to further address market power concerns. On November 10, 2017, the traditional electric operating companies and Southern Power responded to the FERC and proposed to resolve matters by applying the alternative mitigation authorized by the February 2, 2017 order to the adjacent areas made the subject of the October 25, 2017 order.

The ultimate outcome of these matters 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.

At December 31, 2016, Alabama Power's retail return exceeded the allowed WCE range which resulted in Alabama Power establishing a $73 million Rate RSE refund liability. In accordance with an Alabama PSC order issued on February 14, 2017, Alabama Power applied the full amount of the refund to reduce the under recovered balance of Rate CNP PPA as discussed further below.

Effective in January 2017, Rate RSE increased 4.48%, or $245 million annually. At December 31, 2017, Alabama Power's actual retail return was within the allowed WCE range. On December 1, 2017, Alabama Power made its required annual Rate RSE submission to the Alabama PSC of projected data for calendar year 2018. Projected earnings were within the specified range; therefore, retail rates under Rate RSE remained unchanged for 2018.

In conjunction with Rate RSE, Alabama Power has an established retail tariff that provides for an adjustment to customer billings to recognize the impact of a change in the statutory income tax rate. As a result of Tax Reform Legislation, the application of this tariff would reduce annual retail revenue by approximately $250 million over the remainder of 2018. The ultimate outcome of this matter cannot be determined at this time.

Rate CNP PPA

Alabama Power's retail rates, approved by the Alabama PSC, provide for adjustments under Rate CNP to recognize the placing of new generating facilities into retail service. Alabama Power may also recover retail costs associated with certificated PPAs under Rate CNP PPA. On March 7, 2017, 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, 2017 through March 31, 2018. No adjustment to Rate CNP PPA is expected in 2018. As of December 31, 2017 and 2016, Alabama Power had an under recovered Rate CNP PPA balance of $12 million and $142 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, Alabama Power eliminated 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 utilized the full amount of its $73 million Rate RSE refund liability to reduce the amount of the Rate CNP PPA under recovery and reclassified 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 two to four 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 Rate CNP Compliance-related operations and maintenance expenses and depreciation generally will have no effect on net income.

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, Alabama Power reclassified $36 million of its under recovered balance in Rate CNP Compliance 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 two to four years. Alabama Power's current depreciation study became effective January 1, 2017.

On December 5, 2017, the Alabama PSC issued a consent order that Alabama Power leave in effect for 2018 the factors associated with Alabama Power's compliance costs for the year 2017, with any under-collected amount for prior years deemed recovered before any current year amounts. Any under recovered amounts associated with 2018 will be reflected in the 2019 filing. As of December 31, 2017 and 2016, Alabama Power had a deferred under recovered regulatory clause revenues balance of $17 million and $9 million, respectively.

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 accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, Alabama Power reclassified $36 million of its under recovered balance in Rate ECR 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 two to four years. Alabama Power's current depreciation study became effective January 1, 2017.

On December 5, 2017, the Alabama PSC issued a consent order that Alabama Power leave in effect for 2018 the energy cost recovery rates which began in 2017. Therefore, the Rate ECR factor as of January 1, 2018 remained at 2.015 cents per KWH. The rate will return to 5.910 cents per KWH in 2019, absent a further order from the Alabama PSC.

At December 31, 2017, Alabama Power's under recovered fuel costs totaled $25 million, which is included in other regulatory assets, current. At December 31, 2016, Alabama Power had an over recovered fuel balance of $76 million, which was 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.

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. When the reserve balance falls below $50 million, a reserve establishment charge will be activated (and the on-going reserve maintenance charge concurrently suspended) until the reserve balance reaches $75 million. 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.

In December 2017, the reserve maintenance charge was suspended and the reserve establishment charge was activated as a result of the NDR balance falling below $50 million. Alabama Power expects to collect approximately $16 million annually until the reserve balance is restored to $75 million. The NDR balance at December 31, 2017 was $38 million.

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. The regulatory asset will be amortized and recovered over the affected unit's remaining useful life, as established prior to the decision regarding early retirement through Rate CNP Compliance.

Alabama Power retired Plant Gorgas Units 6 and 7 (200 MWs) and Plant Barry Unit 3 (225 MWs) in 2015. Additionally, Alabama Power ceased using coal at Plant Barry Units 1 and 2 (250 MWs) in 2015, but such units remain available on a limited basis with natural gas as the fuel source. In April 2016, Alabama Power also 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 regulatory assets at their respective retirement dates. These regulatory assets are being 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 in April 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, 2016 as follows: (1) traditional base tariff rates by approximately $49 million; (2) Environmental Compliance Cost Recovery tariff by approximately $75 million; (3) Demand-Side Management tariffs by approximately $3 million; and (4) Municipal Franchise Fee tariff by approximately $13 million, for a total increase in base revenues of approximately $140 million. There were no changes to these tariffs in 2017.

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 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 will refund to retail customers approximately $44 million in 2018, as approved by the Georgia PSC on January 16, 2018. In 2017, Georgia Power's retail ROE was within the allowed retail ROE range, subject to review and approval by the Georgia PSC.

On January 19, 2018, the Georgia PSC issued an order on the Tax Reform Legislation, which was amended on February 16, 2018 (Tax Order). In accordance with the Tax Order, Georgia Power is required to submit its analysis of the Tax Reform Legislation and related recommendations to address the related impacts on Georgia Power's cost of service and annual revenue requirements by March 6, 2018. The ultimate outcome of this matter cannot be determined at this time.

Integrated Resource Plan

In July 2016, the Georgia PSC approved Georgia Power's triennial Integrated Resource Plan (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). In August 2016, the Plant Mitchell and Plant Kraft units were retired and 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 (REDI) 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.

In 2017, Georgia Power filed for and received certification for 510 MWs of REDI utility-scale PPAs for solar generation resources, which are expected to be in operation by the end of 2019. Georgia Power also filed for and received approval to develop several solar generation projects to fulfill the approved self-build capacity.

In the 2016 IRP, the Georgia PSC also approved recovery of costs up to $99 million through June 30, 2019 to preserve nuclear generation as an option at a future generation site in Stewart County, Georgia. On March 7, 2017, the Georgia PSC approved Georgia Power's decision to suspend work at the site due to changing economics, including lower load forecasts and fuel costs. The timing of recovery for costs incurred of approximately $50 million is expected to be determined by the Georgia PSC in a future Georgia Power rate case.

Fuel Cost Recovery

Georgia Power has established fuel cost recovery rates approved by the Georgia PSC. In 2015, the Georgia PSC approved Georgia Power's request to lower annual billings by approximately $350 million effective January 1, 2016. In May 2016, the Georgia PSC approved Georgia Power's request to further lower annual billings under an interim fuel rider by approximately $313 million effective June 1, 2016, which expired on December 31, 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. Georgia Power continues to be allowed to adjust its fuel cost recovery rates under an interim fuel rider 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.

Georgia Power's under recovered fuel balance totaled $165 million at December 31, 2017 and is included in current assets. At December 31, 2016, Georgia Power's over recovered fuel balance totaled $84 million and is included in other regulatory liabilities, current.

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

Georgia Power is accruing $30 million annually through December 31, 2019, as provided in the 2013 ARP, for incremental operating and maintenance costs of damage from major storms to its transmission and distribution facilities. Hurricanes Irma and Matthew caused significant damage to Georgia Power's transmission and distribution facilities during September 2017 and October 2016, respectively. The incremental restoration costs related to these hurricanes deferred in Georgia Power's regulatory asset for storm damage totaled approximately $260 million. The rate of storm damage cost recovery is expected to be adjusted as part of Georgia Power's next base rate case required to be filed by July 1, 2019. 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.

At December 31, 2017 and December 31, 2016, the total balance in Georgia Power's regulatory asset related to storm damage was $333 million and $206 million, respectively, with approximately $30 million included in other regulatory assets, current for both years and approximately $303 million and $176 million included in other regulatory assets, deferred, respectively.

Gulf Power

Retail Base Rate Cases

In 2013, the Florida PSC approved a settlement agreement related to Gulf Power's 2013 retail base rate case that authorized Gulf Power to reduce depreciation and record a regulatory asset up to $62.5 million from January 2014 through June 2017. In any given month, such depreciation reduction was not to 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. For 2014 and 2015, Gulf Power recognized reductions in depreciation of $8.4 million and $20.1 million, respectively. No net reduction in depreciation was recorded in 2016. In 2017, Gulf Power recognized the remaining $34.0 million reduction in depreciation.

On April 4, 2017, the Florida PSC approved a settlement agreement (2017 Rate Case Settlement Agreement) among Gulf Power and three intervenors with respect to Gulf Power's request in 2016 to increase retail base rates. Among the terms of the 2017 Rate Case Settlement Agreement, Gulf Power increased rates effective with the first billing cycle in July 2017 to provide an annual overall net customer impact of approximately $54.3 million. The net customer impact consisted of a $62.0 million increase in annual base revenues, less an annual purchased power capacity cost recovery clause credit for certain wholesale revenues of approximately $8 million through December 2019. In addition, Gulf Power continued its authorized retail ROE midpoint (10.25%) and range (9.25% to 11.25%) and is deemed to have a maximum equity ratio of 52.5% for all retail regulatory purposes. Gulf Power also began amortizing the regulatory asset associated with the investment balances remaining after the retirement of Plant Smith Units 1 and 2 (357 MWs) over 15 years effective January 1, 2018 and implemented new depreciation rates effective January 1, 2018. The 2017 Rate Case Settlement Agreement also resulted in a $32.5 million write-down of Gulf Power's ownership of Plant Scherer Unit 3 (205 MWs), which was recorded in the first quarter 2017. The remaining issues related to the inclusion of Gulf Power's investment in Plant Scherer Unit 3 in retail rates have been resolved as a result of the 2017 Rate Case Settlement Agreement, including recoverability of certain costs associated with the ongoing ownership and operation of the unit through the environmental cost recovery clause.

The 2017 Rate Case Settlement Agreement set forth a process for addressing the revenue requirement effects of the Tax Reform Legislation through a prospective change to Gulf Power's base rates. Under the terms of the 2017 Rate Case Settlement Agreement, by March 1, 2018, Gulf Power must identify the revenue requirements impacts and defer them to a regulatory asset or regulatory liability to be considered for prospective application in a change to base rates in a limited scope proceeding before the Florida PSC. In lieu of this approach, on February 14, 2018, the parties to the 2017 Rate Case Settlement Agreement filed a new stipulation and settlement agreement (2018 Tax Reform Settlement Agreement) with the Florida PSC. If approved, the 2018 Tax Reform Settlement Agreement will result in annual reductions of $18.2 million to Gulf Power's base rates and $15.6 million to Gulf Power's environmental cost recovery rates effective beginning the first calendar month following approval.

The 2018 Tax Reform Settlement Agreement also provides for a one-time refund of $69.4 million for the retail portion of unprotected (not subject to normalization) deferred tax liabilities through Gulf Power's fuel cost recovery rate over the remainder of 2018. In addition, a limited scope proceeding to address the flow back of protected deferred tax liabilities will be initiated by May 1, 2018 and Gulf Power will record a regulatory liability for the related 2018 amounts eligible to be returned to customers consistent with IRS normalization principles. Unless otherwise agreed to by the parties to the 2018 Tax Reform Settlement Agreement, amounts recorded in this regulatory liability will be refunded to retail customers in 2019 through Gulf Power's fuel cost recovery rate.

If the 2018 Tax Reform Settlement Agreement is approved, the 2017 Rate Case Settlement Agreement will be amended to increase Gulf Power's maximum equity ratio from 52.5% to 53.5% for regulatory purposes.

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

Mississippi Power

On February 7, 2018, Mississippi Power revised its annual projected Performance Evaluation Plan (PEP) filing for 2018 to reflect the impacts of the Tax Reform Legislation. The revised filing requests an increase of $26 million in annual revenues, based on a performance adjusted ROE of 9.33% and an increased equity ratio of 55%. The ultimate outcome of this matter cannot be determined at this time.

Southern Company Gas

The natural gas distribution utilities are subject to regulation and oversight by their respective state regulatory agencies for the rates charged to their customers and other matters. These agencies approve rates designed to provide 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 ROE.

The natural gas market for Atlanta Gas Light was deregulated in 1997. Accordingly, marketers, rather than a traditional utility, sell natural gas to end-use customers in Georgia and handle customer billing functions. Atlanta Gas Light earns revenue for its distribution services by charging rates to its customers based primarily on monthly fixed charges that are set by the Georgia PSC and adjusted periodically.

With the exception of Atlanta Gas Light, the natural gas distribution utilities are authorized by the relevant regulatory agencies in the states in which they serve to use natural gas cost recovery mechanisms that adjust rates to reflect changes in the wholesale cost of natural gas and ensure recovery of all costs prudently incurred in purchasing natural gas for customers. Natural gas cost recovery revenues are adjusted for differences in actual recoverable natural gas costs and amounts billed in current regulated rates. Changes in the billing factor will not have a significant effect on revenues or net income, but will affect cash flows. In addition to natural gas cost recovery mechanisms, there are 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 Note 1 under "Cost of Natural Gas" for additional information.

Regulatory Infrastructure Programs

Certain of Southern Company Gas' 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 nine to 10 years, with completion dates ranging from 2020 through 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.

Base Rate Cases

On January 31, 2018, the Illinois Commerce Commission approved a $137 million increase in Nicor Gas' annual base rate revenues, including $93 million related to the recovery of investments under Nicor Gas' infrastructure program, effective February 8, 2018, based on a ROE of 9.8%.

The Illinois Commerce Commission issued an order effective January 25, 2018 that requires utilities in the state to record the impacts of the Tax Reform Legislation, including the reduction in the corporate income tax rate to 21% and the impact of excess deferred income taxes, as a regulatory liability. On February 20, 2018, the Illinois Commerce Commission granted Nicor Gas' application for rehearing to file revised base rates and tariffs, which Nicor Gas expects to file by the end of the second quarter 2018.

On December 1, 2017, Atlanta Gas Light filed its 2018 annual rate adjustment with the Georgia PSC. If approved, Atlanta Gas Light's annual base rate revenues will increase by $22 million, effective June 1, 2018. Atlanta Gas Light will file a revised rate adjustment to incorporate the effects of the Tax Reform Legislation in the first quarter 2018. The Georgia PSC is expected to rule on the revised requested increase in the second quarter 2018.

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

Kemper County Energy Facility

Overview

The Kemper County energy facility was designed to utilize IGCC technology with an expected output capacity of 582 MWs and to be fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by Mississippi Power and situated adjacent to the Kemper County energy facility. The mine, operated by North American Coal Corporation, started commercial operation in 2013. In connection with the Kemper County energy facility construction, Mississippi Power constructed approximately 61 miles of CO_2 pipeline infrastructure for the transport of captured CO_2 for use in enhanced oil recovery.

Schedule and Cost Estimate

In 2012, the Mississippi PSC issued the 2012 MPSC CPCN Order, confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing the acquisition, construction, and operation of the Kemper County energy facility. The certificated cost estimate of the Kemper County energy facility included in the 2012 MPSC CPCN Order was $2.4 billion, net of approximately $0.57 billion for the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, AFUDC, and certain general exceptions (Cost Cap Exceptions). 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 County energy facility 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 County energy facility in service in August 2014.

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. During testing, the plant produced and captured CO_2, and produced sulfuric acid and ammonia, each of acceptable quality under the related off-take agreements. However, Mississippi Power experienced numerous challenges during the extended start-up process to achieve integrated operation of the gasifiers on a sustained basis. In May 2017, after achieving these milestones, Mississippi Power determined that a critical system component, the syngas coolers, would need replacement sooner than originally planned, which would require significant lead time and significant cost. In addition, the long-term natural gas price forecast had decreased significantly and the estimated cost of operating and maintaining the facility during the first five full years of operations had increased significantly since certification.

On June 21, 2017, the Mississippi PSC stated its intent to issue an order (which occurred on July 6, 2017) directing Mississippi Power to pursue a settlement under which the Kemper County energy facility would be operated as a natural gas plant, rather than an IGCC plant, and address all issues associated with the Kemper County energy facility (Kemper Settlement Order). The Kemper Settlement Order established a new docket for the purposes of pursuing a global settlement of the related costs (Kemper Settlement Docket). On June 28, 2017, Mississippi Power notified the Mississippi PSC that it would begin a process to suspend operations and start-up activities on the gasifier portion of the Kemper County energy facility, given the uncertainty as to its future. On February 6, 2018, the Mississippi PSC voted to approve a settlement agreement related to cost recovery for the Kemper County energy facility among Mississippi Power, the MPUS, and certain intervenors (Kemper Settlement Agreement).

At the time of project suspension in June 2017, the total cost estimate for the Kemper County energy facility was approximately $7.38 billion, including approximately $5.95 billion of costs subject to the construction cost cap, and was net of the $137 million in additional grants from the DOE for the Kemper County energy facility. In the aggregate, Mississippi Power had recorded charges to income of $3.07 billion ($1.89 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through May 31, 2017.

Given the Mississippi PSC's stated intent regarding no further rate increase for the Kemper County energy facility and the subsequent suspension, cost recovery of the gasifier portions became no longer probable; therefore, Mississippi Power recorded an additional charge to income in June 2017 of $2.8 billion ($2.0 billion after tax), which included estimated costs associated with the gasifier portions of the plant and lignite mine. During the third and fourth quarters of 2017, Mississippi Power recorded charges to income of $242 million ($206 million after tax), including $164 million for ongoing project costs, estimated mine and gasifier-related costs, and certain termination costs during the suspension period prior to conclusion of the Kemper Settlement Docket, as well as the charge associated with the Kemper Settlement Agreement discussed below. Additional pre-tax cancellation costs, including mine and plant closure and contract termination costs, currently estimated at approximately $50 million to $100 million (excluding salvage), are expected to be incurred in 2018. Mississippi Power has begun efforts to dispose of or abandon the mine and gasifier-related assets.

Rate Recovery

Kemper Settlement Agreement

On February 6, 2018, the Mississippi PSC voted to approve the Kemper Settlement Agreement. The Kemper Settlement Agreement provides for an annual revenue requirement of approximately $99.3 million for costs related to the Kemper County energy facility, which includes the impact of Tax Reform Legislation. The revenue requirement is based on (i) a fixed ROE for 2018 of 8.6% excluding any performance adjustment, (ii) a ROE for 2019 calculated in accordance with PEP, excluding the performance adjustment, (iii) for future years, a performance-based ROE calculated pursuant to PEP, and (iv) amortization periods for the related regulatory assets and liabilities of eight years and six years, respectively. The revenue requirement also reflects a disallowance related to a portion of Mississippi Power's investment in the Kemper County energy facility requested for inclusion in rate base, which was recorded in the fourth quarter 2017 as an additional charge to income of approximately $78 million ($85 million net of accumulated depreciation of $7 million) pre-tax ($48 million after tax).

Under the Kemper Settlement Agreement, retail customer rates will reflect a reduction of approximately $26.8 million annually and include no recovery for costs associated with the gasifier portion of the Kemper County energy facility in 2018 or at any future date. On February 12, 2018, Mississippi Power made the required compliance filing with the Mississippi PSC. The Kemper Settlement Agreement also requires (i) the CPCN for the Kemper County energy facility to be modified to limit it to natural gas combined cycle operation and (ii) Mississippi Power to file a reserve margin plan with the Mississippi PSC by August 2018.

As of December 31, 2017, the balances associated with the Kemper County energy facility regulatory assets and liabilities were $114 million and $26 million, respectively.

As a result of the Mississippi PSC order on February 6, 2018, rate recovery for the Kemper County energy facility is resolved, subject to any future legal challenges.

2015 Rate Case

On December 3, 2015, the Mississippi PSC issued the In-Service Asset Rate Order regarding the Kemper County energy facility assets that were commercially operational and currently providing service to customers (the transmission facilities, combined cycle, natural gas pipeline, and water pipeline) and other related costs. 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.

In connection with the implementation of the In-Service Asset Rate Order and wholesale rates, Mississippi Power began expensing certain ongoing project costs and certain retail debt carrying costs that previously were deferred and began amortizing certain regulatory assets associated with assets placed in service and consulting and legal fees over periods ranging from two years to 10 years. On July 6, 2017, the Mississippi PSC issued an order requiring Mississippi Power to establish a regulatory liability account to maintain current rates related to the Kemper County energy facility following the July 2017 completion of the amortization period for certain of these regulatory assets.

Lignite Mine and CO_2 Pipeline Facilities

Mississippi Power owns the lignite mine and equipment and mineral reserves located around the Kemper County energy facility 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 responsible for the mining operations 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. Mississippi Power expects mine reclamation to begin in 2018. In addition to the obligation to fund the reclamation activities, Mississippi Power provided working capital support to Liberty Fuels through cash advances for capital purchases, payroll, and other operating expenses.

In addition, Mississippi Power constructed the CO_2 pipeline for the planned transport of captured CO_2 for use in enhanced oil recovery and entered into an agreement with Denbury Onshore (Denbury) to purchase the captured CO_2. Denbury has the right to terminate the contract at any time because Mississippi Power did not place the Kemper IGCC in service by July 1, 2017.

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

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. The individual plaintiff 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 County energy facility 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 County energy facility; 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 County energy facility in Mississippi; and seek attorney's fees, costs, and interest. The plaintiffs also seek an injunction to prevent any Kemper County energy facility costs from being charged to customers through electric rates. On June 23, 2017, the Circuit Court ruled in favor of motions by Southern Company and Mississippi Power and dismissed the case. On July 7, 2017, the plaintiffs filed notice of an appeal. Southern Company believes this legal challenge has no merit; however, an adverse outcome in this proceeding could have a material impact on Southern Company's results of operations, financial condition, and liquidity. Southern Company intends to vigorously defend itself in this matter and the ultimate outcome of this matter cannot be determined at this time.

On June 9, 2016, Treetop, Greenleaf CO_2 Solutions, LLC (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 related to the cancelled CO_2 contract with Treetop and alleged fraudulent misrepresentation, fraudulent concealment, civil conspiracy, and breach of contract on the part of Mississippi Power, Southern Company, and SCS and sought compensatory damages of $100 million, as well as unspecified punitive damages. Southern Company, Mississippi Power, and SCS moved to compel arbitration pursuant to the terms of the CO_2 contract, which the court granted on May 4, 2017. On June 28, 2017, Treetop, Greenleaf, Tenrgys, LLC, Tellus Energy, LLC, WCOA, LLC, and Tellus Operating Group filed a claim for arbitration requesting $500 million in damages. On December 28, 2017, Mississippi Power reached a settlement agreement with Treetop, Greenleaf, Tenrgys, LLC, Tellus Energy, LLC, WCOA, LLC, and Tellus Operating Group and the arbitration was dismissed.

Nuclear Construction

Project Status

In 2009, the Georgia PSC certified construction of Plant Vogtle Units 3 and 4. In 2012, the NRC issued the related combined construction and operating licenses, which allowed full construction of the two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities to begin. Until March 2017, construction on Plant Vogtle Units 3 and 4 continued under the Vogtle 3 and 4 Agreement, which was a substantially fixed price agreement. On March 29, 2017, the EPC Contractor filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code.

In connection with the EPC Contractor's bankruptcy filing, Georgia Power, acting for itself and as agent for the Vogtle Owners, entered into the Interim Assessment Agreement with the EPC Contractor to allow construction to continue. The Interim Assessment Agreement expired on July 27, 2017 when the Vogtle Services Agreement became effective. In August 2017, following completion of comprehensive cost to complete and cancellation cost assessments, Georgia Power filed its seventeenth VCM report with the Georgia PSC, which included a recommendation to continue construction of Plant Vogtle Units 3 and 4, with Southern Nuclear serving as project manager and Bechtel serving as the primary construction contractor. On December 21, 2017, the Georgia PSC approved Georgia Power's recommendation to continue construction.

Georgia Power expects Plant Vogtle Units 3 and 4 to be placed in service by November 2021 and November 2022, respectively. Georgia Power's revised capital cost forecast for its 45.7% proportionate share of Plant Vogtle Units 3 and 4 is $8.8 billion ($7.3 billion after reflecting the impact of payments received under the Guarantee Settlement Agreement and the Customer Refunds, each as defined herein). Georgia Power's CWIP balance for Plant Vogtle Units 3 and 4 was $3.3 billion at December 31, 2017, which is net of the Guarantee Settlement Agreement payments less the Customer Refunds. Georgia Power estimates that its financing costs for construction of Plant Vogtle Units 3 and 4 will total approximately $3.1 billion, of which $1.6 billion had been incurred through December 31, 2017.

Vogtle 3 and 4 Agreement and EPC Contractor Bankruptcy

In 2008, Georgia Power, acting for itself and as agent for the Vogtle Owners, entered into the 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. Under the Toshiba Guarantee, Toshiba guaranteed certain payment obligations of the EPC Contractor, including any liability of the EPC Contractor for abandonment of work. In the first quarter 2016, Westinghouse delivered to the Vogtle Owners a total of $920 million of letters of credit from financial institutions (Westinghouse Letters of Credit) to secure a portion of the EPC Contractor's potential obligations under the Vogtle 3 and 4 Agreement.

Subsequent to the EPC Contractor bankruptcy filing, a number of subcontractors to the EPC Contractor alleged non-payment by the EPC Contractor for amounts owed for work performed on Plant Vogtle Units 3 and 4. Georgia Power, acting for itself and as agent for the Vogtle Owners, has taken actions to remove liens filed by these subcontractors through the posting of surety bonds. Related to such liens, certain subcontractors have filed, and additional subcontractors may file, actions against the EPC Contractor and the Vogtle Owners to preserve their payment rights with respect to such claims. All amounts associated with the removal of subcontractor liens and other EPC Contractor pre-petition accounts payable have been paid or accrued as of December 31, 2017.

On June 9, 2017, Georgia Power and the other Vogtle Owners and Toshiba entered into a settlement agreement regarding the Toshiba Guarantee (Guarantee Settlement Agreement). Pursuant to the Guarantee Settlement Agreement, Toshiba acknowledged the amount of its obligation was $3.68 billion (Guarantee Obligations), of which Georgia Power's proportionate share was approximately $1.7 billion. The Guarantee Settlement Agreement provided for a schedule of payments for the Guarantee Obligations beginning in October 2017 and continuing through January 2021. Toshiba made the first three payments as scheduled. On December 8, 2017, Georgia Power, the other Vogtle Owners, certain affiliates of the Municipal Electric Authority of Georgia (MEAG Power), and Toshiba entered into Amendment No. 1 to the Guarantee Settlement Agreement (Guarantee Settlement Agreement Amendment). The Guarantee Settlement Agreement Amendment provided that Toshiba's remaining payment obligations under the Guarantee Settlement Agreement were due and payable in full on December 15, 2017, which Toshiba satisfied on December 14, 2017. Pursuant to the Guarantee Settlement Agreement Amendment, Toshiba was deemed to be the owner of certain pre-petition bankruptcy claims of Georgia Power, the other Vogtle Owners, and certain affiliates of MEAG Power against Westinghouse, and Georgia Power and the other Vogtle Owners surrendered the Westinghouse Letters of Credit.

Additionally, on June 9, 2017, Georgia Power, acting for itself and as agent for the other Vogtle Owners, and the EPC Contractor entered into the Vogtle Services Agreement, which was amended and restated on July 20, 2017. On July 20, 2017, the bankruptcy court approved the EPC Contractor's motion seeking authorization to (i) enter into the Vogtle Services Agreement, (ii) assume and assign to the Vogtle Owners certain project-related contracts, (iii) join the Vogtle Owners as counterparties to certain assumed project-related contracts, and (iv) reject the Vogtle 3 and 4 Agreement. The Vogtle Services Agreement, and the EPC Contractor's rejection of the Vogtle 3 and 4 Agreement, became effective upon approval by the DOE on July 27, 2017. The Vogtle Services Agreement will continue until the start-up and testing of Plant Vogtle Units 3 and 4 are complete and electricity is generated and sold from both units. The Vogtle Services Agreement is terminable by the Vogtle Owners upon 30 days' written notice.

Effective October 23, 2017, Georgia Power, acting for itself and as agent for the other Vogtle Owners, entered into a construction completion agreement with Bechtel, whereby Bechtel will serve as the primary contractor for the remaining construction activities for Plant Vogtle Units 3 and 4 (Bechtel Agreement). Facility design and engineering remains the responsibility of the EPC Contractor under the Vogtle Services Agreement. The Bechtel Agreement is a cost reimbursable plus fee arrangement, whereby Bechtel will be reimbursed for actual costs plus a base fee and an at-risk fee, which is subject to adjustment based on Bechtel's performance against cost and schedule targets. Each Vogtle Owner is severally (not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to Bechtel under the Bechtel Agreement. The Vogtle Owners may terminate the Bechtel Agreement at any time for their convenience, provided that the Vogtle Owners will be required to pay amounts related to work performed prior to the termination (including the applicable portion of the base fee), certain termination-related costs, and, at certain stages of the work, the applicable portion of the at-risk fee. Bechtel may terminate the Bechtel Agreement under certain circumstances, including certain Vogtle Owner suspensions of work, certain breaches of the Bechtel Agreement by the Vogtle Owners, Vogtle Owner insolvency, and certain other events. Pursuant to the Loan Guarantee Agreement between Georgia Power and the DOE, Georgia Power is required to obtain the DOE's approval of the Bechtel Agreement prior to obtaining any further advances under the Loan Guarantee Agreement.

On November 2, 2017, the Vogtle Owners entered into an amendment to their joint ownership agreements for Plant Vogtle Units 3 and 4 (as amended, Vogtle Joint Ownership Agreements) to provide for, among other conditions, additional Vogtle Owner approval requirements. Pursuant to the Vogtle Joint Ownership Agreements, the holders of at least 90% of the ownership interests in Plant Vogtle Units 3 and 4 must vote to continue construction if certain adverse events occur, including (i) the bankruptcy of Toshiba; (ii) termination or rejection in bankruptcy of certain agreements, including the Vogtle Services Agreement or the Bechtel Agreement; (iii) the Georgia PSC or Georgia Power determines that any of Georgia Power's costs relating to the construction of Plant Vogtle Units 3 and 4 will not be recovered in retail rates because such costs are deemed unreasonable or imprudent; or (iv) an increase in the construction budget contained in the seventeenth VCM report of more than $1 billion or extension of the project schedule contained in the seventeenth VCM report of more than one year. In addition, pursuant to the Vogtle Joint Ownership Agreements, the required approval of holders of ownership interests in Plant Vogtle Units 3 and 4 is at least (i) 90% for a change of the primary construction contractor and (ii) 67% for material amendments to the Vogtle Services Agreement or agreements with Southern Nuclear or the primary construction contractor, including the Bechtel Agreement. The Vogtle Joint Ownership Agreements also confirm that the Vogtle Owners' sole recourse against Georgia Power or Southern Nuclear for any action or inaction in connection with their performance as agent for the Vogtle Owners is limited to removal of Georgia Power and/or Southern Nuclear as agent, except in cases of willful misconduct.

Regulatory Matters

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 up to the certified capital cost of $4.418 billion. As of December 31, 2017, Georgia Power had recovered approximately $1.6 billion of financing costs. On January 30, 2018, Georgia Power filed to decrease the NCCR tariff by approximately $50 million, effective April 1, 2018, pending Georgia PSC approval. The decrease reflects the payments received under the Guarantee Settlement Agreement, refunds to customers ordered by the Georgia PSC aggregating approximately $188 million (Customer Refunds), and the estimated effects of Tax Reform Legislation. The Customer Refunds were recognized as a regulatory liability as of December 31, 2017 and will be paid in three installments of $25 to each retail customer no later than the third quarter 2018.

Georgia Power is required to file semi-annual VCM reports with the Georgia PSC by February 28 and August 31 each year. In October 2013, in connection with the eighth VCM report, the Georgia PSC approved a stipulation (2013 Stipulation) between Georgia Power and the staff of the Georgia PSC to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate in accordance with the 2009 certification order until the completion of Plant Vogtle Unit 3, or earlier if deemed appropriate by the Georgia PSC and Georgia Power.

On December 20, 2016, the Georgia PSC voted to approve a settlement agreement (Vogtle Cost Settlement Agreement) resolving certain prudency matters in connection with the fifteenth VCM report. On December 21, 2017, the Georgia PSC voted to approve (and issued its related order on January 11, 2018) certain recommendations made by Georgia Power in the seventeenth VCM report and modifying the Vogtle Cost Settlement Agreement. The Vogtle Cost Settlement Agreement, as modified by the January 11, 2018 order, resolved the following regulatory matters related to Plant Vogtle Units 3 and 4: (i) none of the $3.3 billion of costs incurred through December 31, 2015 and reflected in the fourteenth VCM report should be disallowed from rate base on the basis of imprudence; (ii) the Contractor Settlement Agreement was reasonable and prudent and none of the amounts paid pursuant to the Contractor Settlement Agreement should be disallowed from rate base on the basis of imprudence; (iii) (a) capital costs incurred up to $5.680 billion would be presumed to be reasonable and prudent with the burden of proof on any party challenging such costs, (b) Georgia Power would have the burden to show that any capital costs above $5.680 billion were prudent, and (c) a revised capital cost forecast of $7.3 billion (after reflecting the impact of payments received under the Guarantee Settlement Agreement and Customer Refunds) is found reasonable; (iv) construction of Plant Vogtle Units 3 and 4 should be completed, with Southern Nuclear serving as project manager and Bechtel as primary contractor; (v) approved and deemed reasonable Georgia Power's revised schedule placing Plant Vogtle Units 3 and 4 in service in November 2021 and November 2022, respectively; (vi) confirmed that the revised cost forecast does not represent a cost cap and that prudence decisions on cost recovery will be made at a later date, consistent with applicable Georgia law; (vii) reduced the ROE used to calculate the NCCR tariff (a) from 10.95% (the ROE rate setting point authorized by the Georgia PSC in the 2013 ARP) to 10.00% effective January 1, 2016, (b) from 10.00% to 8.30%, effective January 1, 2020, and (c) from 8.30% to 5.30%, effective January 1, 2021 (provided that the ROE in no case will be less than Georgia Power's average cost of long-term debt); (viii) reduced the ROE used for AFUDC equity for Plant Vogtle Units 3 and 4 from 10.00% to Georgia Power's average cost of long-term debt, effective January 1, 2018; and (ix) agreed that upon Unit 3 reaching commercial operation, retail base rates would be adjusted to include carrying costs on those capital costs deemed prudent in the Vogtle Cost Settlement Agreement. The January 11, 2018 order also stated that if Plant Vogtle Units 3 and 4 are not commercially operational by June 1, 2021 and June 1, 2022, respectively, the ROE used to calculate the NCCR tariff will be further reduced by 10 basis points each month (but not lower than Georgia Power's average cost of long-term debt) until the respective unit is commercially operational. The ROE reductions negatively impacted earnings by approximately $20 million in 2016 and $25 million in 2017 and are estimated to have negative earnings impacts of approximately $120 million in 2018 and an aggregate of $585 million from 2019 to 2022. In its January 11, 2018 order, the Georgia PSC stated if other certain conditions and assumptions upon which Georgia Power's seventeenth VCM report are based do not materialize, both Georgia Power and the Georgia PSC reserve the right to reconsider the decision to continue construction.

On February 12, 2018, Georgia Interfaith Power & Light, Inc. and Partnership for Southern Equity, Inc. filed a petition appealing the Georgia PSC's January 11, 2018 order with the Fulton County Superior Court. Georgia Power believes the appeal has no merit; however, an adverse outcome in this appeal could have a material impact on Southern Company's results of operations, financial condition, and liquidity.

The IRS allocated PTCs to each of Plant Vogtle Units 3 and 4, which originally required the applicable unit to be placed in service before 2021. Under the Bipartisan Budget Act of 2018, Plant Vogtle Units 3 and 4 continue to qualify for PTCs. The nominal value of Georgia Power's portion of the PTCs is approximately $500 million per unit.

In its January 11, 2018 order, the Georgia PSC also approved $542 million of capital costs incurred during the seventeenth VCM reporting period (January 1, 2017 to June 30, 2017). The Georgia PSC has approved seventeen VCM reports covering the periods through June 30, 2017, including total construction capital costs incurred through that date of $4.4 billion. Georgia Power expects to file its eighteenth VCM report on February 28, 2018 requesting approval of approximately $450 million of construction capital costs (before payments received under the Guarantee Settlement Agreement and the Customer Refunds) incurred from July 1, 2017 through December 31, 2017. Georgia Power's CWIP balance for Plant Vogtle Units 3 and 4 was approximately $4.8 billion as of December 31, 2017, or $3.3 billion net of payments received under the Guarantee Settlement Agreement and the Customer Refunds.

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

Cost and Schedule

Georgia Power's approximate proportionate share of the remaining estimated capital cost to complete Plant Vogtle Units 3 and 4 with in service dates of November 2021 and November 2022, respectively, is as follows:

(in billions)	
Project capital cost forecast	$ 7.3
Net investment as of December 31, 2017	(3.4)
Remaining estimate to complete	**$ 3.9**

Note: Excludes financing costs capitalized through AFUDC and is net of payments received under the Guarantee Settlement Agreement and the Customer Refunds.

Georgia Power estimates that its financing costs for construction of Plant Vogtle Units 3 and 4 will total approximately $3.1 billion, of which $1.6 billion had been incurred through December 31, 2017.

As construction continues, challenges with management of contractors, subcontractors, and vendors, labor productivity and availability, fabrication, delivery, assembly, and installation of plant systems, structures, and components (some of which are based on new technology and have not yet operated in the global nuclear industry at this scale), or other issues could arise and change the projected schedule and estimated cost.

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. 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, 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.

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

Other Matters

As of December 31, 2017, Georgia Power had borrowed $2.6 billion related to Plant Vogtle Units 3 and 4 costs through the Loan Guarantee Agreement and a multi-advance credit facility among Georgia Power, the DOE, and the FFB, which provides for borrowings of up to $3.46 billion, subject to the satisfaction of certain conditions. On September 28, 2017, the DOE issued a conditional commitment to

Georgia Power for up to approximately $1.67 billion in additional guaranteed loans under the Loan Guarantee Agreement. This conditional commitment expires on June 30, 2018, subject to any further extension approved by the DOE. Final approval and issuance of these additional loan guarantees by the DOE cannot be assured and are subject to the negotiation of definitive agreements, completion of due diligence by the DOE, receipt of any necessary regulatory approvals, and satisfaction of other conditions. See Note 6 under "DOE Loan Guarantee Borrowings" for additional information, including applicable covenants, events of default, mandatory prepayment events, and conditions to borrowing.

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

Other Matters

A wholly-owned subsidiary of Southern Company Gas owns and operates a natural gas storage facility consisting of two salt dome caverns in Louisiana. Periodic integrity tests are required in accordance with rules of the Louisiana Department of Natural Resources (DNR). In August 2017, in connection with an ongoing integrity project, updated seismic mapping indicated the proximity of one of the caverns to the edge of the salt dome may be less than the required minimum and could result in Southern Company Gas retiring the cavern early. At December 31, 2017, the facility's property, plant, and equipment had a net book value of $112 million, of which the cavern itself represents approximately 20%. A potential early retirement of this cavern is dependent upon several factors including compliance with an order from the Louisiana DNR detailing the requirements to place the cavern back in service, which includes, among other things, obtaining core samples to determine the composition of the sheath surrounding the edge of the salt dome.

The cavern continues to maintain its pressures and overall structural integrity. These events were considered in connection with Southern Company Gas' annual long-lived asset impairment analysis, which determined there was no impairment as of December 31, 2017. Any changes in results of monitoring activities, rates at which expiring capacity contracts are re-contracted, timing of placing the cavern back in service, or Louisiana DNR requirements could trigger impairment. Further, early retirement of the cavern could trigger impairment of other long-lived assets associated with the natural gas storage facility. The ultimate outcome of this matter cannot be determined at this time, but could have a significant impact on Southern Company's financial statements.

NOTE 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: Oglethorpe Power Corporation (OPC), MEAG Power, the City of Dalton, Georgia, acting by and through its Board of Water, Light, and Sinking Fund Commissioners, doing business as Dalton Utilities, Florida Power & Light Company, and Jacksonville Electric Authority. In addition, Georgia Power has joint ownership agreements with OPC for the Rocky Mountain facilities. In August 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. Southern Company Gas has a 50% undivided ownership interest in the Dalton Pipeline jointly with The Williams Companies, Inc.

At December 31, 2017, Alabama Power's, Georgia Power's, Southern Power's, and Southern Company Gas' 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%	$ 3,564	$ 2,141	$ 70
Plant Hatch (nuclear)	50.1	1,321	595	87
Plant Miller (coal) Units 1 and 2	91.8	1,717	619	54
Plant Scherer (coal) Units 1 and 2	8.4	261	93	8
Plant Wansley (coal)	53.5	1,053	335	72
Rocky Mountain (pumped storage)	25.4	182	132	—
Plant Stanton (combined cycle) Unit A	65.0	155	55	—
Dalton Pipeline (natural gas pipeline)	50.0	241	2	13

Georgia Power also owns 45.7% of Plant Vogtle Units 3 and 4, which are currently under construction and had a CWIP balance of $3.3 billion as of December 31, 2017. See Note 3 under "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 entered into an agreement to lease its 50% undivided ownership in the Dalton Pipeline that became effective when it was placed in service on August 1, 2017. Under the lease, Southern Company Gas will receive approximately $26 million annually for an initial term of 25 years. The lessee is responsible for maintaining the pipeline during the lease term and for providing service to transportation customers under its FERC-regulated tariff.

NOTE 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.

Federal Tax Reform Legislation

Following the enactment of the Tax Reform Legislation, the SEC staff issued Staff Accounting Bulletin 118 – "Income Tax Accounting Implications of the Tax Cuts and Jobs Act" (SAB 118), which provides for a measurement period of up to one year from the enactment date to complete accounting under GAAP for the tax effects of the legislation. Due to the complex and comprehensive nature of the enacted tax law changes, and their application under GAAP, Southern Company considers all amounts recorded in the financial statements as a result of the Tax Reform Legislation to be "provisional" as discussed in SAB 118 and subject to revision. Southern Company is awaiting additional guidance from industry and income tax authorities in order to finalize its accounting. The ultimate impact of the Tax Reform Legislation on deferred income tax assets and liabilities and the related regulatory assets and liabilities cannot be determined at this time. See Note 3 under "Regulatory Matters" for additional information.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

(in millions)	**2017**	2016	2015
Federal —			
Current	**$ (62)**	$1,184	$ (177)
Deferred	**(6)**	(342)	1,266
	(68)	842	1,089
State —			
Current	**37**	(108)	(33)
Deferred	**173**	217	138
	210	109	105
Total	**$142**	$ 951	$1,194

Net cash payments (refunds) for income taxes in 2017, 2016, and 2015 were $(410) million, $(148) million, and $(9) million, respectively.

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:

(in millions)	**2017**	2016
Deferred tax liabilities —		
Accelerated depreciation	**$ 10,267**	$ 15,392
Property basis differences	**955**	2,708
Leveraged lease basis differences	**251**	314
Employee benefit obligations	**516**	737
Premium on reacquired debt	**54**	89
Regulatory assets associated with employee benefit obligations	**1,046**	1,584
Regulatory assets associated with AROs	**1,225**	1,781
Other	**697**	907
Total	**15,011**	23,512
Deferred tax assets —		
Federal effect of state deferred taxes	**326**	597
Employee benefit obligations	**1,307**	1,868
Over recovered fuel clause	**—**	66
Other property basis differences	**446**	401
Deferred costs	**69**	100
ITC carryforward	**2,420**	1,974
Federal NOL carryforward	**518**	1,084
Unbilled revenue	**57**	92
Other comprehensive losses	**84**	152
AROs	**1,197**	1,732
Estimated Loss on Kemper IGCC	**722**	484
Deferred state tax assets	**328**	266
Regulatory liability associated with the Tax Reform Legislation (not subject to normalization)	**465**	—
Other	**485**	679
Total	**8,424**	9,495
Valuation allowance	**(149)**	(23)
Total deferred income taxes	**6,736**	14,040
Portion included in accumulated deferred tax assets	**(106)**	(52)
Accumulated deferred income taxes	**$ 6,842**	$ 14,092

The implementation of the Tax Reform Legislation significantly reduced accumulated deferred income taxes, partially offset by bonus depreciation provisions in the Protecting Americans from Tax Hikes Act. The Tax Reform Legislation also significantly reduced tax-related regulatory assets and increased tax-related regulatory liabilities.

At December 31, 2017, the tax-related regulatory assets to be recovered from customers were $825 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, 2017, the tax-related regulatory liabilities to be credited to customers were $7.3 billion. 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 and the natural gas distribution utilities 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 2017, $22 million in 2016, and $21 million in 2015. 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 $57 million in 2017, $37 million in 2016, and $19 million in 2015. Also, Southern Power received cash related to federal ITCs under the renewable energy incentives of $162 million for the year ended December 31, 2015. No cash was received related to these incentives in 2017 and 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 $18 million in 2017, $173 million in 2016, and $54 million in 2015. See "Unrecognized Tax Benefits" below for further information.

Tax Credit Carryforwards

At December 31, 2017, Southern Company had federal ITC and PTC carryforwards (primarily related to Southern Power) which are expected to result in $2.1 billion of federal income tax benefits. The federal ITC carryforwards begin expiring in 2034 but are expected to be fully utilized by 2027. The PTC carryforwards begin expiring in 2032 but are expected to be fully utilized by 2027. The acquisition of additional renewable projects 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 approximately $318 million, which will expire between 2020 and 2027 but are expected to be fully utilized.

Net Operating Loss

After carrying back portions of the federal NOL generated in 2016, Southern Company had a consolidated federal NOL carryforward of approximately $2.3 billion at December 31, 2017. The federal NOL will begin expiring in 2037 but is expected to be fully utilized by 2019. The ultimate outcome of this matter cannot be determined at this time.

At December 31, 2017, the state NOL carryforwards for Southern Company's subsidiaries were as follows:

Jurisdiction	Approximate NOL Carryforwards	Approximate Net State Income Tax Benefit	Tax Year NOL Begins Expiring
	(in millions)		
Mississippi	$2,890	$ 114	2032
Oklahoma	986	47	2036
Georgia	524	23	2019
New York	229	13	2036
New York City	209	15	2036
Florida	304	13	2034
Other states	465	24	Various
Total	$5,607	$ 249	

Effective Tax Rate

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

	2017	2016	2015
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**12.5**	2.1	1.9
Employee stock plans dividend deduction	**(4.1)**	(1.2)	(1.2)
Non-deductible book depreciation	**3.1**	0.9	1.2
AFUDC-Equity	**(2.6)**	(2.0)	(2.2)
Non-deductible equity portion on Kemper IGCC write-off	**15.7**	—	—
ITC basis difference	**(1.7)**	(5.0)	(1.5)
Federal PTCs	**(12.1)**	(1.2)	—
Amortization of ITC	**(4.2)**	(0.9)	(0.5)
Tax Reform Legislation	**(25.6)**	—	—
Other	**(2.7)**	(0.4)	0.2
Effective income tax rate	**13.3%**	27.3%	32.9%

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. However, in 2017, the effective tax rate was primarily lower due to the remeasurement of deferred income taxes resulting from the Tax Reform Legislation.

In March 2016, the FASB issued ASU 2016–09, which changed 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.

Legal Entity Reorganization

In September 2017, Southern Power began a legal entity reorganization of various direct and indirect subsidiaries that own and operate substantially all of its solar facilities, including certain subsidiaries owned in partnership with various third parties. The reorganization included the purchase of all of the redeemable noncontrolling interests, representing 10% of the membership interests, in Southern Turner Renewable Energy, LLC. The reorganization is expected to be substantially completed in the first quarter 2018 and is expected to result in estimated tax benefits totaling between $50 million and $55 million related to certain changes in state apportionment rates and net operating loss carryforward utilization that will be recorded in the first quarter 2018. The ultimate outcome of this matter cannot be determined at this time.

Unrecognized Tax Benefits

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

(in millions)	**2017**	2016	2015
Unrecognized tax benefits at beginning of year	**$ 484**	$433	$170
Tax positions increase from current periods	**10**	45	43
Tax positions increase from prior periods	**10**	21	240
Tax positions decrease from prior periods	**(196)**	(15)	(20)
Reductions due to settlements	**(290)**	—	—
Balance at end of year	**$ 18**	$484	$433

The tax positions increase from current and prior periods for 2017 and 2016 relate primarily to state tax benefits and charitable contribution carryforwards that were impacted as a result of the settlement of R&E expenditures associated with the Kemper County energy facility, as well as deductions for R&E expenditures associated with the Kemper County energy facility. The tax positions decrease from prior periods for 2017 and 2016, and the reductions due to settlements for 2017, relate primarily to the settlement of R&E expenditures associated with the Kemper County energy facility and federal income tax benefits from deferred ITCs. See Note 3 under "Kemper County Energy Facility" and "Section 174 Research and Experimental Deduction" herein for more information.

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

(in millions)	**2017**	2016	2015
Tax positions impacting the effective tax rate	**$18**	$ 20	$ 10
Tax positions not impacting the effective tax rate	**—**	464	423
Balance of unrecognized tax benefits	**$18**	$484	$433

The tax positions impacting the effective tax rate primarily relate to state tax benefits and charitable contribution carryforwards that were impacted as a result of the settlement of R&E expenditures associated with the Kemper County energy facility and Southern Company's estimate of the uncertainty related to the amount of those benefits. The tax positions not impacting the effective tax rate for 2016 and 2015 relate to deductions for R&E expenditures associated with the Kemper County energy facility. See "Section 174 Research and Experimental Deduction" 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 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 2016. Southern Company is a participant in the Compliance Assurance Process of the IRS. However, the pre-Merger Southern Company Gas 2014, 2015, and June 30, 2016 federal tax returns are currently under audit. 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 has reflected deductions for R&E expenditures related to the Kemper County energy facility 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, which was approved on September 8, 2017 by the U.S. Congress Joint Committee on Taxation, resolving a methodology for these deductions. As a result of this approval, Southern Company recognized $176 million of previously unrecognized tax benefits and reversed $36 million of associated accrued interest.

NOTE 6. FINANCING

Securities Due Within One Year

A summary of scheduled maturities of securities due within one year at December 31 was as follows:

(in millions)	**2017**	2016
Senior notes	**$2,354**	$1,995
Other long-term debt	**1,420**	485
Revenue bonds(*)	**90**	76
Capitalized leases	**31**	32
Unamortized debt issuance expense/discount	**(3)**	(1)
Total	**$3,892**	$2,587

(*) Includes $50 million in revenue bonds classified as short term at December 31, 2017 that were remarketed in an index rate mode subsequent to December 31, 2017. Also includes $40 million in pollution control revenue bonds classified as short term since they are variable rate demand obligations supported by short-term credit facilities; however, the final maturity dates range from 2020 to 2028.

Maturities through 2022 applicable to total long-term debt are as follows: $3.9 billion in 2018; $3.2 billion in 2019; $3.2 billion in 2020; $3.1 billion in 2021; and $2.2 billion in 2022.

Bank Term Loans

Southern Company and certain of its subsidiaries have entered into various bank term loan agreements. Unless otherwise stated, the proceeds of these loans were used to repay existing indebtedness and for general corporate purposes, including working capital and, for the subsidiaries, their continuous construction programs.

At December 31, 2017, Southern Company, Alabama Power, Georgia Power, Mississippi Power, and Southern Power Company had outstanding bank term loans totaling $450 million, $45 million, $250 million, $900 million, and $420 million, respectively, of which $1.5 billion are reflected in the statements of capitalization as long-term debt and $600 million are reflected in the balance sheet as notes payable. 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 were reflected in the statements of capitalization as long-term debt and $100 million were reflected in the balance sheet as notes payable.

In June 2017, Southern Company entered into two $100 million aggregate principal amount short-term floating rate bank term loan agreements, which mature on June 21, 2018 and June 29, 2018 and bear interest based on one-month LIBOR.

In August 2017, Southern Company borrowed $250 million pursuant to a short-term uncommitted bank credit arrangement, which bears interest at a rate agreed upon by Southern Company and the bank from time to time and is payable on no less than 30 days' demand by the bank.

In June 2017, Georgia Power entered into two short-term floating rate bank loans in aggregate principal amounts of $50 million and $150 million, with maturity dates of December 1, 2017 and May 31, 2018, respectively, and one long-term floating rate bank loan of $100 million, with a maturity date of June 28, 2018, which was amended in August 2017 to extend the maturity date to October 26, 2018. These loans bear interest based on one-month LIBOR. Also in June 2017, Georgia Power borrowed $500 million pursuant to a short-term uncommitted bank credit arrangement, which bears interest at a rate agreed upon by Georgia Power and the bank from time to time and is payable on no less than 30 days' demand by the bank.

In August 2017, Georgia Power repaid its $50 million floating rate bank loan due December 1, 2017 and $250 million of the $500 million aggregate principal amount outstanding pursuant to its uncommitted bank credit arrangement. In December 2017, Georgia Power repaid the remaining $250 million aggregate principal amount outstanding pursuant to its uncommitted bank credit arrangement.

In March 2017, Gulf Power extended the maturity of its $100 million short-term floating rate bank loan bearing interest based on one-month LIBOR from April 2017 to October 2017 and subsequently repaid the loan in May 2017.

In June 2017, Mississippi Power prepaid $300 million of the outstanding principal amount under its $1.2 billion unsecured term loan, which matures on March 30, 2018.

In September 2017, Southern Power amended its $60 million aggregate principal amount floating rate term loan to, among other things, increase the aggregate principal amount to $100 million and extend the maturity date from September 2017 to October 2018.

The outstanding bank loans as of December 31, 2017 have covenants that limit debt levels to a percentage of total capitalization. The percentage is 70% for Southern Company and 65% for Alabama Power, Georgia 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 and other hybrid securities. 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, 2017, each of Southern Company, Alabama Power, Georgia 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 the Loan Guarantee Agreement in 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.

On July 27, 2017, Georgia Power entered into an amendment to the Loan Guarantee Agreement (LGA Amendment) in connection with the DOE's consent to Georgia Power's entry into the Vogtle Services Agreement and the related intellectual property licenses (IP Licenses).

Under the terms of the Loan Guarantee Agreement, upon termination of the Vogtle 3 and 4 Agreement, further advances are conditioned upon the DOE's approval of any agreements entered into in replacement of the Vogtle 3 and 4 Agreement. Under the terms of the LGA Amendment, Georgia Power will not request any advances unless and until certain conditions are satisfied, including (i) receipt of the DOE's approval of the Bechtel Agreement (together with the Vogtle Services Agreement and the IP Licenses, the Replacement EPC Arrangements) and (ii) Georgia Power's entry into a further amendment to the Loan Guarantee Agreement with the DOE to reflect the Replacement EPC Arrangements.

Proceeds of advances made under the FFB Credit Facility are used to reimburse Georgia Power for 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.

On September 28, 2017, the DOE issued a conditional commitment to Georgia Power for up to approximately $1.67 billion of additional guaranteed loans under the Loan Guarantee Agreement. This conditional commitment expires on June 30, 2018, subject to any further extension approved by the DOE. Final approval and issuance of these additional loan guarantees by the DOE cannot be assured and are subject to the negotiation of definitive agreements, completion of due diligence by the DOE, receipt of any necessary regulatory approvals, and satisfaction of other conditions.

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.

In addition to the conditions described above, 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.

Upon satisfaction of all conditions described above, 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%.

At both December 31, 2017 and 2016, Georgia Power had $2.6 billion of borrowings outstanding under the FFB Credit Facility.

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 Services Agreement or rejection of the Vogtle Services Agreement in bankruptcy if Georgia Power does not maintain access to intellectual property rights under the IP Licenses; (ii) a decision by Georgia Power not to continue construction of Plant Vogtle Units 3 and 4; (iii) cancellation of Plant Vogtle Units 3 and 4 by the Georgia PSC, or by Georgia Power if authorized by the Georgia PSC; and (iv) 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. In addition, if Georgia Power discontinues construction of Plant Vogtle Units 3 and 4, Georgia Power would be obligated to immediately repay a portion of the outstanding borrowings under the FFB Credit Facility to the extent such outstanding borrowings exceed 70% of Eligible Project Costs, net of the proceeds received by Georgia Power under the Guarantee Settlement Agreement. Georgia Power also may voluntarily prepay outstanding borrowings under the FFB Credit Facility. Under the FFB Credit Facility, 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 $4.0 billion of senior notes in 2017. Southern Company issued $0.3 billion and its subsidiaries issued a total of $3.7 billion. The proceeds of Southern Company's issuances were used to repay short-term indebtedness and for other 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. A portion of the proceeds of Gulf Power's senior note issuances was used to redeem all of Gulf Power's outstanding shares of preference stock. See "Redeemable Preferred Stock of Subsidiaries" herein for additional information.

At December 31, 2017 and 2016, Southern Company and its subsidiaries had a total of $35.1 billion and $33.0 billion, respectively, of senior notes outstanding. At December 31, 2017 and 2016, Southern Company had a total of $10.2 billion and $10.3 billion, respectively, of senior notes outstanding. These amounts include senior notes due within one year.

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 stockholders of such subsidiary.

Junior Subordinated Notes

At December 31, 2017 and 2016, Southern Company and its subsidiaries had a total of $3.6 billion and $2.4 billion, respectively, of junior subordinated notes outstanding.

In June 2017, Southern Company issued $500 million aggregate principal amount of Series 2017A 5.325% Junior Subordinated Notes due June 21, 2057. The proceeds were used to repay short-term indebtedness and for other general corporate purposes.

In November 2017, Southern Company issued $450 million aggregate principal amount of Series 2017B 5.25% Junior Subordinated Notes due December 1, 2077. The proceeds were used to repay short-term indebtedness and for other general corporate purposes.

In September 2017, Georgia Power issued $270 million aggregate principal amount of Series 2017A 5.00% Junior Subordinated Notes due October 1, 2077. The proceeds were used to redeem all outstanding shares of Georgia Power's preferred and preference stock. See "Redeemable Preferred Stock of Subsidiaries" herein for additional information.

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, 2017 and 2016, which includes pollution control revenue bonds classified as 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 (Pivotal Utility Holdings), 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 each issuance then are loaned to Southern Company Gas. The amount of gas facility revenue bonds outstanding at December 31, 2017 and 2016 was $200 million.

The Elizabethtown Gas asset sale agreement requires that bonds representing $180 million of the total that are currently eligible for redemption at par be redeemed on or prior to consummation of the sale. The ultimate outcome of this matter cannot be determined at this time. See Note 12 under "Southern Company Gas – Proposed Sale of Elizabethtown Gas and Elkton Gas" for additional information.

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 County energy facility and related facilities.

Mississippi Power had $50 million of such obligations outstanding related to tax-exempt revenue bonds at December 31, 2017 and 2016. Such amounts are reflected in the statements of capitalization as other long-term debt.

First Mortgage Bonds

Nicor Gas, a subsidiary of Southern Company Gas, had $1.0 billion and $625 million of first mortgage bonds outstanding at December 31, 2017 and 2016, respectively. These bonds have been issued with maturities ranging from 2019 to 2057. 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.

On August 10, 2017, Nicor Gas issued $100 million aggregate principal amount of First Mortgage Bonds 3.03% Series due August 10, 2027 and $100 million aggregate principal amount of First Mortgage Bonds 3.62% Series due August 10, 2037. On November 1, 2017, Nicor Gas issued $100 million aggregate principal amount of First Mortgage Bonds 3.85% Series due August 10, 2047 and $100 million aggregate principal amount of First Mortgage Bonds 4.00% Series due August 10, 2057. The proceeds were used to repay short-term indebtedness incurred under the Nicor Gas commercial paper program and for other working capital needs.

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 outstanding as of December 31, 2017 and 2016, 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, 2017 and 2016, trust preferred securities of $200 million were outstanding.

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 County energy facility, which resulted in a capital lease obligation of $74 million at December 31, 2016. Following the suspension of the Kemper IGCC, Mississippi Power entered into an asset purchase and settlement agreement in December 2017 with the lessor, which terminated the capital lease obligation. See Note 3 under "Kemper County Energy Facility" for additional information.

At December 31, 2017 and 2016, the capitalized lease obligations for Georgia Power's corporate headquarters building were $22 million and $28 million, respectively, with an annual interest rate of 7.9%.

At December 31, 2017 and 2016, a subsidiary of Southern Company had capital lease obligations of approximately $177 million and $29 million, respectively, for an office building and certain computer equipment including desktops, laptops, servers, printers, and storage devices with annual interest rates that range from 1.5% to 4.7%.

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, 2017.

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.

On October 4, 2017, Mississippi Power executed agreements with its largest retail customer, Chevron Products Company (Chevron), to continue providing retail service to the Chevron refinery in Pascagoula, Mississippi through 2038, subject to the approval of the Mississippi PSC. The agreements grant Chevron a security interest in the co-generation assets, with a net book value of approximately $93 million, located at Chevron's refinery that is exercisable upon the occurrence of (i) certain bankruptcy events or (ii) other events of default coupled with specific reductions in steam output at the facility and a downgrade of Mississippi Power's credit rating to below investment grade by two of the three rating agencies.

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.

Under the terms of the PPA and the expansion PPA for Southern Power's Mankato project, which was acquired in 2016, approximately $442 million of assets, primarily related to property, plant, and equipment, are subject to lien at December 31, 2017. See Note 12 under "Southern Power" for additional information.

During 2015, Southern Power indirectly acquired a 51% membership interest in RE Roserock LLC (Roserock), the owner of the Roserock solar facility in Pecos County, Texas. Roserock is in a litigation dispute with McCarthy Building Companies, Inc. (McCarthy) regarding damage to certain solar panels during installation. In connection therewith, Roserock is withholding payments of approximately $26 million from

McCarthy, and McCarthy has filed mechanic's liens on the Roserock facility for the same amount. Southern Power intends to vigorously pursue its claims against McCarthy and defend against McCarthy's claims, the ultimate outcome of which cannot be determined at this time.

Bank Credit Arrangements

At December 31, 2017, committed credit arrangements with banks were as follows:

	Expires						Executable Term Loans		Expires Within One Year	
Company	2018	2019	2020	2022	Total	Unused	One Year	Two Years	Term Out	No Term Out
(in millions)										
Southern Company[a]	$ —	$ —	$ —	$2,000	$2,000	$1,999	$ —	$ —	$ —	$ —
Alabama Power	35	—	500	800	1,335	1,335	—	—	—	35
Georgia Power	—	—	—	1,750	1,750	1,732	—	—	—	—
Gulf Power	30	25	225	—	280	280	45	—	20	10
Mississippi Power	100	—	—	—	100	100	—	—	—	100
Southern Power Company[b]	—	—	—	750	750	728	—	—	—	—
Southern Company Gas[c]	—	—	—	1,900	1,900	1,890	—	—	—	—
Other	30	—	—	—	30	30	20	—	20	10
Southern Company Consolidated	$195	$25	$725	$7,200	$8,145	$8,094	$65	$ —	$40	$155

(a) Represents the Southern Company parent entity.

(b) Does not include Southern Power's $120 million continuing letter of credit facility for standby letters of credit expiring in 2019, of which $19 million remains unused at December 31, 2017.

(c) Southern Company Gas, as the parent entity, guarantees the obligations of Southern Company Gas Capital, which is the borrower of $1.4 billion of these arrangements. Southern Company Gas' committed credit arrangements also include $500 million for which Nicor Gas is the borrower and which is restricted for working capital needs of Nicor Gas.

In May 2017, Southern Company, Alabama Power, Georgia Power, and Southern Power Company each amended certain of their multi-year credit arrangements, which, among other things, extended the maturity dates from 2020 to 2022. Southern Company and Southern Power Company increased their borrowing ability under these arrangements to $2.0 billion from $1.25 billion and to $750 million from $600 million, respectively. Southern Company also terminated its $1.0 billion facility maturing in 2018. Also in May 2017, Southern Company Gas Capital and Nicor Gas terminated their existing credit arrangements for $1.3 billion and $700 million, respectively, which were to mature in 2017 and 2018, and entered into a new multi-year credit arrangement with $1.4 billion and $500 million currently allocated to Southern Company Gas Capital and Nicor Gas, respectively, maturing in 2022. Pursuant to the new multi-year credit arrangement, the allocations between Southern Company Gas Capital and Nicor Gas may be adjusted. In September 2017, Alabama Power also amended its $500 million multi-year credit arrangement, which, among other things, extended the maturity date from 2018 to 2020. In November 2017, Gulf Power amended $195 million of its multi-year credit arrangements to extend the maturity dates from 2017 and 2018 to 2020 and Mississippi Power amended its one-year credit arrangements in an aggregate amount of $100 million to extend the maturity dates from 2017 to 2018.

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 ¼ 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 the other subsidiaries' 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 and other hybrid securities. 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, 2017, 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 $8.1 billion unused credit with banks is allocated to provide liquidity support to the 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 revenue bonds of the traditional electric operating companies outstanding requiring liquidity support as of December 31, 2017 was approximately $1.5 billion as compared to $1.9 billion at December 31, 2016. In addition, at December 31, 2017, the traditional electric operating companies had approximately $714 million of revenue bonds outstanding that were required to be remarketed within the next 12 months. Subsequent to December 31, 2017, $50 million of these revenue bonds of Mississippi Power which were in a long-term interest rate mode were remarketed in an index rate mode.

Southern Company, the traditional electric operating companies (other than Mississippi Power), 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. 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, 2017:		
Commercial paper	**$ 1,832**	**1.8%**
Short-term bank debt	**607**	**2.3%**
Total	**$ 2,439**	**1.9%**
December 31, 2016:		
Commercial paper	$ 1,909	1.1%
Short-term bank debt	123	1.7%
Total	$ 2,032	1.1%

In addition to the short-term borrowings of Southern Power Company included in the table above, at December 31, 2016, Southern Power Company subsidiaries had 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. The Project Credit Facilities were fully repaid in January 2017 and had total amounts outstanding of $209 million at a weighted average interest rate of 2.1% at December 31, 2016.

Redeemable Preferred Stock of Subsidiaries

At December 31, 2016, each of the traditional electric operating companies had outstanding preferred and/or preference stock. During 2017, Alabama Power and Gulf Power each redeemed all of its outstanding preference stock and Georgia Power redeemed all of its outstanding preferred and 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 did 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:

(in millions)	Redeemable Preferred Stock of Subsidiaries
Balance at December 31, 2014	$ 375
Issued	—
Redeemed	(262)
Issuance costs	5
Balance at December 31, 2015:	118
Issued	—
Redeemed	—
Balance at December 31, 2016:	118
Issued	250
Redeemed	(38)
Issuance costs	(6)
Balance at December 31, 2017:	**$ 324**

NOTE 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 2017, 2016, and 2015, the traditional electric operating companies and Southern Power incurred fuel expense of $4.4 billion, $4.4 billion, and $4.8 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 $235 million, $232 million, and $227 million for 2017, 2016, and 2015, respectively.

Estimated total obligations under these commitments at December 31, 2017 were as follows:

(in millions)	Operating Leases	Other
2018	$ 247	$ 7
2019	250	6
2020	247	4
2021	249	5
2022	252	4
2023 and thereafter	806	38
Total	$ 2,051	$64

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 35 million mmBtu at floating gas prices calculated using forward natural gas prices at December 31, 2017 and valued at $101 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, 2017 were as follows:

(in millions)	Pipeline Charges, Storage Capacity, and Gas Supply
2018	$ 813
2019	552
2020	416
2021	375
2022	339
2023 and thereafter	2,294
Total	$4,789

Operating Leases

The Southern Company system has operating lease agreements with various terms and expiration dates. Total rent expense was $176 million, $169 million, and $130 million for 2017, 2016, and 2015, respectively. Southern Company includes any step rents, fixed escalations, and lease concessions in its computation of minimum lease payments.

As of December 31, 2017, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
(in millions)	Barges & Railcars	Other(*)	Total
2018	$21	$ 128	$ 149
2019	11	113	124
2020	9	99	108
2021	8	87	95
2022	6	77	83
2023 and thereafter	5	963	968
Total	$60	$1,467	$1,527

(*) Includes operating leases for cellular tower space, facilities, vehicles, and other equipment.

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.

NOTE 8. COMMON STOCK

Stock Issued

During 2017, Southern Company issued approximately 14.6 million shares of common stock primarily through employee equity compensation plans and received proceeds of approximately $659 million.

In addition, during the second and third quarters of 2017, Southern Company issued a total of approximately 2.7 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 $134 million, net of $1.1 million in fees and commissions.

Shares Reserved

At December 31, 2017, a total of 71 million shares were reserved for issuance pursuant to the Southern Investment Plan, employee savings plans, the Outside Directors Stock Plan, the Omnibus Incentive Compensation Plan (which includes stock options and performance share units as discussed below), and an at-the-market program. Of the total 71 million shares reserved, there were 13 million shares of common stock remaining available for awards under the Omnibus Incentive Compensation Plan as of December 31, 2017.

Stock-Based Compensation

Stock-based compensation primarily in the form of performance share units and restricted stock 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. In 2015 and 2016, stock-based compensation consisted exclusively of performance share units. Beginning in 2017, stock-based compensation granted to employees includes restricted stock units in addition to performance share units. Prior to 2015, stock-based compensation also included stock options. As of December 31, 2017, there were 5,112 current and former employees participating in the stock option, performance share unit, and restricted stock 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.

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.

Southern Company issues performance share units with performance goals based on three performance goals to employees. These include performance share units with performance goals 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, performance share units with performance goals based on Southern Company's 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.

In 2015 and 2016, the EPS-based and ROE-based awards each represented 25% of the total target grant date fair value of the performance share unit awards granted. The remaining 50% of the total target grant date fair value consisted of TSR-based awards. Beginning in 2017, the total target grant date fair value of the stock compensation awards granted was comprised 20% each of EPS-based awards and ROE-based awards and 30% each of TSR-based awards and restricted stock units.

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.

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. Employees become immediately vested in the TSR-based performance share units, along with the EPS-based and ROE-based awards, upon retirement. 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 is based on the historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate is 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:

Year Ended December 31	**2017**	2016	2015
Expected volatility	**15.6%**	15.0%	12.9%
Expected term *(in years)*	**3**	3	3
Interest rate	**1.4%**	0.8%	1.0%
Weighted average grant-date fair value	**$49.08**	$45.06	$46.38

The weighted average grant-date fair value of both EPS-based and ROE-based performance share units granted during 2017, 2016, and 2015 was $49.21, $48.87, and $47.75, respectively.

Total unvested performance share units outstanding as of December 31, 2016 were 3.2 million. During 2017, 1.2 million performance share units were granted and 1.5 million performance share units were vested or forfeited, resulting in 2.9 million unvested performance share units outstanding at December 31, 2017. The number of shares to be issued for the three-year performance and vesting period ended December 31, 2017 will be determined in the first quarter 2018.

For the years ended December 31, 2017, 2016, and 2015, total compensation cost for performance share units recognized in income was $74 million, $96 million, and $88 million, respectively, with the related tax benefit also recognized in income of $29 million, $37 million, and $34 million, respectively. As of December 31, 2017, $30 million of total unrecognized compensation cost related to performance share award units will be recognized over a weighted-average period of approximately 21 months.

Restricted Stock Units

Beginning in 2017, stock-based compensation granted to employees included restricted stock units in addition to performance share units. One-third of the restricted stock units granted to employees vest each year throughout a three-year service period. All unvested restricted stock 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 vesting period.

The fair value of restricted stock units is based on the closing stock price of Southern Company common stock on the date of the grant. Since one-third of the restricted stock units vest each year throughout a three-year service period, compensation expense for restricted stock unit awards is generally recognized over the corresponding one-, two-, or three-year period. Employees become immediately vested in the restricted stock units upon retirement. 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 weighted average grant-date fair value of restricted stock units granted during 2017 was $49.25.

During 2017, 0.6 million restricted stock units were granted and 0.1 million restricted stock units were vested or forfeited, resulting in 0.7 million unvested restricted stock units outstanding at December 31, 2017, including previously issued restricted stock units related to other employee retention agreements.

For the year ended December 31, 2017, total compensation cost for restricted stock units recognized in income was $25 million with the related tax benefit also recognized in income of $10 million. As of December 31, 2017, $8 million of total unrecognized compensation cost related to restricted stock units will be recognized over a weighted-average period of approximately 13 months.

Stock Options

In 2015, Southern Company discontinued the granting of stock options and all outstanding options have vested. Stock options expire no later than 10 years after the grant date and the latest possible exercise will occur no later than November 2024.

Southern Company's activity in the stock option program for 2017 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
	(in millions)	
Outstanding at December 31, 2016	24.6	$41.28
Exercised	6.0	40.03
Cancelled	—	39.90
Outstanding and Exercisable at December 31, 2017	**18.6**	**$41.68**

As of December 31, 2017, the weighted average remaining contractual term for the options outstanding and options exercisable was approximately five years and the aggregate intrinsic value for the options outstanding and options exercisable was $119 million.

Total compensation cost for stock option awards and the related tax benefits recognized in income were immaterial for all years presented.

The total intrinsic value of options exercised during the years ended December 31, 2017, 2016, and 2015 was $64 million, $120 million, and $48 million, respectively. The actual tax benefit for the tax deductions from stock option exercises totaled $25 million, $46 million, and $19 million for the years ended December 31, 2017, 2016, and 2015, 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, 2017, 2016, and 2015 was $239 million, $448 million, and $154 million, respectively.

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. Under the terms of the restricted stock 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 0.7 million restricted stock units 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.

For the years ended December 31, 2017 and 2016, total compensation cost for restricted stock units recognized in income was $8 million and $13 million, respectively, and the related tax benefit also recognized in income was $4 million for each year. As of December 31, 2017, $3 million of total unrecognized compensation cost related to restricted stock units will be recognized over a weighted-average period of approximately 12 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.

For the years ended December 31, 2017 and 2016, total compensation cost for the change in control awards recognized in income was $12 million and $4 million, respectively. The related tax benefit also recognized in income was $6 million for the year ended December 31, 2017 and an immaterial amount for the year ended December 31, 2016. As of December 31, 2017, approximately $8 million of total unrecognized compensation cost related to change in control awards will be recognized over a weighted-average period of approximately 18 months.

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		
(in millions)	**2017**	2016	2015
As reported shares	**1,000**	951	910
Effect of options and performance share award units	**8**	7	4
Diluted shares	**1,008**	958	914

Prior to the adoption of ASU 2016–09 in 2016, 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. Stock options and performance share award units that were not included in the diluted EPS calculation because they were anti-dilutive were immaterial in all years presented.

Common Stock Dividend Restrictions

The income of Southern Company is derived primarily from equity in earnings of its subsidiaries. At December 31, 2017, consolidated retained earnings included $5.3 billion of undistributed retained earnings of the subsidiaries.

NOTE 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 $450 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 and policies 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. 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, 2017 under the NEIL policies would be $55 million and $81 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.

NOTE 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, 2017, 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, 2017:	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)]	$ 331	$ 239	$ —	$ —	$ 570
Interest rate derivatives	—	1	—	—	1
Foreign currency derivatives	—	129	—	—	129
Nuclear decommissioning trusts:[(c)]					
Domestic equity	690	82	—	—	772
Foreign equity	62	224	—	—	286
U.S. Treasury and government agency securities	—	251	—	—	251
Municipal bonds	—	68	—	—	68
Corporate bonds	21	315	—	—	336
Mortgage and asset backed securities	—	57	—	—	57
Private equity	—	—	—	29	29
Other	19	12	—	—	31
Cash equivalents	1,455	—	—	—	1,455
Other investments	9	—	1	—	10
Total	$2,587	$1,378	$ 1	$29	$3,995
Liabilities:					
Energy-related derivatives[(a)(b)]	$ 480	$ 253	$ —	$ —	$ 733
Interest rate derivatives	—	38	—	—	38
Foreign currency derivatives	—	23	—	—	23
Contingent consideration	—	—	22	—	22
Total	$ 480	$ 314	$22	$ —	$ 816

(a) Energy-related derivatives exclude $11 million associated with premiums and certain weather derivatives accounted for based on intrinsic value rather than fair value.

(b) Energy-related derivatives exclude cash collateral of $193 million.

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

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, currencies, and payables related to pending investment purchases and the securities lending program. 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 primarily obligated to make generation-based payments to the seller commencing at the commercial operation date through 2026. The obligation is categorized as Level 3 under Fair Value Measurements as the fair value is determined using significant unobservable inputs for the forecasted facility generation in MW-hours, as well as other inputs such as 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 periodic 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 has been determined based on market factors including comparable multiples and the expectations regarding cash flows and business plan executions.

As of December 31, 2017 and 2016, 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, 2017	**$29**	**$21**	**Not Applicable**	**Not Applicable**
As of December 31, 2016	$20	$25	Not Applicable	Not Applicable

Private equity funds include a fund-of-funds that invests in high-quality private equity funds across several market sectors, funds that invest 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, 2017 and 2016, other financial instruments for which the carrying amount did not equal fair value were as follows:

(in millions)	Carrying Amount	Fair Value
Long-term debt, including securities due within one year:		
2017	**$48,151**	**$51,348**
2016	$45,080	$46,286

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, and Southern Company Gas.

NOTE 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. Southern Company Gas' wholesale gas operations use various contracts in its commercial activities that generally meet the definition of derivatives. For the traditional electric operating companies, Southern Power, and Southern Company Gas' other businesses, 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 retains exposure to price changes that can, in a volatile energy market, adversely affect results of operations.

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, 2017, the net volume of energy-related derivative contracts for natural gas positions totaled 621 million mmBtu for the Southern Company system, with the longest hedge date of 2021 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 2026 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 32 million mmBtu.

The estimated pre-tax gains (losses) related to energy-related derivatives that will be reclassified from accumulated OCI to earnings for the 12-month period ending December 31, 2018 total $(11) million for Southern Company.

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, 2017, 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, 2017
	(in millions)				*(in millions)*
Cash Flow Hedges of Existing Debt					
	$ 900	1-month LIBOR	0.79%	March 2018	$ 1
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	(3)
	200	4.25%	3-month LIBOR + 2.46%	December 2019	(1)
	300	2.75%	3-month LIBOR + 0.92%	June 2020	(2)
	1,500	2.35%	1-month LIBOR + 0.87%	July 2021	(31)
Total	$3,650				$(36)

The estimated pre-tax gains (losses) related to interest rate derivatives expected to be reclassified from accumulated OCI to interest expense for the next 12-month period ending December 31, 2018 total $(20) million. Deferred gains and losses are expected to be amortized into earnings through 2046.

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, 2017, 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, 2017
	(in millions)		*(in millions)*			*(in millions)*
Cash Flow Hedges of Existing Debt						
	$ 677	2.95%	€ 600	1.00%	June 2022	$ 55
	564	3.78%	500	1.85%	June 2026	51
Total	$1,241		€1,100			$106

The estimated pre-tax gains (losses) related to foreign currency derivatives that will be reclassified from accumulated OCI to earnings for the next 12-month period ending December 31, 2018 total $(23) million.

Derivative Financial Statement Presentation and Amounts

Southern Company and its subsidiaries enter into 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. 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. 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, 2017 and 2016, 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	**2017**		2016	
	Assets	**Liabilities**	Assets	Liabilities
		(in millions)		
Derivatives designated as hedging instruments for regulatory purposes				
Energy-related derivatives:				
Other current assets/Other current liabilities	**$ 10**	**$ 43**	$ 73	$ 27
Other deferred charges and assets/Other deferred credits and liabilities	**7**	**24**	25	33
Total derivatives designated as hedging instruments for regulatory purposes	**$ 17**	**$ 67**	$ 98	$ 60
Derivatives designated as hedging instruments in cash flow and fair value hedges				
Energy-related derivatives:				
Other current assets/Other current liabilities	**$ 3**	**$ 14**	$ 23	$ 7
Interest rate derivatives:				
Other current assets/Other current liabilities	**1**	**4**	12	1
Other deferred charges and assets/Other deferred credits and liabilities	**—**	**34**	1	28
Foreign currency derivatives:				
Other current assets/Other current liabilities	**—**	**23**	—	25
Other deferred charges and assets/Other deferred credits and liabilities	**129**	**—**	—	33
Total derivatives designated as hedging instruments in cash flow and fair value hedges	**$ 133**	**$ 75**	$ 36	$ 94
Derivatives not designated as hedging instruments				
Energy-related derivatives:				
Other current assets/Other current liabilities	**$ 380**	**$ 437**	$ 489	$ 483
Other deferred charges and assets/Other deferred credits and liabilities	**170**	**215**	66	81
Interest rate derivatives:				
Other current assets/Other current liabilities	**—**	**—**	1	—
Total derivatives not designated as hedging instruments	**$ 550**	**$ 652**	$ 556	$ 564
Gross amounts recognized	**$ 700**	**$ 794**	$ 690	$ 718
Gross amounts offset[(a)]	**$(405)**	**$(598)**	$(462)	$(524)
Net amounts recognized in the Balance Sheets[(b)]	**$ 295**	**$ 196**	$ 228	$ 194

(a) Gross amounts offset include cash collateral held on deposit in broker margin accounts of $193 million and $62 million as of December 31, 2017 and 2016, respectively.
(b) Net amounts of derivative instruments outstanding exclude premiums and intrinsic value associated with weather derivatives of $11 million as of December 31, 2017.

At December 31, 2017 and 2016, the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivatives designated as regulatory hedging instruments and deferred were as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	Balance Sheet Location	**2017**	2016	Balance Sheet Location	**2017**	2016
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$(34)**	$(16)	Other regulatory liabilities, current	**$7**	$56
	Other regulatory assets, deferred	**(18)**	(19)	Other regulatory liabilities, deferred	**1**	12
Total energy-related derivative gains (losses)[(*)]		**$(52)**	$(35)		**$8**	$68

(*) Fair value gains and losses recorded in regulatory assets and liabilities include cash collateral held on deposit in broker margin accounts of $6 million and $8 million as of December 31, 2017 and 2016, respectively.

For the years ended December 31, 2017, 2016, and 2015, 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) Amount			Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)	Amount		
Derivative Category	**2017**	2016	2015	Statements of Income Location	**2017**	2016	2015
		(in millions)				*(in millions)*	
Energy-related derivatives	**$ (47)**	$ 18	$ —	Depreciation and amortization	**$ (16)**	$ 2	$ —
				Cost of natural gas	**(2)**	(1)	—
Interest rate derivatives	**(2)**	(180)	(22)	Interest expense, net of amounts capitalized	**(21)**	(18)	(9)
Foreign currency derivatives	**140**	(58)	—	Interest expense, net of amounts capitalized	**(23)**	(13)	—
				Other income (expense), net(*)	**160**	(82)	—
Total	**$ 91**	$(220)	$(22)		**$ 98**	$(112)	$ (9)

(*) 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 euro-denominated notes.

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

For the years ended December 31, 2017, 2016, and 2015, 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	**2017**	2016	2015
			(in millions)	
Interest rate derivatives:	Interest expense, net of amounts capitalized	**$(22)**	$ (21)	$2

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.

For the years ended December 31, 2017, 2016, and 2015, 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	**2017**	2016	2015
			(in millions)	
Energy-related derivatives	Wholesale electric revenues	**$ (4)**	$ 2	$(5)
	Fuel	**—**	—	3
	Natural gas revenues(*)	**(80)**	33	—
	Cost of natural gas	**(2)**	3	—
Total		**$(86)**	$38	$(2)

(*) Excludes gains (losses) recorded in natural gas revenues associated with weather derivatives of $23 million and $6 million for the years ended December 31, 2017 and 2016, respectively.

For the years ended December 31, 2017, 2016, and 2015, 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, 2017, the Company had no collateral posted with derivative counterparties to satisfy these arrangements.

At December 31, 2017, the fair value of energy-related and interest rate derivative liabilities with contingent features was $15 million and $7 million, respectively. The maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $14 million and $7 million for energy-related and interest rate derivative contracts, respectively.

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 Southern Company system 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, 2017, cash collateral posted in these accounts was immaterial. Southern Company Gas 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, 2017, cash collateral held on deposit in broker margin accounts was $193 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.

In addition, Southern Company Gas conducts credit evaluations and obtains appropriate internal approvals for the counterparty's line of credit before any transaction with the counterparty is executed. In most cases, the counterparty must have an investment grade rating, which includes a minimum long-term debt rating of Baa3 from Moody's and BBB- from S&P. Generally, Southern Company Gas requires credit enhancements by way of a guaranty, cash deposit, or letter of credit for transaction counterparties that do not have investment grade ratings.

Southern Company Gas also utilizes master netting agreements whenever possible to mitigate exposure to counterparty credit risk. When Southern Company Gas is engaged in more than one outstanding derivative transaction with the same counterparty and it also has a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and a reasonable measure of Southern Company Gas' credit risk. Southern Company Gas also uses other netting agreements with certain counterparties with whom it conducts significant transactions. Master netting agreements enable Southern Company Gas to net certain assets and liabilities by counterparty. Southern Company Gas also nets across product lines and against cash collateral provided the master netting and cash collateral agreements include such provisions. Southern Company Gas may require counterparties to pledge additional collateral when deemed necessary.

Southern Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

NOTE 12. ACQUISITIONS AND DISPOSITIONS

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 final purchase price allocation:

Southern Company Gas Purchase Price *(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 interest	(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 Southern Company's consolidated financial statements from the date of acquisition and consist of operating revenues of $3.9 billion and $1.7 billion and net income of $243 million and $114 million for 2017 and 2016, respectively.

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.

Acquisition of PowerSecure

In May 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.

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 following table presents the final purchase price allocation:

PowerSecure Purchase Price *(in millions)*	
Current assets	$172
Property, plant, and equipment	46
Intangible assets	106
Goodwill	284
Other assets	4
Current liabilities	(121)
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 $284 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 Southern Company's 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.

Southern Power

During 2017 and 2016, in accordance with its overall growth strategy, Southern Power or one of its wholly-owned subsidiaries, acquired or contracted to acquire the projects discussed below. Also, in March 2016, Southern Power acquired an additional 15% interest in Desert Stateline, 51% of which was initially acquired in 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. Acquisition-related costs were expensed as incurred and were not material for any of the years presented.

The following table presents Southern Power's acquisition activity for the year ended, and subsequent to, December 31, 2017.

Project Facility	Resource	Seller; Acquisition Date	Approximate Nameplate Capacity (MW)	Location	Southern Power Percentage Ownership	Actual/ Expected COD	PPA Contract Period
Business Acquisitions During the Year Ended December 31, 2017							
Bethel	Wind	Invenergy Wind Global LLC, January 6, 2017	276	Castro County, TX	100%	January 2017	12 years
Cactus Flats[(a)]	Wind	RES America Developments, Inc. July 31, 2017	148	Concho County, TX	100%	Third quarter 2018	12 years and 15 years
Business Acquisitions Subsequent to December 31, 2017							
Gaskell West 1	Solar	Recurrent Energy Development Holdings, LLC, January 26, 2018	20	Kern County, CA	100% of[(b)] Class B	March 2018	20 years

(a) On July 31, 2017, Southern Power purchased 100% of the Cactus Flats facility and commenced construction. Upon placing the facility in service, Southern Power expects to close on a tax equity partnership agreement that has already been executed, subject to various customary conditions at closing, and will then own 100% of the class B membership interests.
(b) Southern Power owns 100% of the class B membership interest under a tax equity partnership agreement.

Business Acquisitions During the Year Ended December 31, 2017

Southern Power's aggregate purchase price for acquisitions during the year ended December 31, 2017 was $539 million. The fair values of the assets acquired and liabilities assumed were finalized in 2017 and recorded as follows:

(in millions)	2017
Restricted cash	$ 16
CWIP	534
Other assets	5
Accounts payable	(16)
Total purchase price	$ 539

In 2017, total revenues of $15 million and net income of $17 million, primarily as a result of PTCs, was recognized by Southern Power related to the 2017 acquisitions. The Bethel facility did not have operating revenues or activities prior to completion of construction and being placed in service, and the Cactus Flats facility is still under construction. Therefore, supplemental pro forma information as though the acquisitions occurred as of the beginning of 2017 and for the comparable 2016 period is not meaningful and has been omitted.

Construction Projects in Progress

During the year ended December 31, 2017, in accordance with its overall growth strategy, Southern Power continued construction on the 345-MW Mankato expansion project and commenced construction on the Cactus Flats facility. Total aggregate construction costs for these facilities, excluding acquisition costs and including construction costs to complete the subsequently-acquired Gaskell West 1 solar project, are expected to be between $385 million and $430 million. At December 31, 2017, construction costs included in CWIP related to these projects totaled $188 million. The ultimate outcome of these matters cannot be determined at this time.

Development Projects

During 2017, as part of Southern Power's renewable development strategy, Southern Power purchased wind turbine equipment from Siemens Wind Power, Inc. and Vestas-American Wind Technology, Inc. to be used for various development and construction projects, up to 900 MWs in total. Once these wind projects reach commercial operations, which is expected in 2021, they are expected to qualify for 80% PTCs.

During 2016, Southern Power entered into a joint development agreement with Renewable Energy Systems Americas, Inc. to develop and construct approximately 3,000 MWs of wind projects expected to be placed in service between 2018 and 2020. In addition, in 2016, Southern Power purchased 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.

The following table presents Southern Power's acquisitions for the year ended December 31, 2016.

Project Facility	Resource	Seller, Acquisition Date	Approximate Nameplate Capacity *(MW)*	Location	Ownership Percentage	Actual COD	PPA Contract Period
Acquisitions for the Year Ended December 31, 2016							
Boulder 1	Solar	SunPower 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	100% [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 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%	April 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	100% [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 October 26, 2016	257	Floyd and Crosby Counties, TX	90.1% [f]	October 2016	12 years

(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 originally purchased 90%, with a minority owner owning 10%. During 2017, Southern Power acquired the remaining 10% ownership interest.

(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 PPA and the expansion PPA, approximately $442 million of assets, primarily related to property, plant, and equipment, are subject to lien at December 31, 2017.
(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. The total aggregate purchase price including minority ownership contributions and the assumption of non-recourse construction debt to Southern Power was approximately $2.6 billion for these acquisitions. In connection with Southern Power's 2016 acquisitions, allocations of the purchase price to individual assets were finalized during the year ended December 31, 2017 with no changes to amounts originally reported for Boulder 1, Grant Plains, Grant Wind, Henrietta, Mankato, Passadumkeag, Salt Fork, Tyler Bluff, and Wake Wind. The fair values of the assets and liabilities acquired through the business combinations were recorded as follows:

(in millions)	2016
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. See Note 1 for additional information.
(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 $29 million was payable at December 31, 2017.
(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.

Southern Company Gas

Investment in Southern Natural Gas

In September 2016, Southern Company Gas completed its acquisition from Kinder Morgan, Inc. of a 50% equity interest in Southern Natural Gas Company, L.L.C. (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. The purchase price of the acquisition was approximately $1.4 billion. The investment in SNG is accounted for using the equity method.

Acquisition of Remaining Interest in SouthStar

SouthStar Energy Services, LLC (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 Natural Gas Company, Inc.'s (Piedmont) owning the remaining 15%. In October 2016, Southern Company Gas purchased Piedmont's 15% interest in SouthStar for $160 million.

Proposed Sale of Elizabethtown Gas and Elkton Gas

On October 15, 2017, Southern Company Gas subsidiary, Pivotal Utility Holdings, entered into agreements for the sale of the assets of two of its natural gas distribution utilities, Elizabethtown Gas and Elkton Gas, to South Jersey Industries, Inc. for a total cash purchase price of $1.7 billion. The completion of each asset sale is subject to the satisfaction or waiver of certain conditions, including, among other customary closing conditions, the receipt of required regulatory approvals, including the FERC, the Federal Communications Commission, the New Jersey BPU, and, with respect to the sale of Elkton Gas, the Maryland PSC. Southern Company Gas and South Jersey Industries, Inc. made joint filings on December 22, 2017 and January 16, 2018 with the New Jersey BPU and the Maryland PSC, respectively, requesting regulatory approval. The asset sales are expected to be completed by the end of the third quarter 2018.

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

NOTE 13. SEGMENT AND RELATED INFORMATION

The primary businesses of the Southern Company system are electricity sales by the traditional electric operating companies and Southern Power and 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 develops, 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 $392 million, $419 million, and $417 million in 2017, 2016, and 2015, respectively. Revenues from sales of natural gas from Southern Company Gas to the traditional electric operating companies and Southern Power were $23 million and $119 million, respectively, in 2017 and $11 million and $17 million, respectively, in 2016. 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, 2017, 2016, and 2015 was as follows:

	Electric Utilities							
(in millions)	Traditional Electric Operating Companies	Southern Power	Eliminations	Total	Southern Company Gas	All Other	Eliminations	Consolidated
2017								
Operating revenues	**$16,884**	**$ 2,075**	**$(419)**	**$18,540**	**$ 3,920**	**$ 741**	**$ (170)**	**$ 23,031**
Depreciation and amortization	**1,954**	**503**	**—**	**2,457**	**501**	**52**	**—**	**3,010**
Interest income	**14**	**7**	**—**	**21**	**3**	**11**	**(9)**	**26**
Earnings from equity method investments	**1**	**—**	**—**	**1**	**106**	**(1)**	**—**	**106**
Interest expense	**820**	**191**	**—**	**1,011**	**200**	**490**	**(7)**	**1,694**
Income taxes	**1,021**	**(939)**	**—**	**82**	**367**	**(307)**	**—**	**142**
Segment net income (loss)(a)(b)(c)	**(193)**	**1,071**	**—**	**878**	**243**	**(279)**	**—**	**842**
Total assets	**72,204**	**15,206**	**(325)**	**87,085**	**22,987**	**2,552**	**(1,619)**	**111,005**
Gross property additions	**3,836**	**268**	**—**	**4,104**	**1,525**	**355**	**—**	**5,984**
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

(in millions)	Electric Utilities: Traditional Electric Operating Companies	Electric Utilities: Southern Power	Electric Utilities: Eliminations	Electric Utilities: Total	Southern Company Gas	All Other	Eliminations	Consolidated
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

(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 $3.4 billion ($2.4 billion after tax) in 2017, $428 million ($264 million after tax) in 2016, and $365 million ($226 million after tax) in 2015. See Note 3 under "Kemper County Energy Facility – Schedule and Cost Estimate" for additional information.
(c) Segment net income (loss) for the traditional electric operating companies also includes a pre-tax charge for the write-down of Gulf Power's ownership of Plant Scherer Unit 3 of $33 million ($20 million after tax) in 2017. See Note 3 under "Regulatory Matters – Gulf Power – Retail Base Rate Cases" for additional information.

Products and Services

Year	Electric Utilities' Revenues: Retail	Wholesale	Other	Total
		(in millions)		
2017	**$15,330**	**$2,426**	**$784**	**$18,540**
2016	15,234	1,926	781	17,941
2015	14,987	1,798	657	17,442

Year	Southern Company Gas' Revenues: Gas Distribution Operations	Gas Marketing Services	All Other	Total
		(in millions)		
2017	**$3,024**	**$860**	**$36**	**$3,920**
2016	1,266	354	32	1,652

NOTE 14. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2017 and 2016 is as follows:

				Per Common Share				
							Trading Price Range	
Quarter Ended	Operating Revenues	Operating Income	Consolidated Net Income Attributable to Southern Company	Basic Earnings	Diluted Earnings	Dividends	High	Low
		(in millions)						
March 2017	**$5,771**	**$ 1,306**	**$ 658**	**$ 0.66**	**$ 0.66**	**$0.5600**	**$51.47**	**$47.57**
June 2017	**5,430**	**(1,594)**	**(1,381)**	**(1.38)**	**(1.37)**	**0.5800**	**51.97**	**47.87**
September 2017	**6,201**	**2,045**	**1,069**	**1.07**	**1.06**	**0.5800**	**50.80**	**46.71**
December 2017	**5,629**	**794**	**496**	**0.49**	**0.49**	**0.5800**	**53.51**	**47.92**
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

As a result of the revisions to the cost estimate for the Kemper IGCC and its June 2017 suspension, Mississippi Power recorded total pre-tax charges to income related to the Kemper IGCC of $208 million ($185 million after tax) in the fourth quarter 2017, $34 million ($21 million after tax) in the third quarter 2017, $3.0 billion ($2.1 billion after tax) in the second quarter 2017, $108 million ($67 million after tax) in the first quarter 2017, $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, and $53 million ($33 million after tax) in the first quarter 2016. See Note 3 under "Kemper County Energy Facility" for additional information.

As a result of the Tax Reform Legislation, the Southern Company system recorded a total income tax benefit of $264 million in the fourth quarter 2017. See Note 5 for additional information.

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

Selected Consolidated Financial and Operating Data

For the Periods Ended December 2013 through 2017

	2017	2016[(a)]	2015	2014	2013
Operating Revenues (in millions)	**$ 23,031**	$ 19,896	$ 17,489	$ 18,467	$ 17,087
Total Assets (in millions)[(b)(c)]	**$ 111,005**	$109,697	$ 78,318	$ 70,233	$ 64,264
Gross Property Additions (in millions)	**$ 5,984**	$ 7,624	$ 6,169	$ 6,522	$ 5,868
Return on Average Common Equity (percent)[(d)]	**3.44**	10.80	11.68	10.08	8.82
Cash Dividends Paid Per Share of Common Stock	**$ 2.3000**	$ 2.2225	$ 2.1525	$ 2.0825	$ 2.0125
Consolidated Net Income Attributable to Southern Company (in millions)[(d)]	**$ 842**	$ 2,448	$ 2,367	$ 1,963	$ 1,644
Earnings Per Share —					
Basic	**$ 0.84**	$ 2.57	$ 2.60	$ 2.19	$ 1.88
Diluted	**0.84**	2.55	2.59	2.18	1.87
Capitalization (in millions):					
Common stock equity	**$ 24,167**	$ 24,758	$ 20,592	$ 19,949	$ 19,008
Preferred and preference stock of subsidiaries and noncontrolling interests	**1,361**	1,854	1,390	977	756
Redeemable preferred stock of subsidiaries	**324**	118	118	375	375
Redeemable noncontrolling interests	**—**	164	43	39	—
Long-term debt[(b)]	**44,462**	42,629	24,688	20,644	21,205
Total (excluding amounts due within one year)	**$ 70,314**	$ 69,523	$ 46,831	$ 41,984	$ 41,344
Capitalization Ratios (percent):					
Common stock equity	**34.4**	35.6	44.0	47.5	46.0
Preferred and preference stock of subsidiaries and noncontrolling interests	**1.9**	2.7	3.0	2.3	1.8
Redeemable preferred stock of subsidiaries	**0.5**	0.2	0.3	0.9	0.9
Redeemable noncontrolling interests	**—**	0.2	0.1	0.1	—
Long-term debt[(b)]	**63.2**	61.3	52.6	49.2	51.3
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	**$ 23.99**	$ 25.00	$ 22.59	$ 21.98	$ 21.43
Market price per share:					
High	**$ 53.51**	$ 54.64	$ 53.16	$ 51.28	$ 48.74
Low	**46.71**	46.00	41.40	40.27	40.03
Close (year-end)	**48.09**	49.19	46.79	49.11	41.11
Market-to-book ratio (year-end) (percent)	**200.5**	196.8	207.2	223.4	191.8
Price-earnings ratio (year-end) (times)	**57.3**	19.1	18.0	22.4	21.9
Dividends paid (in millions)	**$ 2,300**	$ 2,104	$ 1,959	$ 1,866	$ 1,762
Dividend yield (year-end) (percent)	**4.8**	4.5	4.6	4.2	4.9
Dividend payout ratio (percent)	**273.2**	86.0	82.7	95.0	107.1
Shares outstanding (in thousands):					
Average	**1,000,336**	951,332	910,024	897,194	876,755
Year-end	**1,007,603**	990,394	911,721	907,777	887,086
Stockholders of record (year-end)	**120,803**	126,338	131,771	137,369	143,800

(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 and $139 million is reflected for years 2014 and 2013, 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 and $143 million is reflected for years 2014 and 2013, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(d) A significant loss to income was recorded by Mississippi Power related to the suspension of the Kemper IGCC in June 2017. Earnings in all periods presented were impacted by losses related to the Kemper IGCC.

	2017	2016[a]	2015	2014	2013
Operating Revenues (in millions):					
Residential	**$ 6,515**	$ 6,614	$ 6,383	$ 6,499	$ 6,011
Commercial	**5,439**	5,394	5,317	5,469	5,214
Industrial	**3,262**	3,171	3,172	3,449	3,188
Other	**114**	55	115	133	128
Total retail	**15,330**	15,234	14,987	15,550	14,541
Wholesale	**2,426**	1,926	1,798	2,184	1,855
Total revenues from sales of electricity	**17,756**	17,160	16,785	17,734	16,396
Natural gas revenues	**3,791**	1,596	—	—	—
Other revenues	**1,484**	1,140	704	733	691
Total	**$ 23,031**	$ 19,896	$ 17,489	$ 18,467	$ 17,087
Kilowatt-Hour Sales (in millions):					
Residential	**50,536**	53,337	52,121	53,347	50,575
Commercial	**52,340**	53,733	53,525	53,243	52,551
Industrial	**52,785**	52,792	53,941	54,140	52,429
Other	**846**	883	897	909	902
Total retail	**156,507**	160,745	160,484	161,639	156,457
Wholesale sales	**49,034**	37,043	30,505	32,786	26,944
Total	**205,541**	197,788	190,989	194,425	183,401
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**12.89**	12.40	12.25	12.18	11.89
Commercial	**10.39**	10.04	9.93	10.27	9.92
Industrial	**6.18**	6.01	5.88	6.37	6.08
Total retail	**9.80**	9.48	9.34	9.62	9.29
Wholesale	**4.95**	5.20	5.89	6.66	6.88
Total sales	**8.64**	8.68	8.79	9.12	8.94
Average Annual Kilowatt-Hour Use Per Residential Customer	**11,618**	12,387	13,318	13,765	13,144
Average Annual Revenue Per Residential Customer	**$ 1,498**	$ 1,541	$ 1,630	$ 1,679	$ 1,562
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**46,936**	46,291	44,223	46,549	45,502
Maximum Peak-Hour Demand (megawatts):					
Winter	**31,956**	32,272	36,794	37,234	27,555
Summer	**34,874**	35,781	36,195	35,396	33,557
System Reserve Margin (at peak) (percent)[b]	**30.8**	34.2	33.2	19.8	21.5
Annual Load Factor (percent)	**61.4**	61.5	59.9	59.6	63.2
Plant Availability (percent):					
Fossil-steam	**84.5**	86.4	86.1	85.8	87.7
Nuclear	**94.7**	93.3	93.5	91.5	91.5

(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.

Selected Consolidated Financial and Operating Data (continued)

For the Periods Ended December 2013 through 2017

	2017	2016[a]	2015	2014	2013
Source of Energy Supply (percent):					
Coal	**27.0**	30.3	32.3	39.3	36.9
Nuclear	**14.5**	14.5	15.2	14.8	15.5
Oil and gas	**41.9**	41.7	42.7	37.0	37.2
Hydro	**2.1**	2.1	2.6	2.5	3.9
Other	**5.4**	2.4	0.8	0.4	0.1
Purchased power	**9.1**	9.0	6.4	6.0	6.4
Total	**100.0**	100.0	100.0	100.0	100.0
Gas Sales Volumes (mmBtu in millions):					
Firm	**667**	296	—	—	—
Interruptible	**95**	53	—	—	—
Total	**762**	349	—	—	—
Traditional Electric Operating Company Customers (year-end) (in thousands):					
Residential	**4,011**	3,970	3,928	3,890	3,859
Commercial[b]	**599**	595	590	586	582
Industrial[b]	**18**	17	17	17	17
Other	**12**	11	11	11	9
Total electric customers	**4,640**	4,593	4,546	4,504	4,467
Gas distribution operations customers	**4,623**	4,586	—	—	—
Total utility customers	**9,263**	9,179	4,546	4,504	4,467
Employees (year-end)	**31,344**	32,015	26,703	26,369	26,300

(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 2013–2015 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.